The Greenidge Multi-Pollutant Control Project: Demonstration of an Innovative Retrofit Option for Smaller Coal-Fired Power Plants

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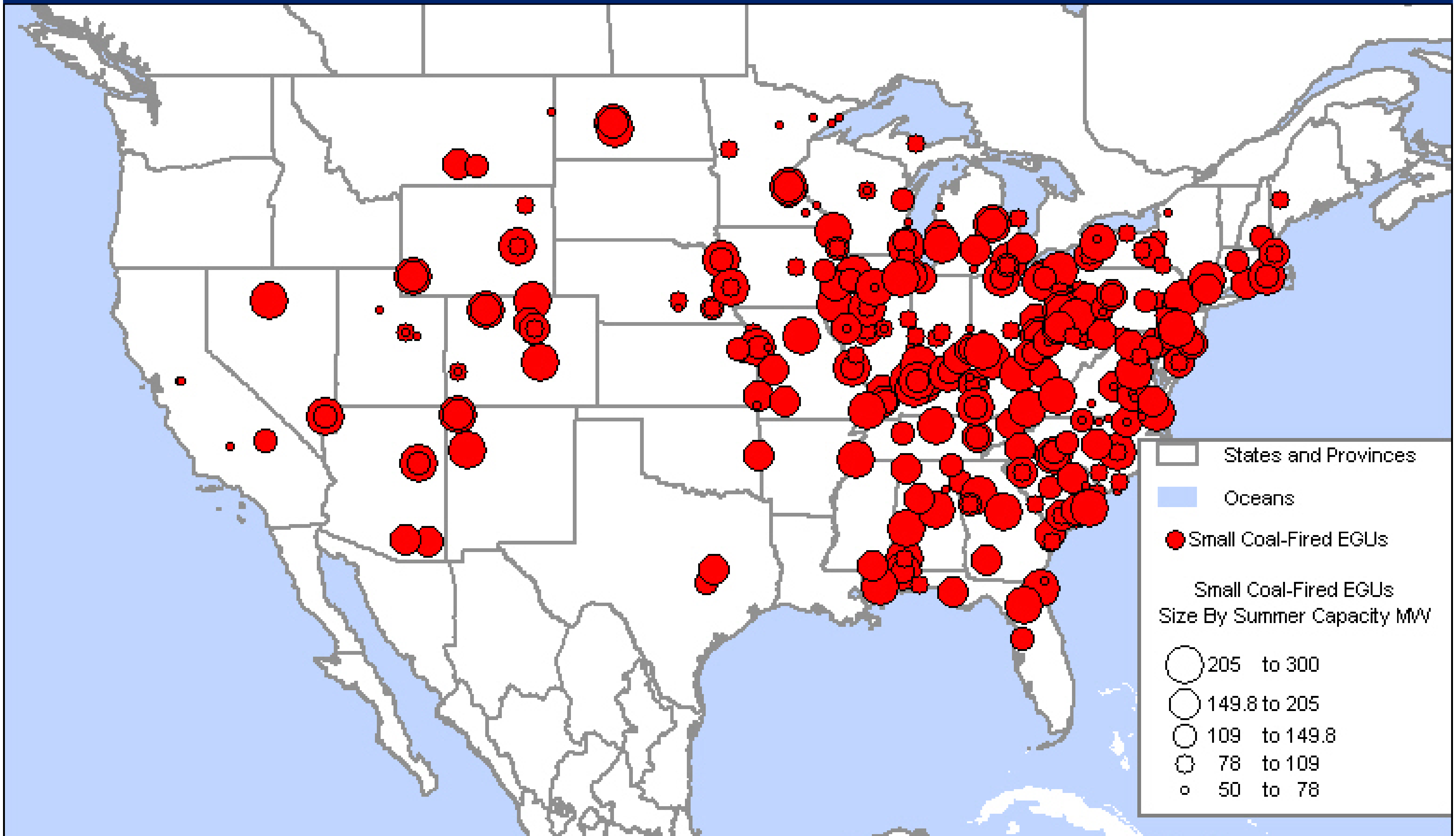
Greenidge Multi-Pollutant Control Project

- Part of U.S. DOE's Power Plant Improvement Initiative
- Participants
  - CONSOL Energy Inc. (administration, testing, reporting)
  - AES Greenidge LLC (host site, operations)
  - Babcock Power Environmental Inc. (EPC contractor)
- Funding
  - U.S. Department of Energy, National Energy Technology Laboratory
  - AES Greenidge LLC
- Goal: Demonstrate a multi-pollutant control system that can cost-effectively reduce emissions of NO_x, SO_2, mercury, acid gases (SO_3, HCl, HF), and particulate matter from smaller coal-fired EGUs

Existing U.S. Coal-Fired EGUs

50-300 MW_e



Existing U.S. Coal-Fired EGUs
50-300 MW_e

- ~ 420 units not equipped with FGD, SCR, or Hg control
  - Represent almost 60 GW of installed capacity
  - Greater than 80% are located east of the Mississippi River
  - Most have not announced plans to retrofit
- Difficult to retrofit for deep emission reductions
  - Large capital costs
  - Space limitations
- Increasingly vulnerable to retirement or fuel switching because of progressively more stringent environmental regulations
  - CAIR, Hg MACT, CAVR, state regulations
- Need to commercialize technologies designed to meet the environmental compliance requirements of these units

AES Greenidge Unit 4
(Boiler 6)

- Dresden, NY
- Commissioned in 1953
- 107 MW_e (EIA net winter capacity)
- Reheat unit
- Boiler:
  - Combustion Engineering tangentially-fired, balanced draft
  - 780,000 lb/h steam flow at 1465 psig and 1005 ^oF
- Fuel:
  - Eastern U.S. bituminous coal
  - Biomass (waste wood) – up to 10% heat input
- Existing emission controls:
  - Overfire air (natural gas reburn not in use)
  - ESP
  - No FGD – mid/high-sulfur coal to meet permit limit of 3.8 lb SO_2/MMBtu

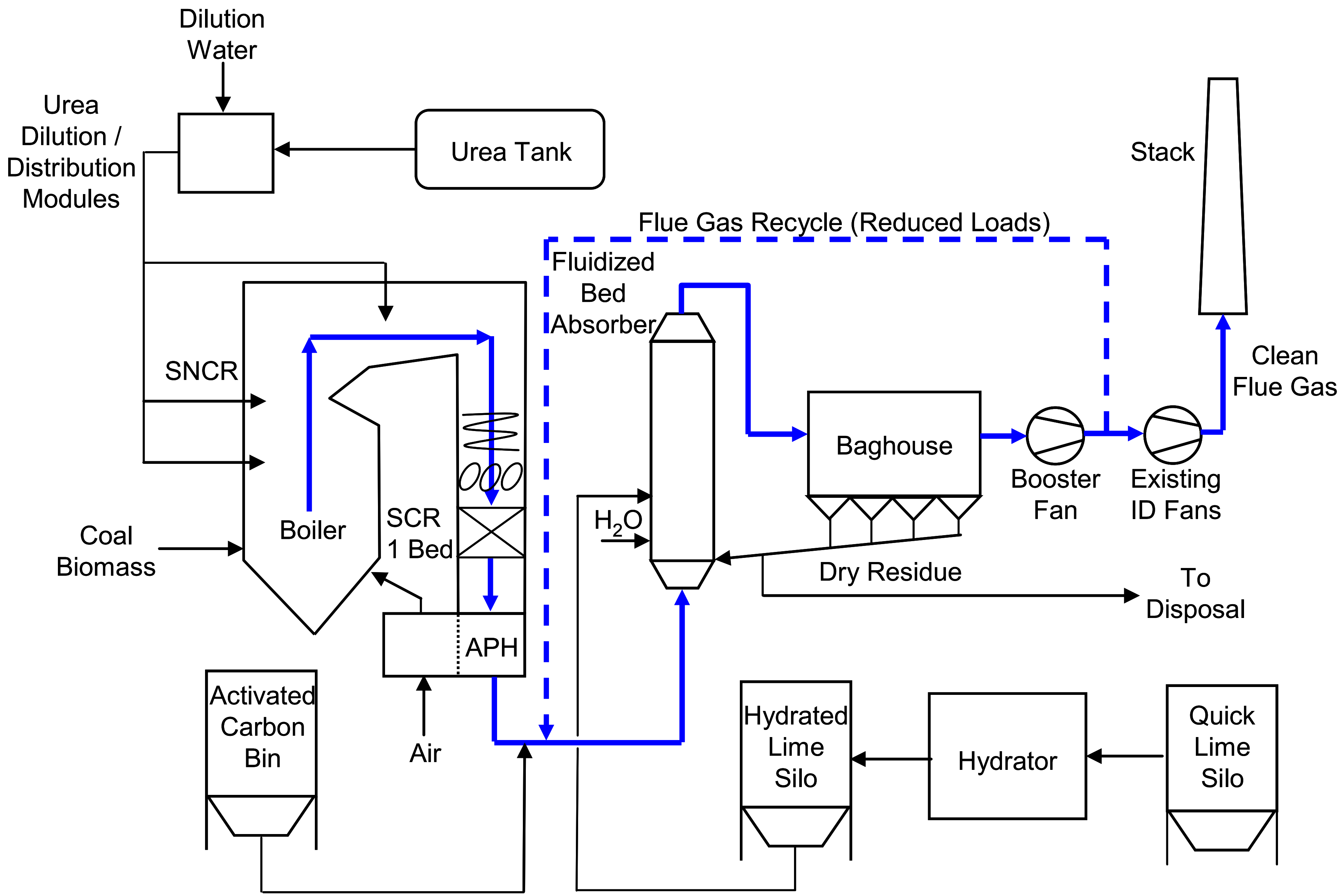
Design Objectives

- Deep emission reductions
- Low capital costs
- Small space requirements
- Applicability to high-sulfur coals
- Low maintenance requirements
- Operational flexibility

Multi-Pollutant Control Process

- Combustion modifications
  - Low-NO_x burners and overfire air
  - Installed outside of DOE scope
- NO_xOUT CASCADE® hybrid SNCR/SCR (Fuel Tech)
  - Urea-based, in-furnace selective non-catalytic reduction
  - Single-bed, in-duct selective catalytic reduction
- Activated carbon injection
- Turbosorp® circulating fluidized bed dry scrubber (Austrian Energy / Babcock Power Environmental)
- Pulsejet baghouse

