REINHOLD ENVIRONMENTAL Ltd.

2019 REINHOLD Round Table
Presentation

June 24 & 25, 2019, in Birmingham, Alabama / Hosted by Southern Company

Acid Gas Control – Redefining Cultural Practices in Unit Flexibility to Compete in a Changing Environment

Chad Donner / Cal Lockert – Reinhold Roundtable June 24th, 2019

Introduction

Current DSI System Status

Future DSI System Considerations

Questions

Overview

Background

Sorbent Injection Strategic Approach

Changing Generation Environment

Introduction

Background

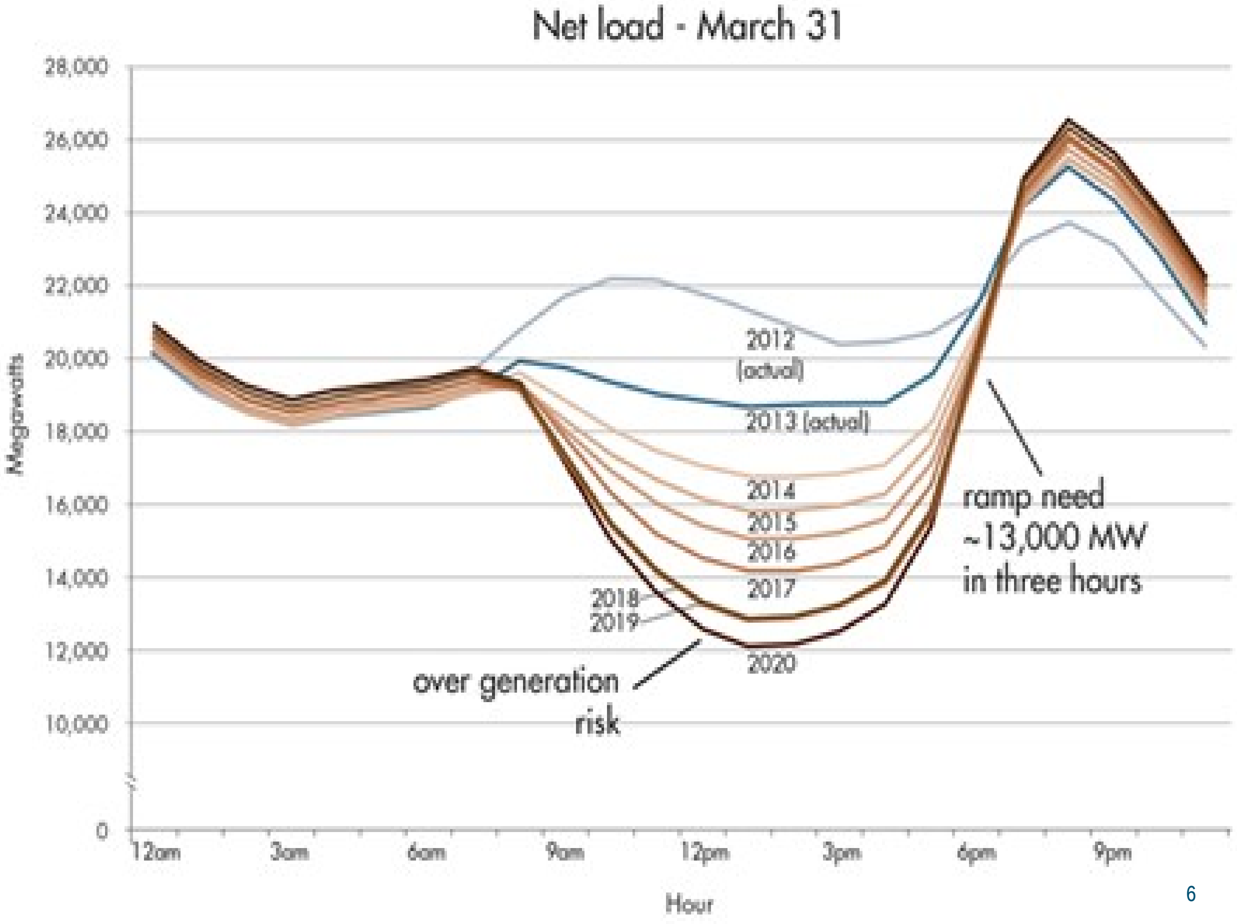
- Duke Energy has had significant experience with Sorbent Injection since 1999 and have learned from the school of hard knocks and the industry was not developed to what it is today
- The DSI industry has come a long way since 1st and 2nd generation systems and Duke Energy has been heavily involved in developing the most recent 3rd generation DSI systems that are now in service and operating reliably with high performance
- The entire DSI process can be thought of as a chemical process where the 3 T's (Time, temp, turbulence) are applicable to many areas throughout the system
- As opportunities arise to improve performance of existing systems, lessons learned from the broader fleet can be applied
- Not as simple as "Just get it in the duct"