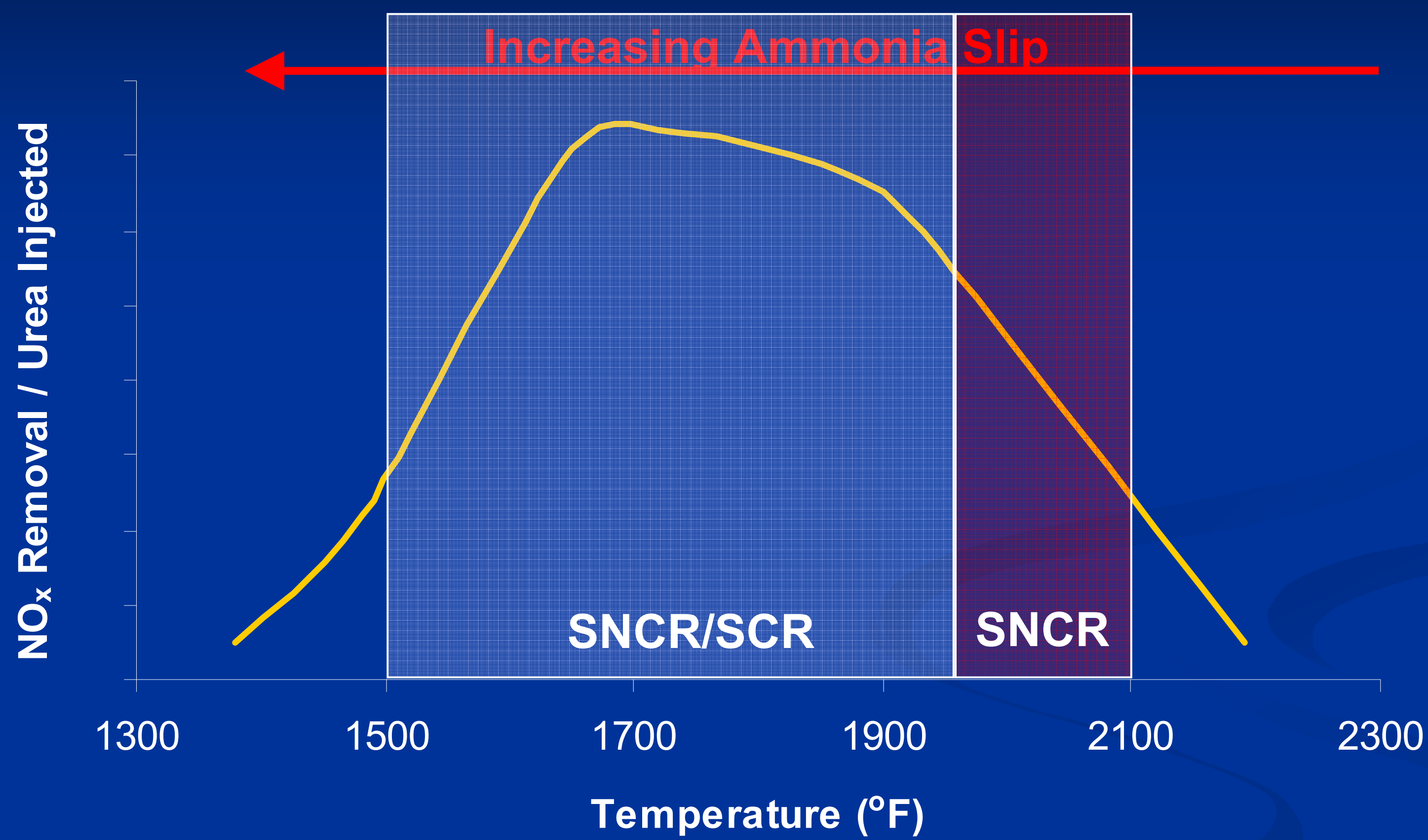
Process Flow Diagram



Hybrid NO_x Control

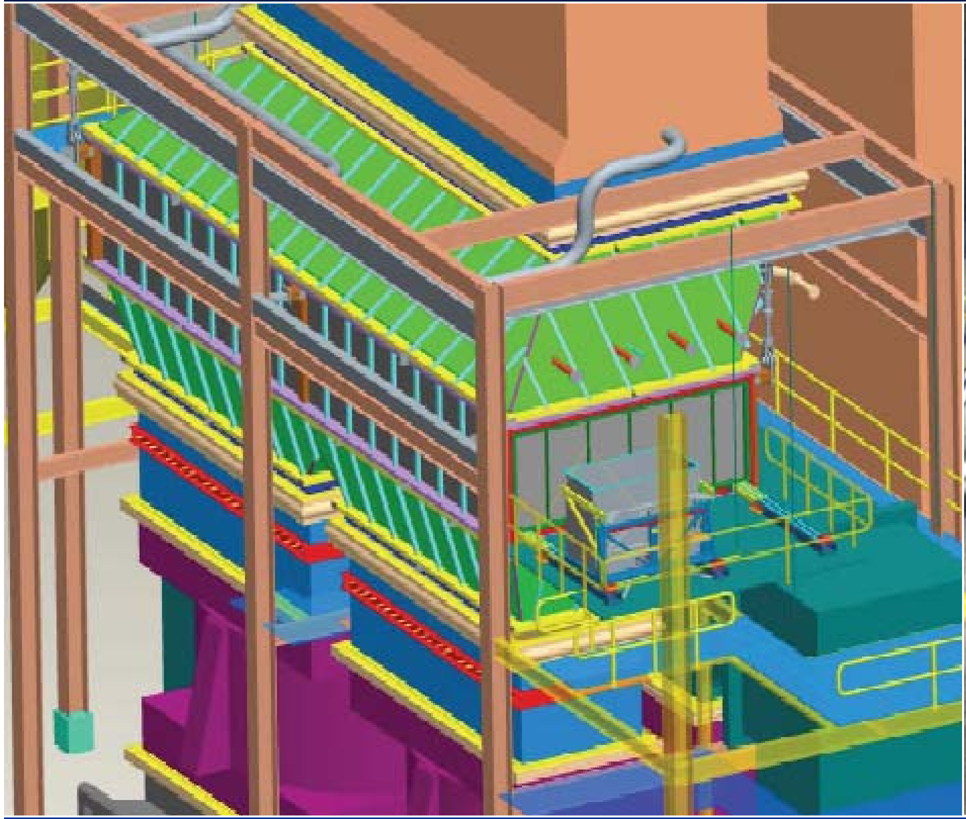
- Combustion Modifications
  - Replace coal, combustion air, and overfire air nozzles
  - Improve fuel/air mixing, burner exit velocity, secondary airflow control, and upper furnace mixing; reduce CO
  - Reduce NO_x to 0.25 lb/MMBtu
- SNCR
  - $CO(NH_2)_2 + 2\ NO + \frac{1}{2}\ O_2 \rightarrow 2\ N_2 + CO_2 + 2\ H_2O$
  - Reduce NO_x by ~ 42.5% (to 0.144 lb/MMBtu)
- SCR
  - $4\ NO + 4\ NH_3 + O_2 \rightarrow 4\ N_2 + 6\ H_2O$
  - $NO + NO_2 + 2\ NH_3 \rightarrow 2\ N_2 + 3\ H_2O$
  - Reduce NO_x by > 30% (to ≤ 0.10 lb/MMBtu)

SNCR for Hybrid System



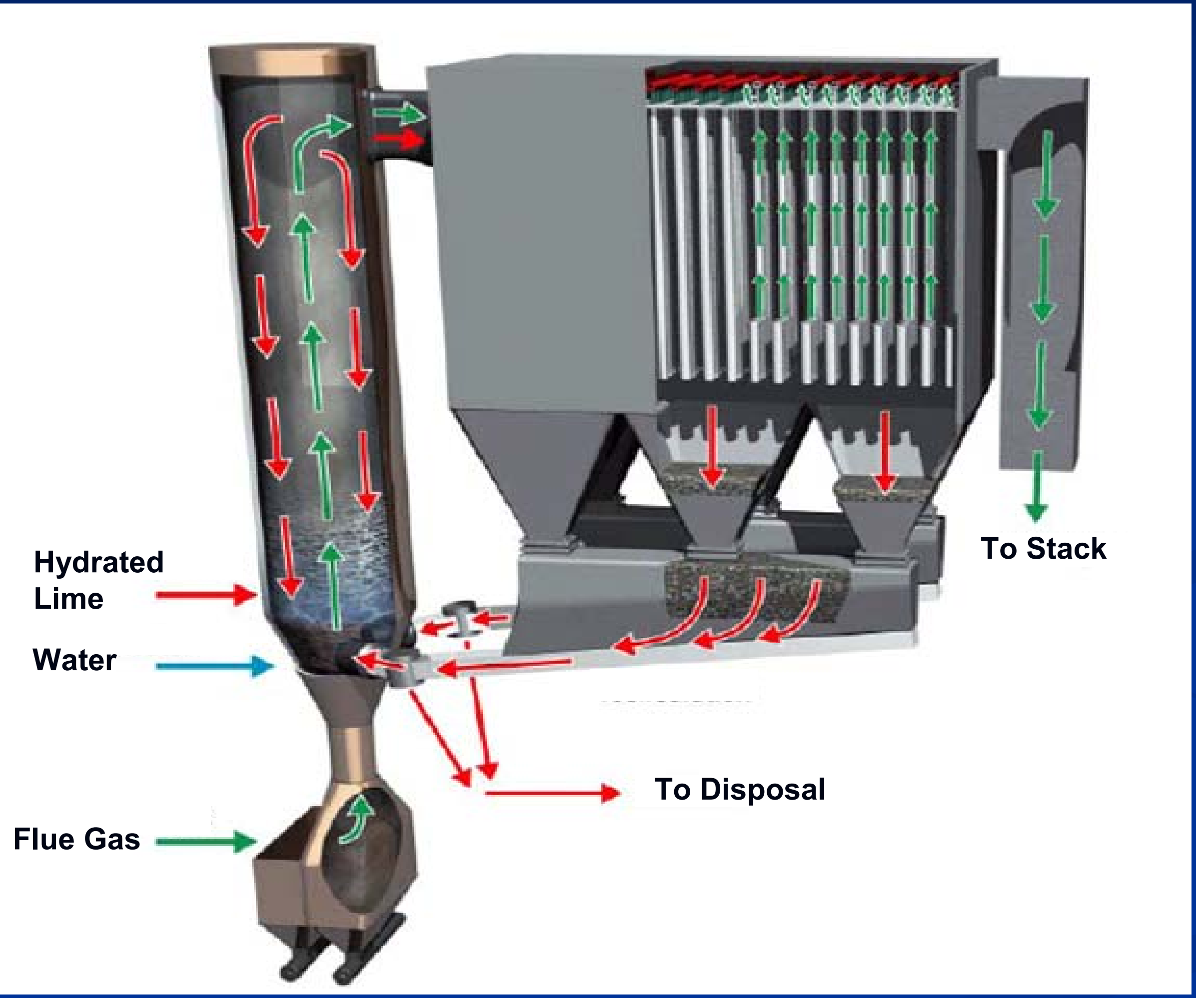
- Hybrid SNCR operates at lower temperature than stand-alone SNCR
  - Enables greater NO_x reduction and better urea utilization by SNCR
  - Provides ammonia slip for additional NO_x reduction by SCR

Single-Bed, In-Duct SCR



- Compact design
  - Bed depth ~ 1.3 m
  - Cross section ~ 45’ x 14’
- No ammonia injection grid
- Designed for lower NO_x removal efficiency than conventional SCR
- Includes Delta Wing™ static mixers to improve reagent, flow, temperature, and ash distribution

Turbosorp® System



- Completely dry
- Separate control of hydrate, water, and recycled solid injection
- High solids recirculation
- Applicable to high-sulfur coals
- 15-25% lower reagent consumption than spray dryers
- Low capital and maintenance costs relative to other FGD technologies

Circulating Fluidized Bed Dry Scrubber Chemistry

$$Ca(OH)_2 + SO_2 \leftrightarrow CaSO_3 \cdot \tfrac{1}{2} H_2O + \tfrac{1}{2} H_2O$$

$$Ca(OH)_2 + SO_3 \leftrightarrow CaSO_4 \cdot \tfrac{1}{2} H_2O + \tfrac{1}{2} H_2O$$

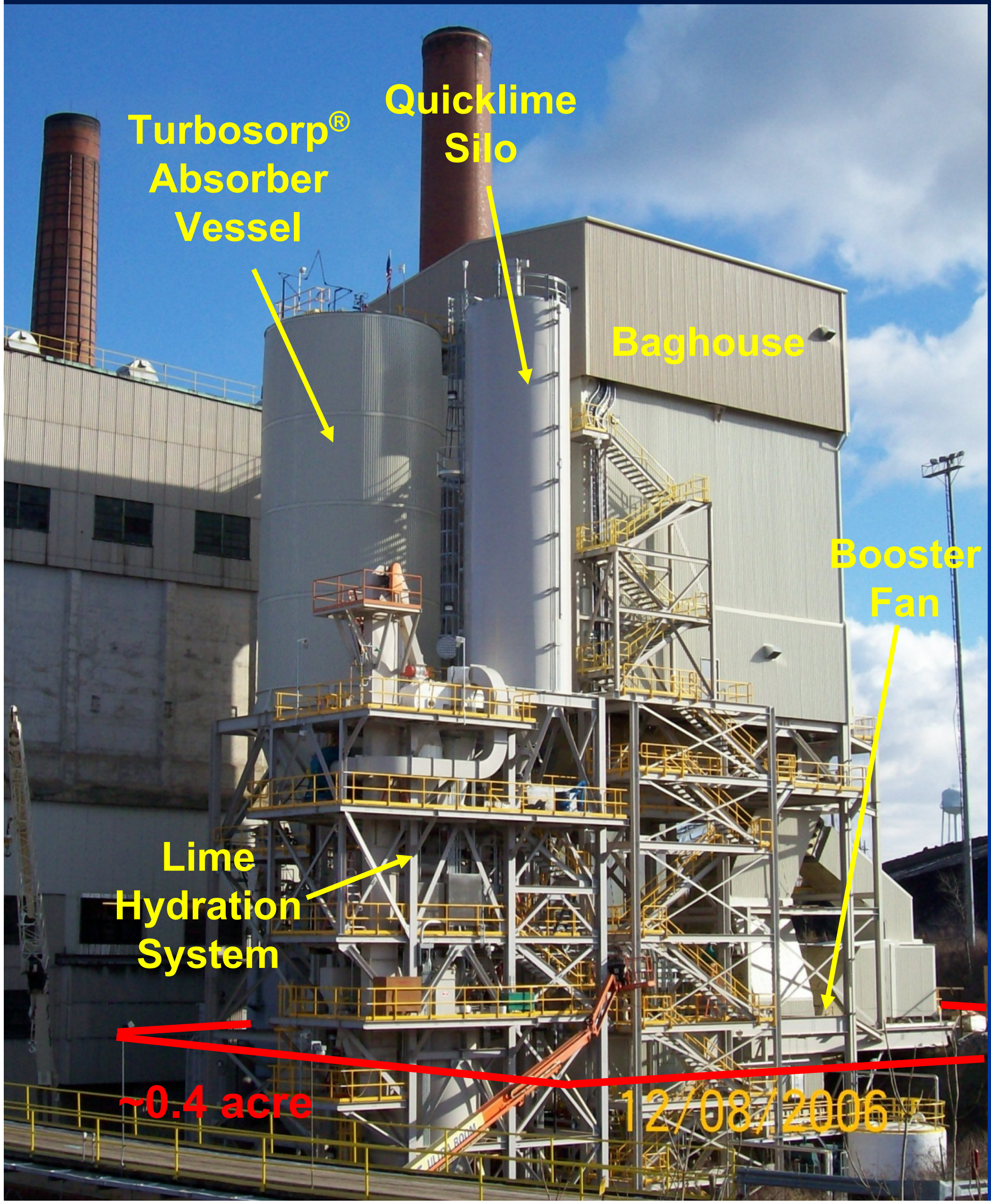
$$CaSO_3 \cdot \tfrac{1}{2} H_2O + \tfrac{1}{2} O_2 \leftrightarrow CaSO_4 \cdot \tfrac{1}{2} H_2O$$

$$Ca(OH)_2 + 2\ HCl \leftrightarrow CaCl_2 + 2\ H_2O$$

$$Ca(OH)_2 + 2\ HF \leftrightarrow CaF_2 + 2\ H_2O$$

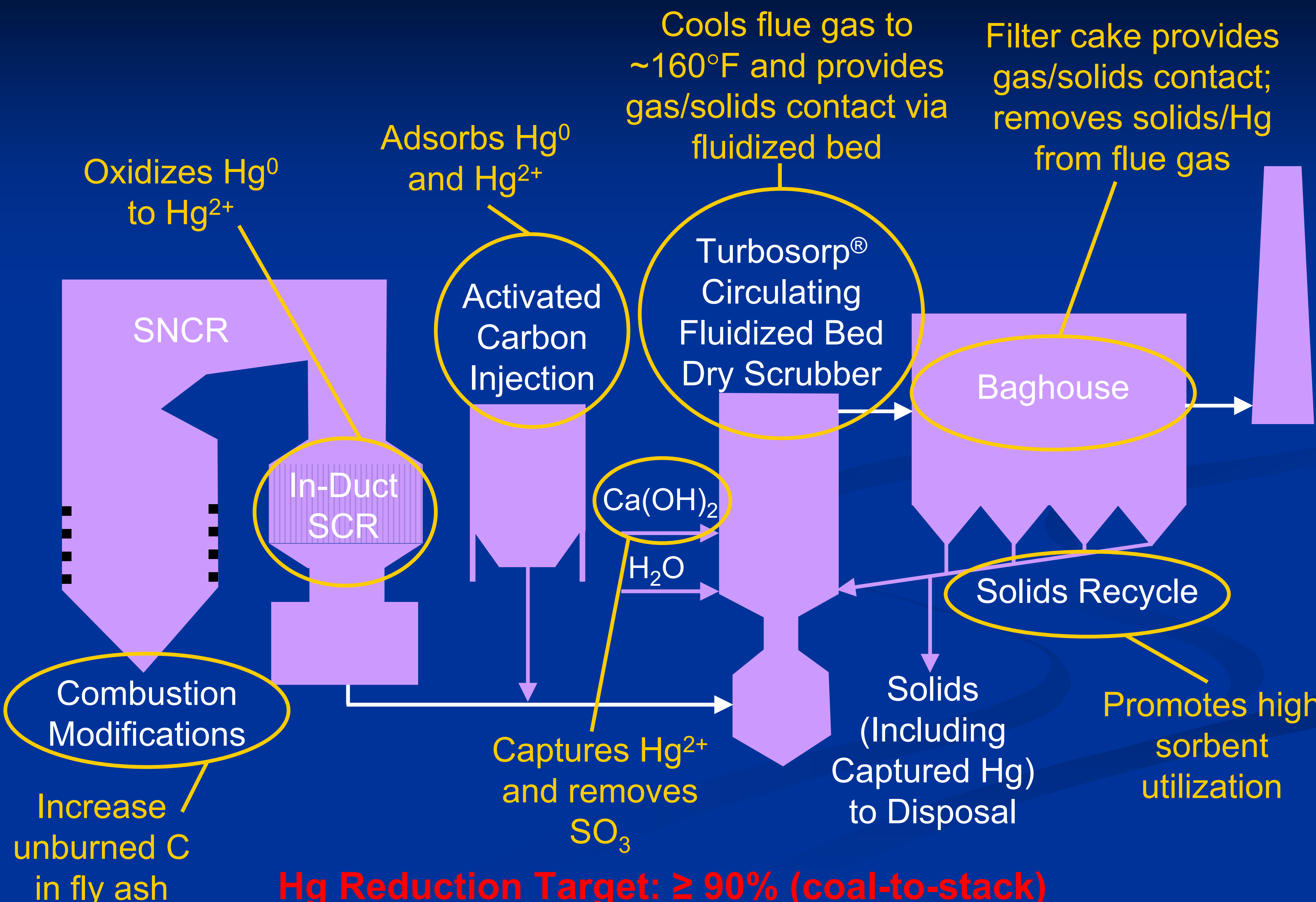
$$Ca(OH)_2 + CO_2 \leftrightarrow CaCO_3 + H_2O$$