Sorbent Injection Strategic Approach

- “Everything effects SO_3 and SO_3 effects everything”
  - Boiler/SCR SO_2 Oxidation, O_2%, SCR MOT, NOx Removal, ABS Formation/AH Pluggage, Heat Rate, HCl Removal, Mercury Capture, Precipitator Performance, FGD, Blue Plume
  - Quantifying all benefits of Heat Rate improvement, less coal, less ash, less landfill, credits etc…
  - No DSI requirements…hmmm…
- Sorbent Injection systems need to be thought of as an integrated control technology not just a Sorbent Injection System as they have potential to impact the entire plant both positively and negatively.
  - Siloed vs. Holistic
- Past sorbent injection systems have fallen short on effective means of control and long term reliability
  - As plants begin rely on these systems in order to operate they need to be reliable and the new 3rd Generation systems have proven to be reliable with availability greater than 99%
  - 3rd Generation systems have much better controls that greatly reduce the amount of daily operator involvement in system operation from feedrate controls to system monitoring

Changing Generation Environment

- Why???
  - Solar and wind have created large amounts of peak generation that are a priority take and significantly changed the generation load profile
  - Coal must now load follow to a degree and be more nimble for turndown and ramp rate
  - New Ozone season limits will require pushing the SCR's harder and keeping them in service longer