AES Greenidge Installation



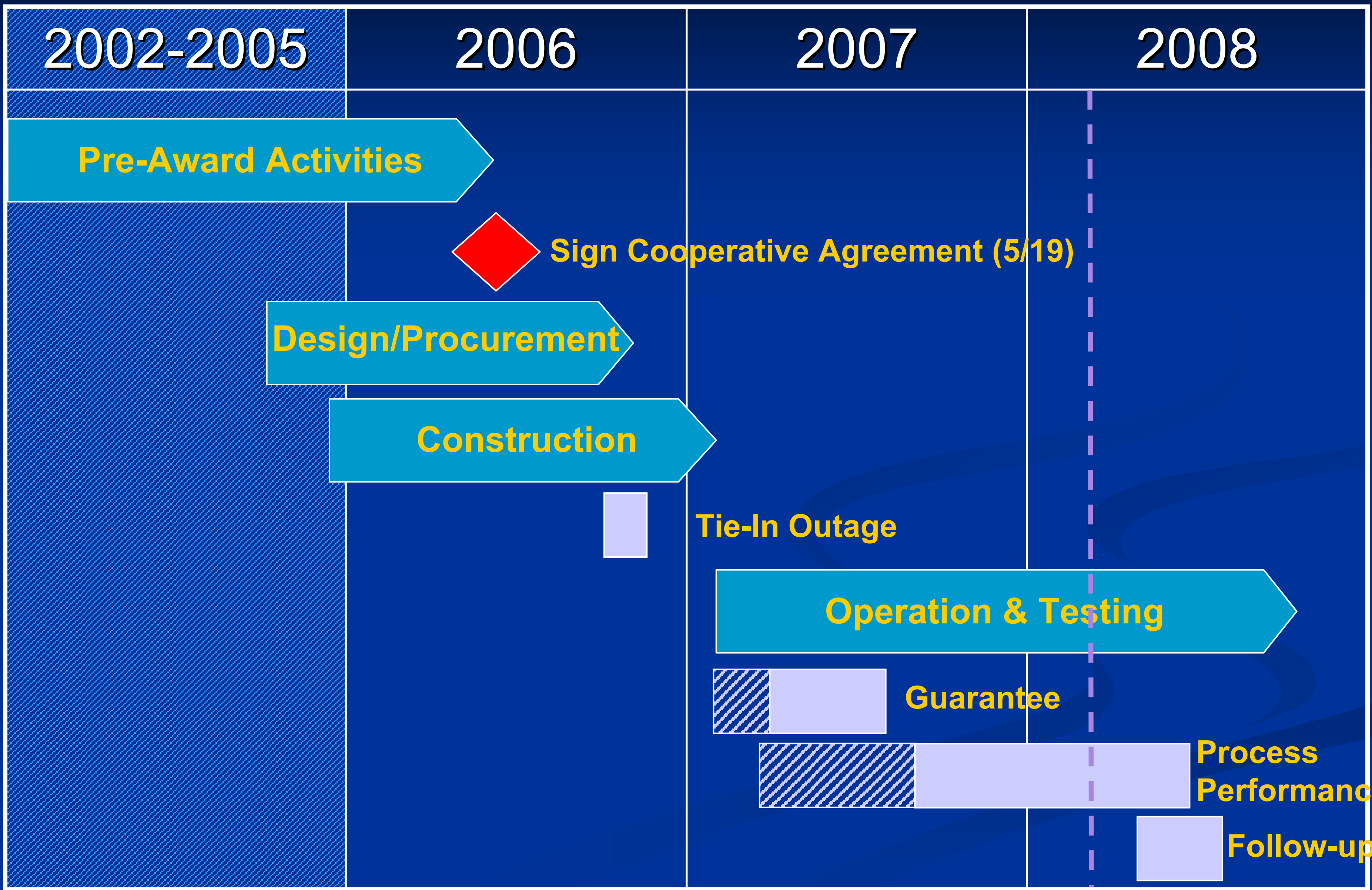
- Small footprint
- Carbon steel construction
- Includes:
  - Activated carbon injection system
  - Onsite lime hydration system
  - Eight-compartment pulsejet fabric filter
  - Booster fan
- Uses existing stack (liner not required)
- Projected Ca/S is 1.6-1.7 mol/mol for design fuel

Design Features for Mercury Control



Hg Reduction Target: ≥ 90% (coal-to-stack)

Project Schedule



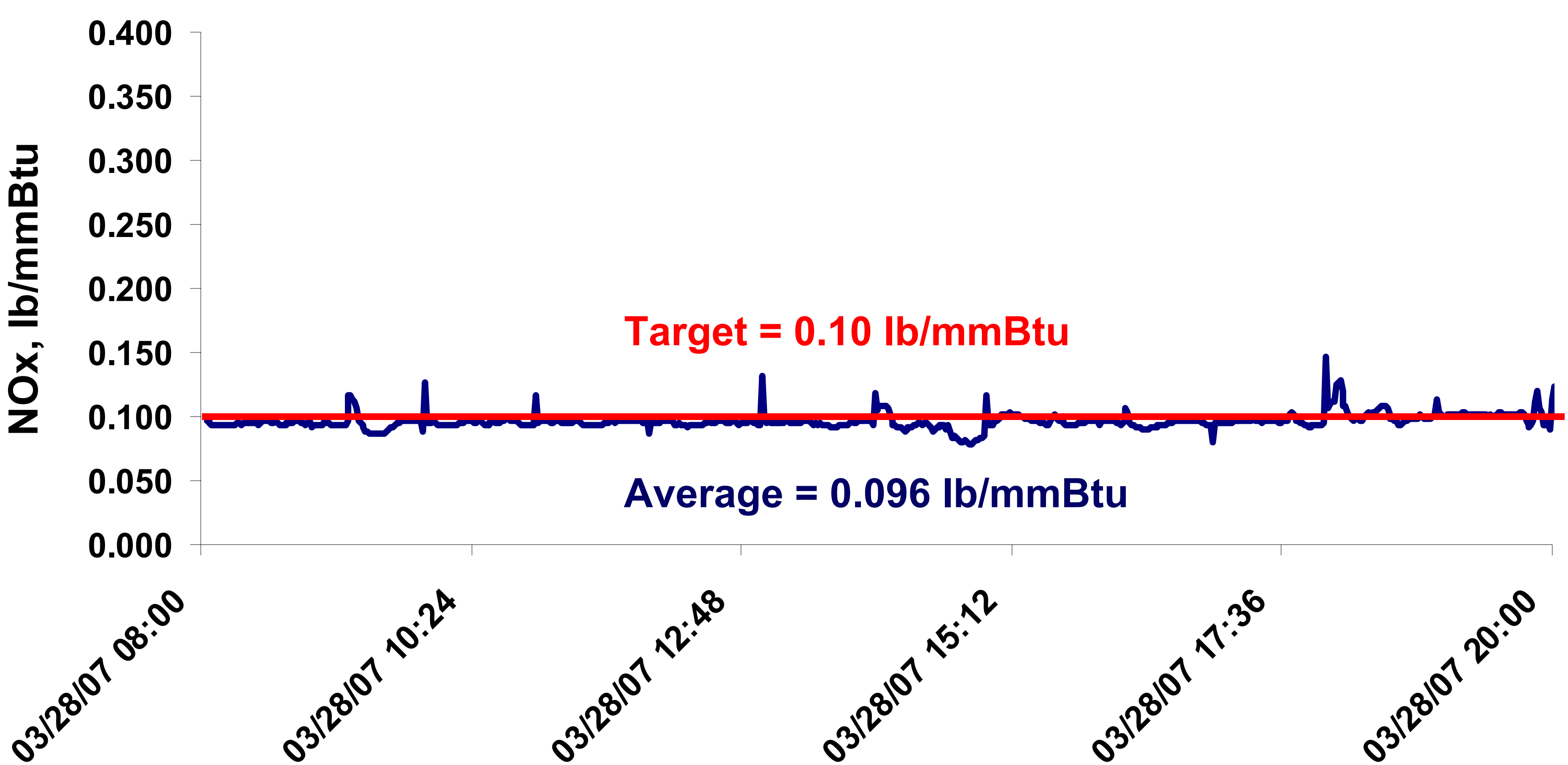
Guarantee Tests

March-May 2007, 2.4-3.2% Sulfur Eastern U.S. Bituminous Coal

Parameter	Performance Target	Measured Performance
NO_x emission rate	≤ 0.10 lb/mmBtu	0.10 lb/mmBtu*
SO_2 removal	≥ 95%	96%
Hg removal Activated C Injection No Activated C Injection	≥ 90%	 ≥94% ≥95%
SO_3 removal	≥ 95%	97%
HCl removal	≥ 95%	97%
HF removal	≥ 95%	Indeterminate

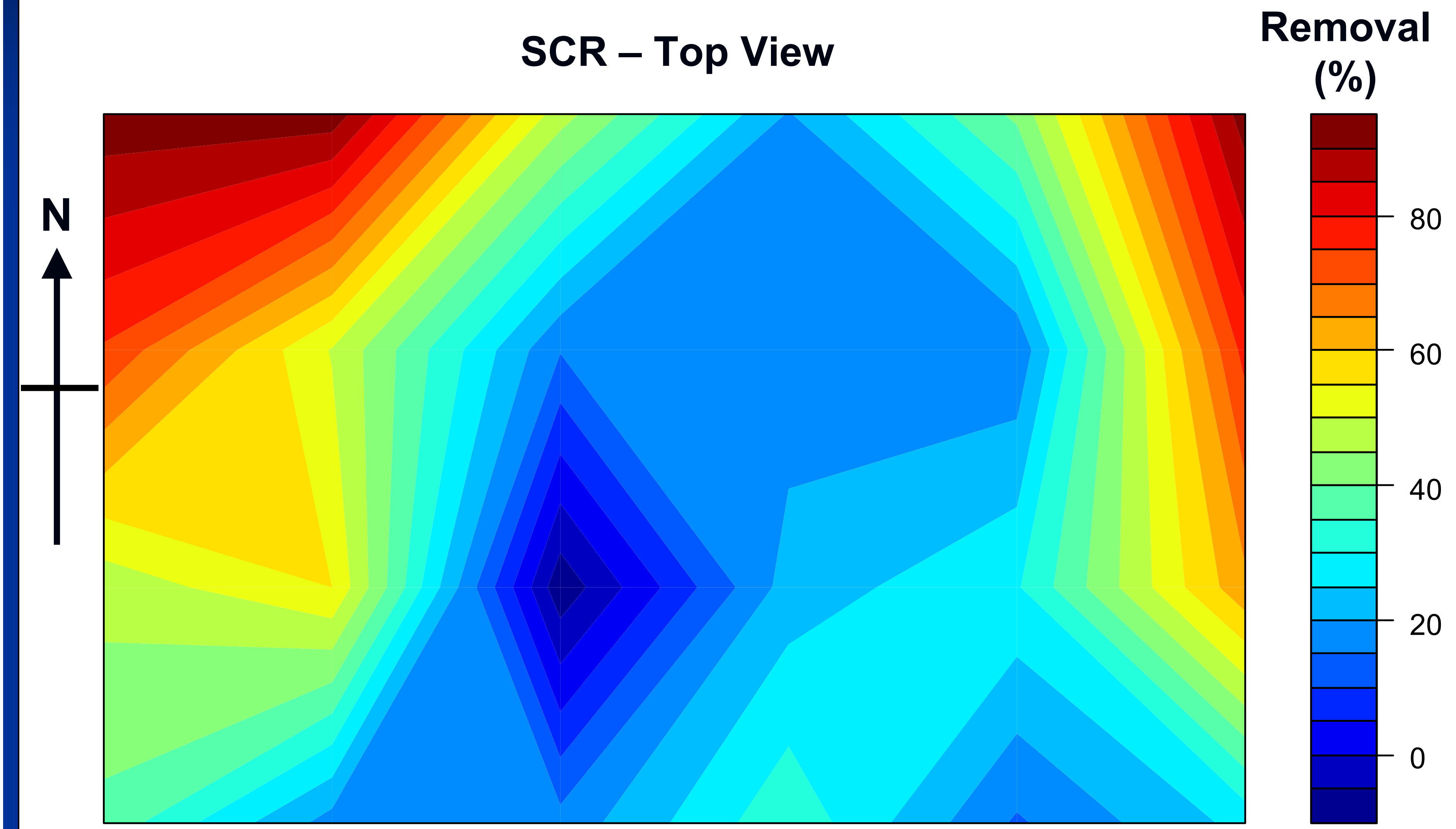
* Performance of hybrid NO_x control system has been affected by large particle ash and ammonia slip. Plant typically operates at 0.10-0.15 lb/mmBtu to maintain acceptable combustion characteristics.

NO$_x$ Emission Rate
March 28, 2007



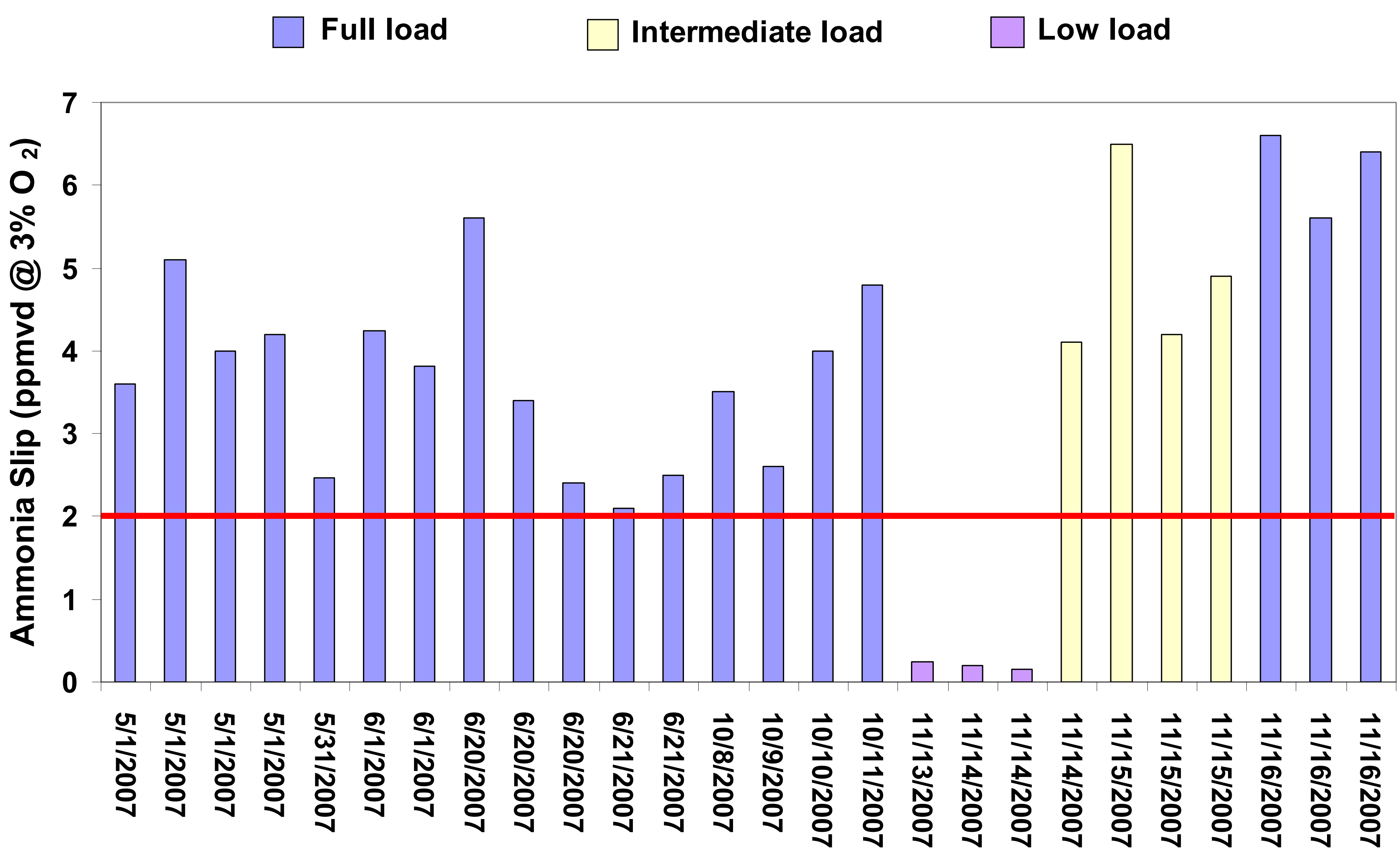
NO$_x$ Removal Across SCR

March 28, 2007 – Three-Test Average



Ammonia Slip Testing Results

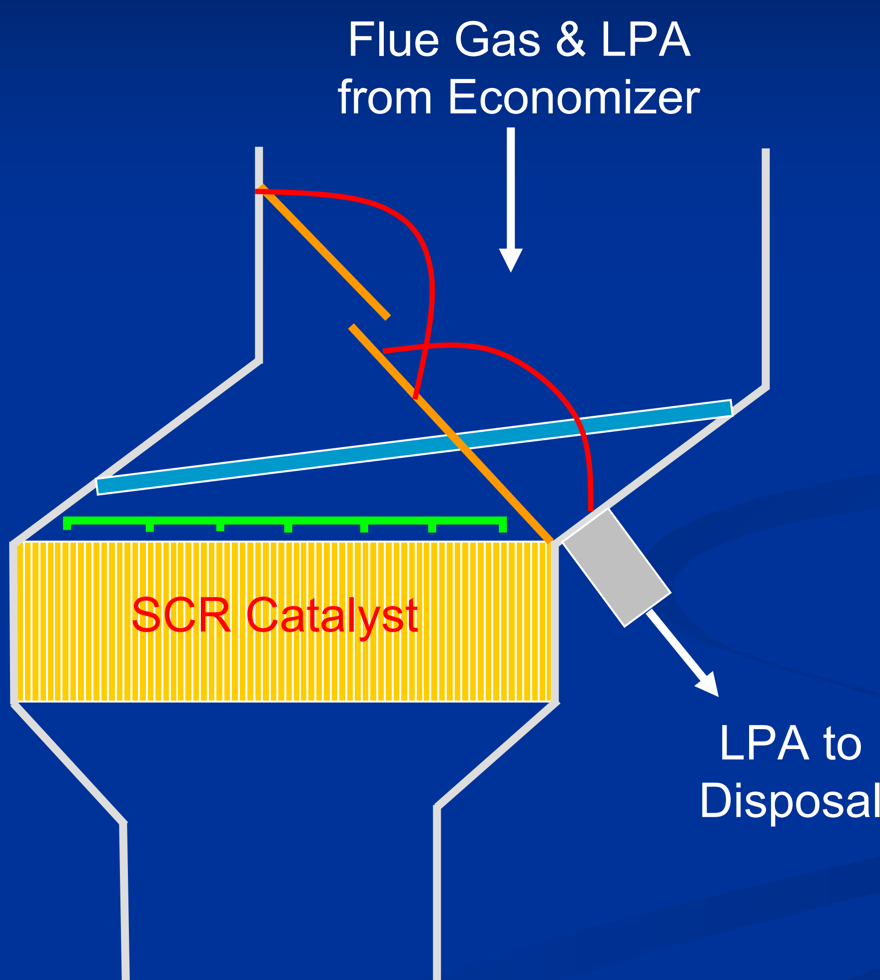
EPA CTM 027, Air Heater Inlet



O&M Experience – Large Particle Ash

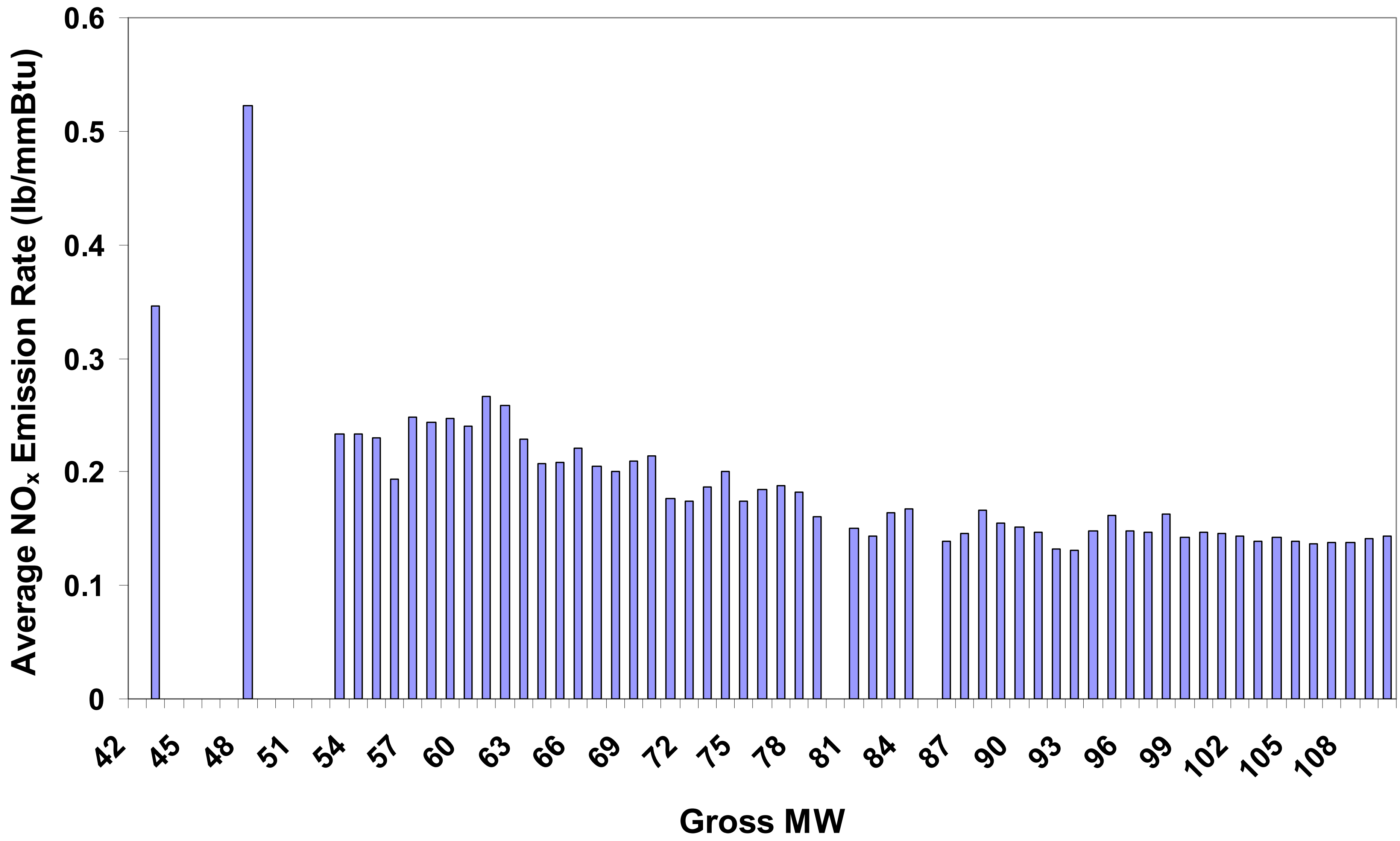
- Decreased NO_x removal efficiency
- Increased urea consumption, ammonia slip
- Increased pressure drop
- Forced outages for catalyst cleaning

O&M Experience – Large Particle Ash
(continued)



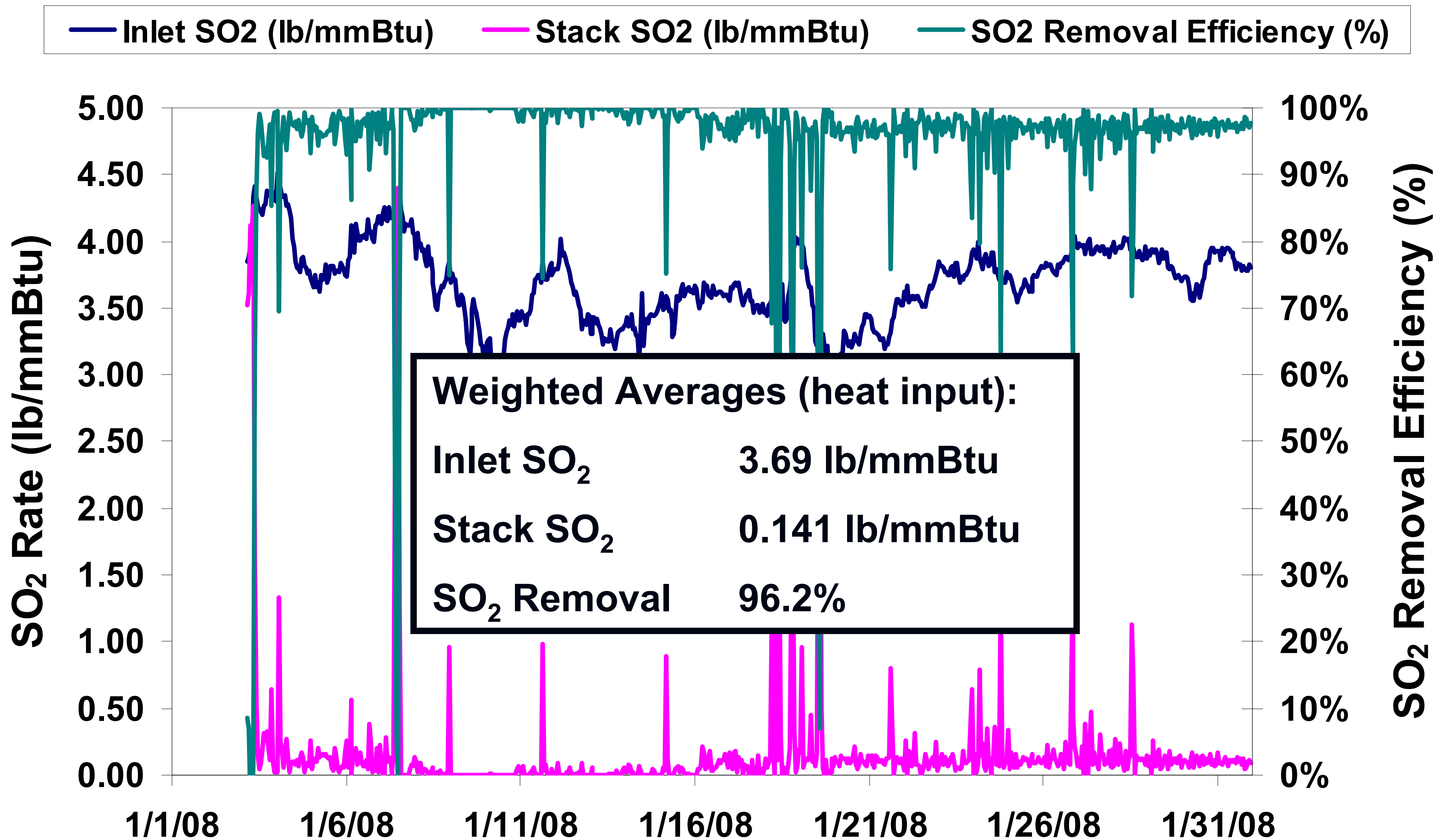
NO_x Emissions vs. Load

January 2008



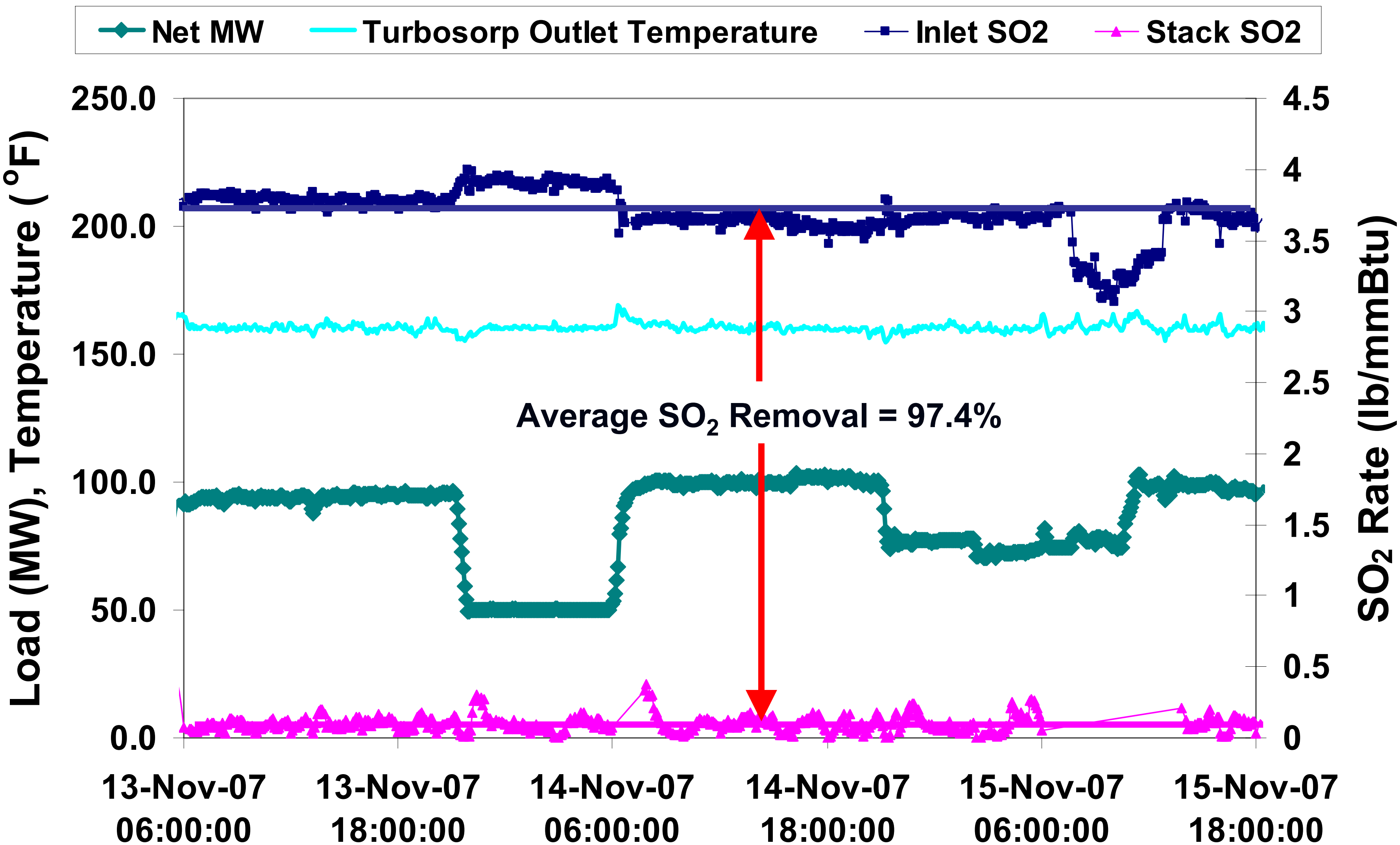
SO_2 Removal Performance

January 2008

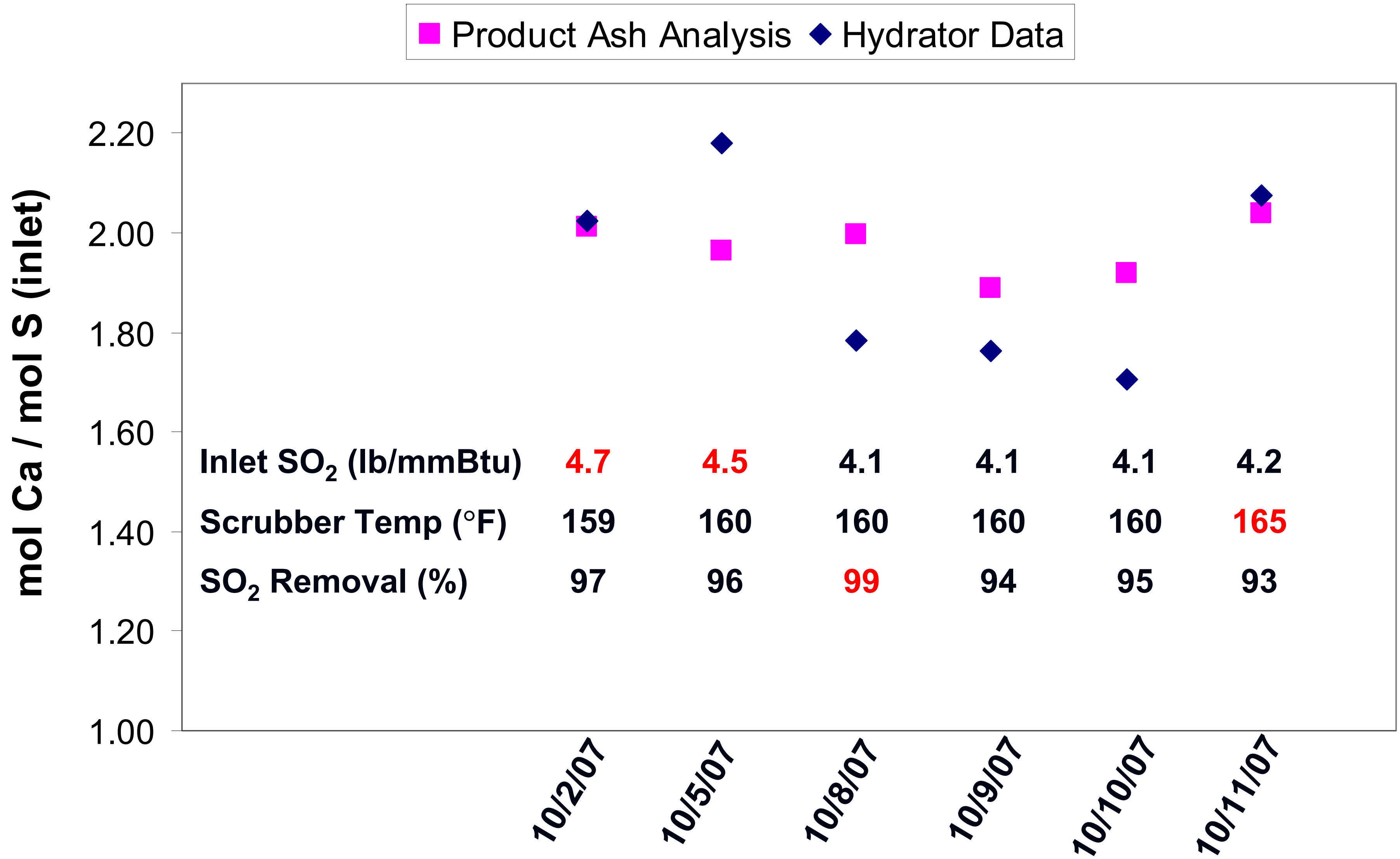


Turbosorp® System

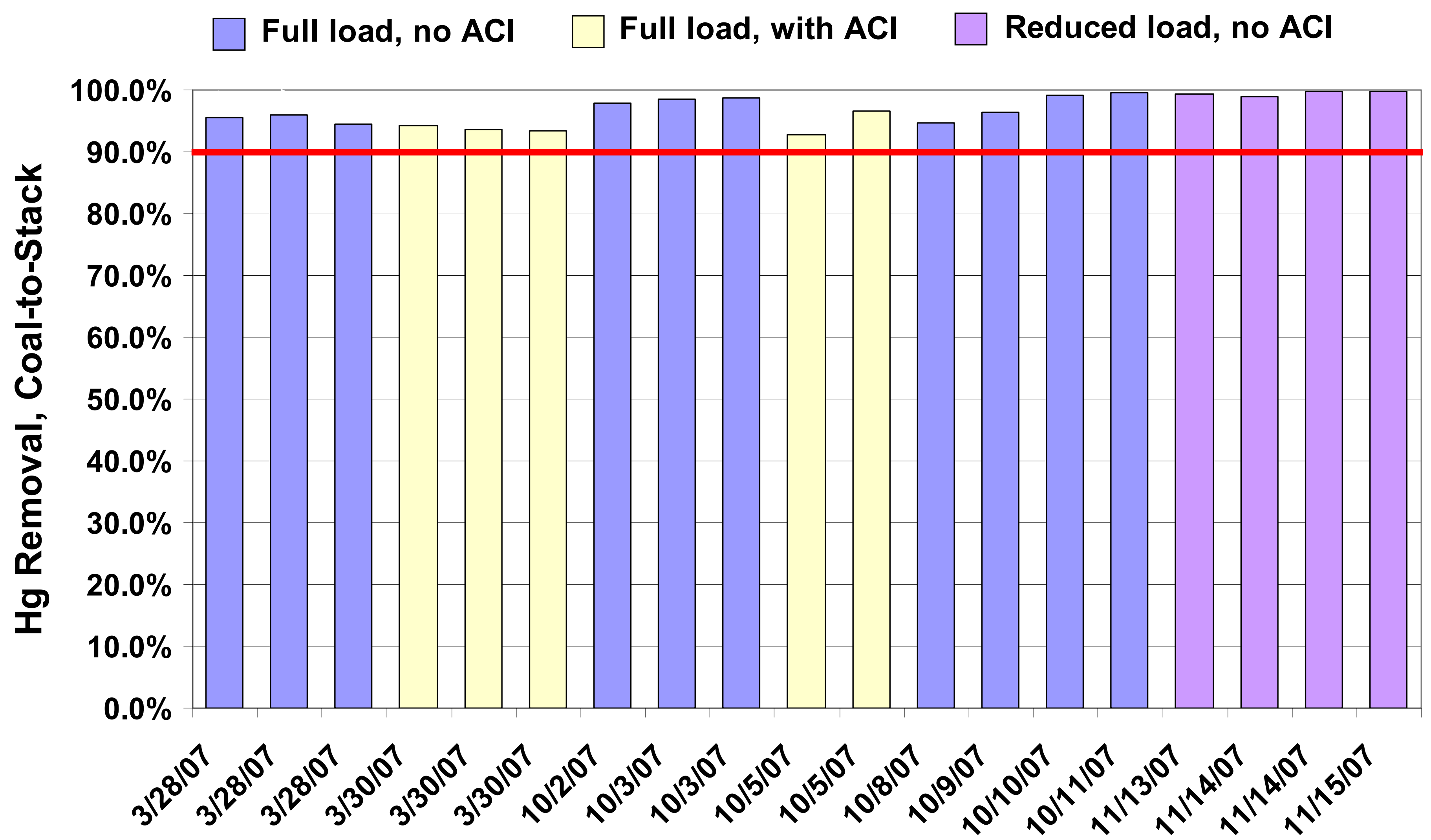
Turndown



Hydrated Lime Utilization
October 2007 Testing



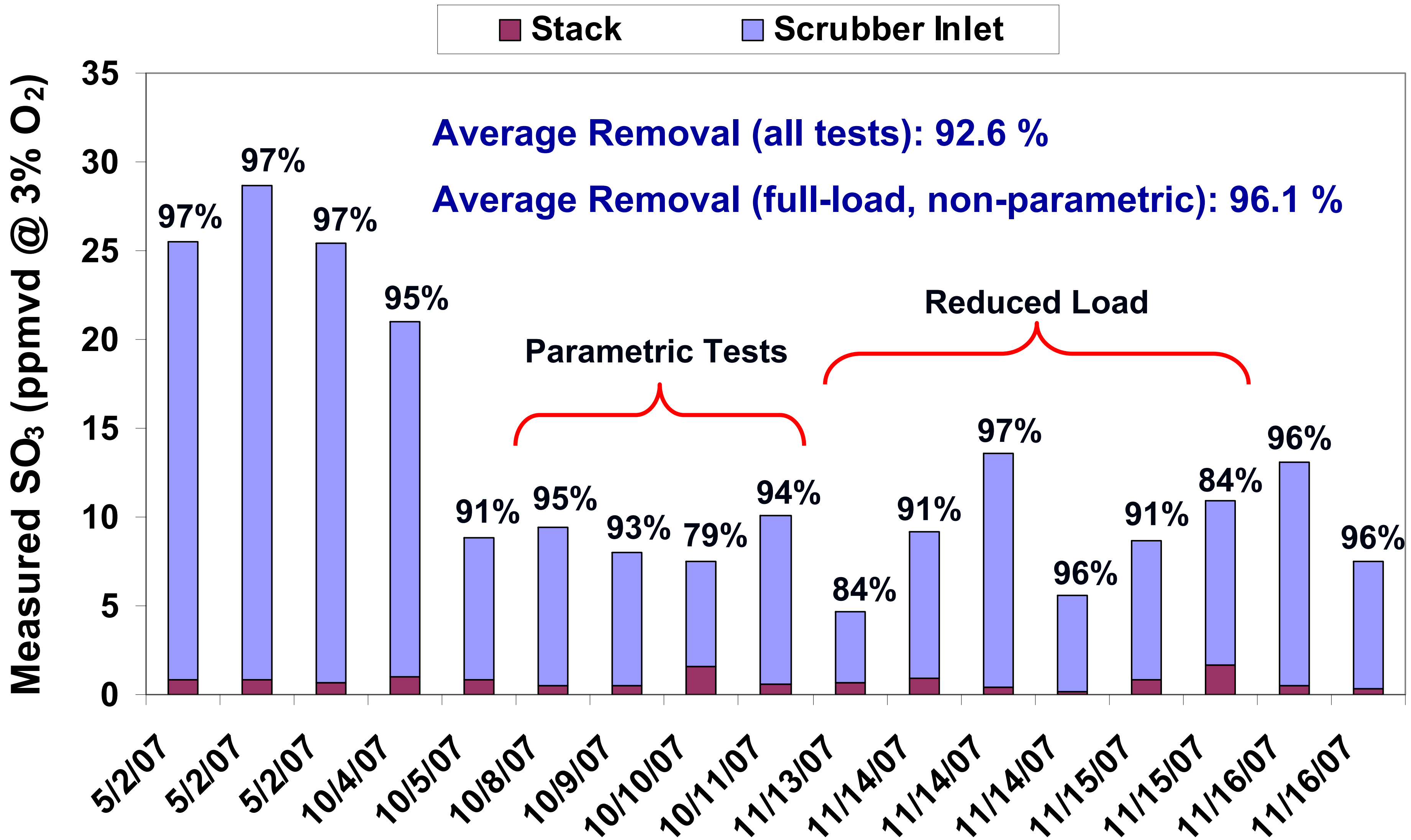
Hg Testing Results
Ontario Hydro Method



Plant Conditions During Hg Tests

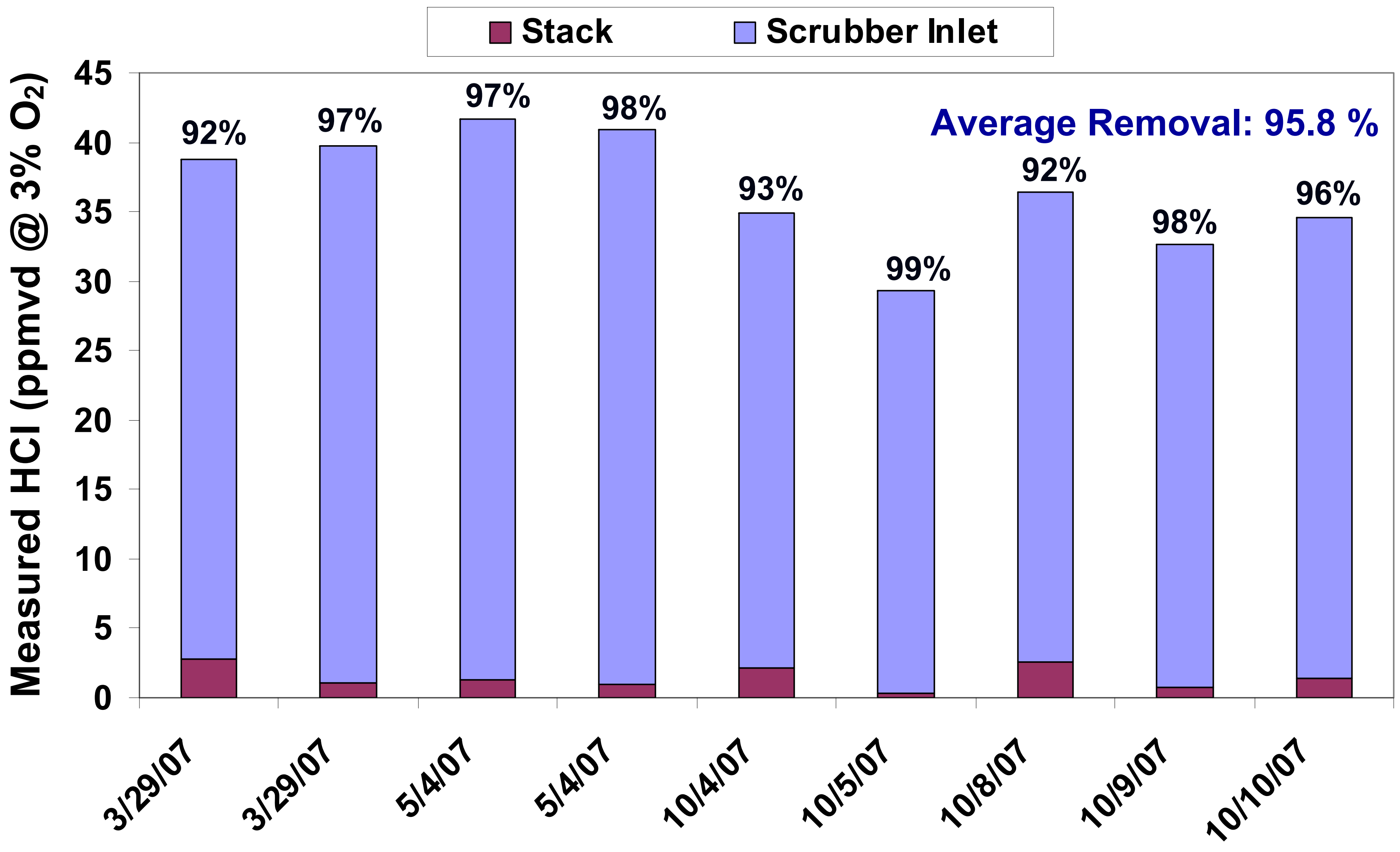
Parameter	Range
Coal Hg content (lb / TBtu)	6.4 – 13.7
Coal S content (lb SO_2 / mmBtu)	3.7 – 4.9
Coal Cl content (wt. %, dry)	0.07 – 0.11
Gross generation (MW)	56.4 – 108.7
Fly ash unburned carbon (%)	9.2 – 25.3
Activated carbon injection rate (lb / mmacf)	0 - 3
SO_2 removal efficiency (%)	92.9 – 99.0
Scrubber outlet temperature (°F)	158.6 – 165.2

SO_3 Testing Results
Controlled Condensation Method



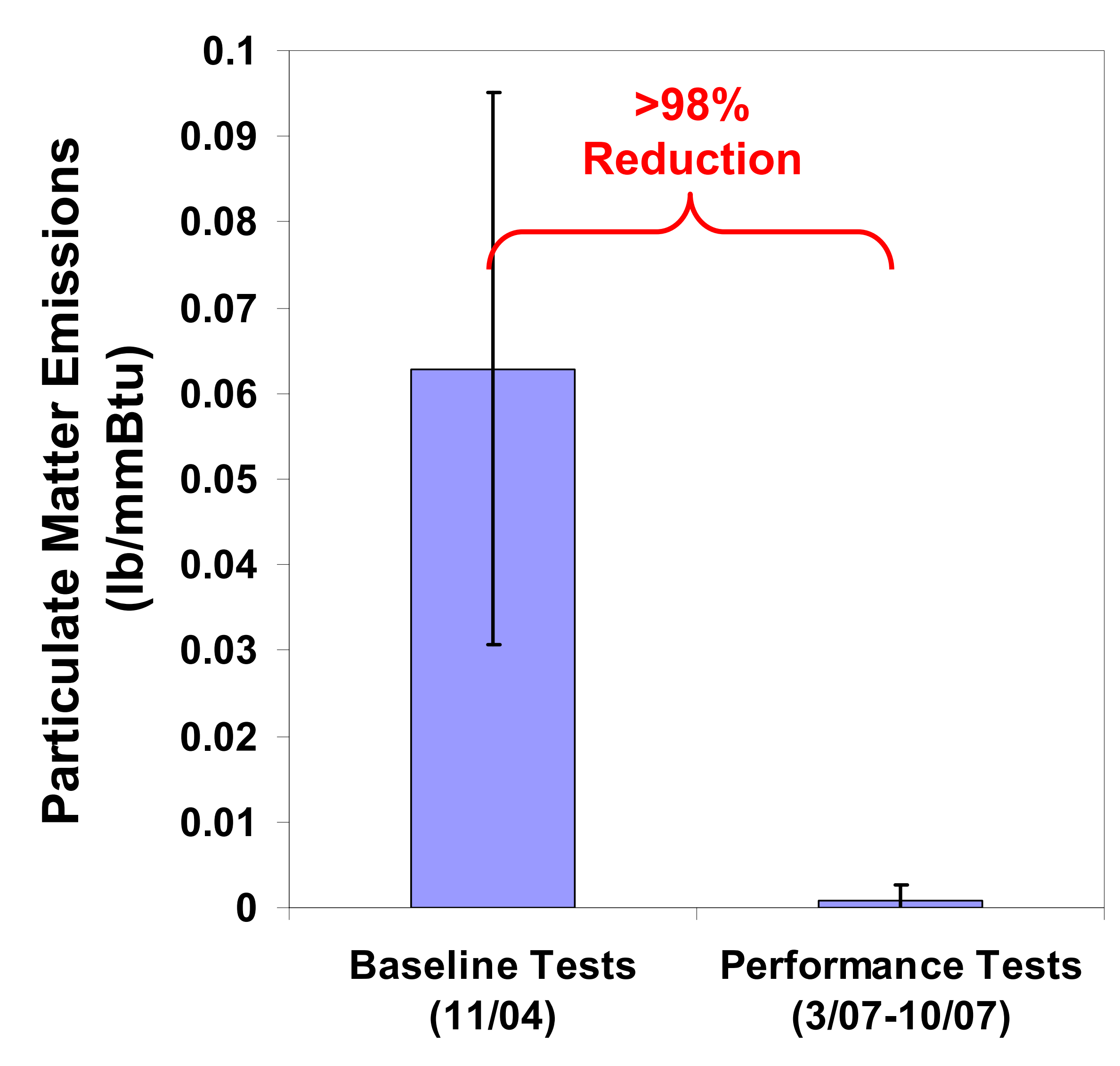
HCl Testing Results

EPA Method 26A



Particulate Testing Results

EPA Method 5/17, Full Load



New baghouse significantly reduces particulate matter emissions relative to old ESP, in spite of increased particle loading from Turbosorp® scrubber

Error bars represent ± 1 standard deviation

Turbosorp® Product Ash

- Similar to spray dryer ash
- Dry powder (~1% moisture)
- Contains $CaSO_3$, $CaSO_4$, fly ash, $CaCO_3$, $Ca(OH)_2$, CaO, $CaCl_2$, CaF_2, inerts
- AES Greenidge sends to landfill (adjacent to plant site)
- Potential uses
  - Mine reclamation
  - Structural / flowable fill
  - Manufactured aggregate
- Leachable Hg (EPA Method 1312) is below detection limit
  - <1.2 % of total Hg in ash (3 samples)

O&M Experience - Turbosorp®

- Lime hydration system
  - Most maintenance-intensive part of Turbosorp® system
  - Can use delivered / stored hydrate to allow offline maintenance
  - Issues encountered to-date
    - Plugging in hydrated lime classifier
    - Water overfed to hydrator
    - Freezing of lines and valves
    - Balls escaped from ball mill
    - Failed bucket elevator shaft
  - Improvements
    - Adjusted classifier rotary feeder to reduce accumulation of fines
    - Modified logic for hydrator water feed
    - Increased onsite hydrate storage capacity

O&M Experience - Turbosorp® (continued)

- Turbosorp® water injection lance
  - Changed about once per week
  - Retrofitted with high pressure quick disconnects
- Ash recycle and disposal system
  - Ash silo vents tend to plug
  - Some problems with freezing / clogging dosing valves
- Baghouse
  - Compressed air demand greater than expected
  - Temporary / permanent compressor capacity added
- No condensation issues encountered in absorber or baghouse

Economics

AES Greenidge Design Case

Constant 2005 Dollars

	EPC Capital Cost ($/kW)	Fixed & Variable O&M Cost ($/MWh)	Total Levelized Cost
NO_x Control	114[a]	1.25	$3,504 / ton NO_2
SO_2 Control	229[b]	6.14	$567 / ton SO_2
Hg Control (incremental)	6	0[c]	$1,567 / lb Hg

[a]Includes combustion modifications, SNCR, in-duct SCR, static mixers, and LPA removal system
[b]Includes scrubber, process water system, lime storage and hydration system, baghouse, ash recirculation system, and booster fan
[c]Based on performance testing results to-date

Assumptions: Plant size = 107 MW net, Capacity factor = 80%, Coal sulfur = 4.0 lb SO_2/mmBtu, SNCR NSR = 1.35, Ca/S = 1.65, 50% Urea = $1.35/gal, Quicklime = $115/ton, Waste disposal = $17/ton, Internal COE = $40/MWh, Plant life = 20 years, Fixed charge factor = 13.05%, AFUDC = 2.35%, Other assumptions based on Greenidge design basis, common cost estimating practices, and market prices

Economics

NO_x Control

	$/MWh	$/ton NO_2 removed
Levelized Capital (TCR)	$2.24	$2,252
Fixed O&M	$0.39	$395
Variable O&M	$0.85	$858
Urea	$0.62	$626
Replacement Catalyst	$0.17	$168
Power/Water	$0.06	$64
Total Levelized Cost	**$3.49**	**$3,504**

- Improved dispatch economics relative to purchasing allowances

Economics

SO_2 Control

	$/MWh	$/ton SO_2 removed
Levelized Capital (TCR)	$4.54	$241
Fixed O&M	$0.88	$47
Variable O&M	$5.26	$279
Lime + Waste Disposal	$4.53	$241
Power/Water	$0.61	$32
Baghouse Bags/Cages	$0.12	$6
Total Levelized Cost	**$10.68**	**$567**

- Improved dispatch economics relative to purchasing allowances
- Hg, acid gas, and improved primary particulate control for "free"

Summary

- Greenidge MPC process uniquely designed to meet needs of smaller coal-fired units
  - Deep emission reductions
  - Low capital costs
  - Small space requirements
  - Applicability to high-sulfur coals
  - Low maintenance requirements
  - Operational flexibility
  - Improved dispatch economics

- Performance testing results to-date are generally encouraging
  - Demonstrated attainment of performance guarantees for NO_x, SO_2, Hg, and acid gases
  - SO_2 removal efficiencies >95% routinely achieved
  - All tests have shown >90% Hg capture without ACI
  - Particulate matter emissions significantly reduced

Summary

- O&M challenges thus far
  - Large particle ash plugging in-duct SCR catalyst
  - Difficult to attain 0.10 lb/mmBtu NO_x emissions while maintaining good combustion, low ammonia slip
  - Lime hydration system is rather maintenance intensive

- Additional testing planned through summer 2008
  - Reduced load testing
  - Parametric scrubber testing
  - Follow-up testing

Disclaimer