What Have We Done

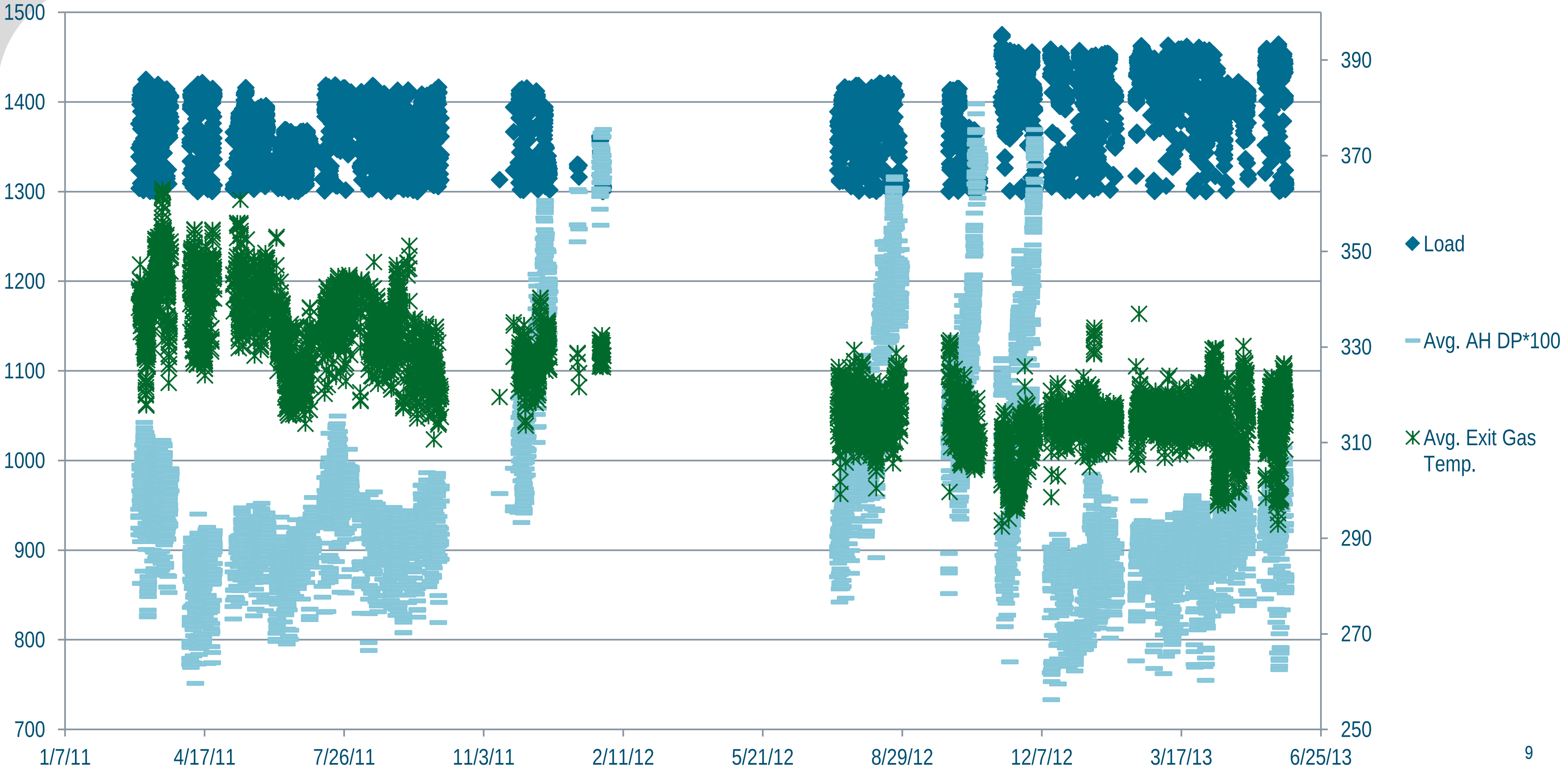
Current DSI System Status

We Have Figured Out How to Solve Blue Plume

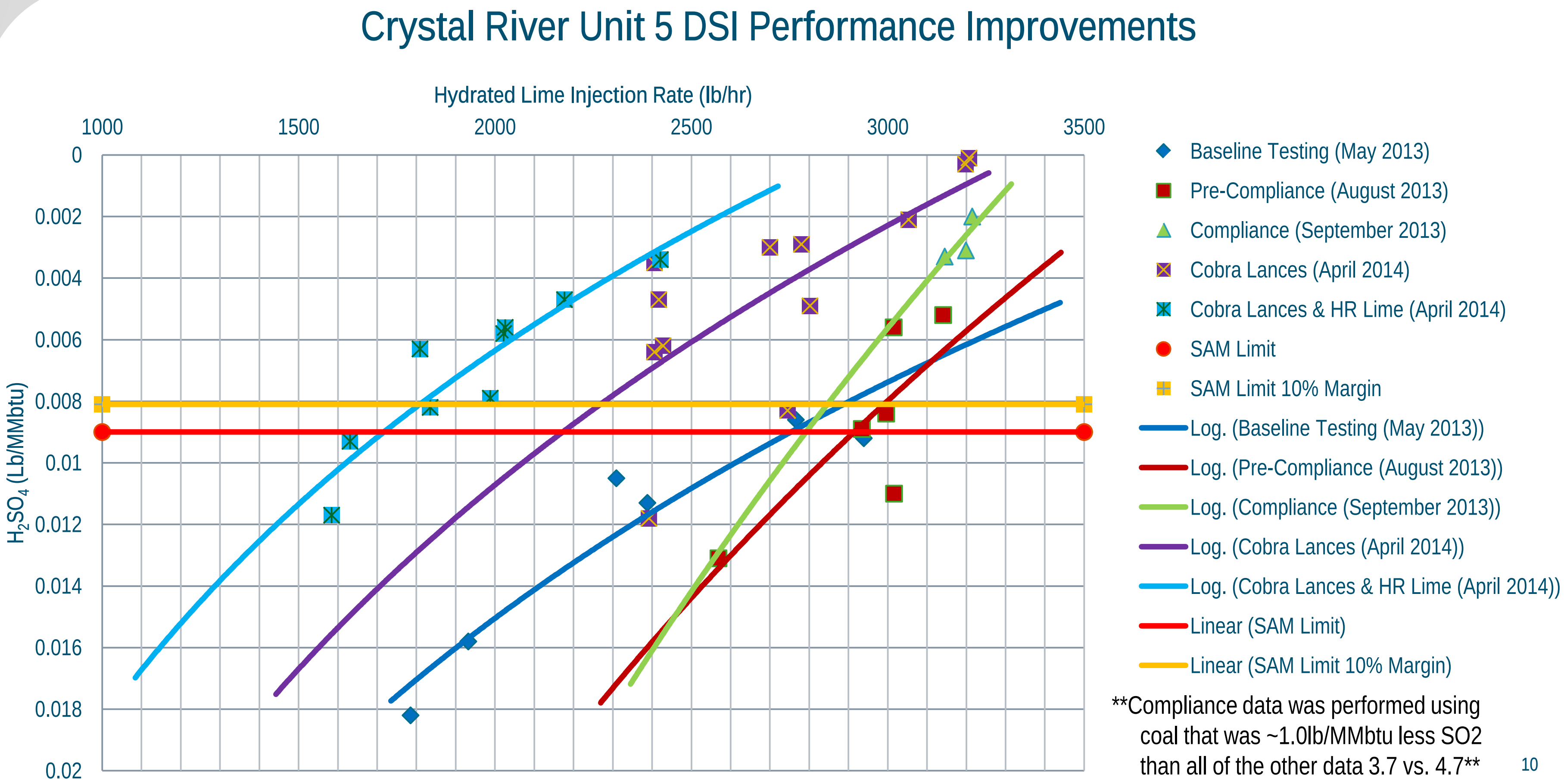
- Pre SCR / No DSI, 5.0 lb/MMBTU SO_2 Coal

- Post SCR / DSI, 2 Layers, no Ammonia, 5.0 lb/Mmbtu SO_2 Coal, Mass Ratios ~3.25 lb Hydrate / Lb SO_3

We Have Figured Out How to Solve Air Heater Pluggage

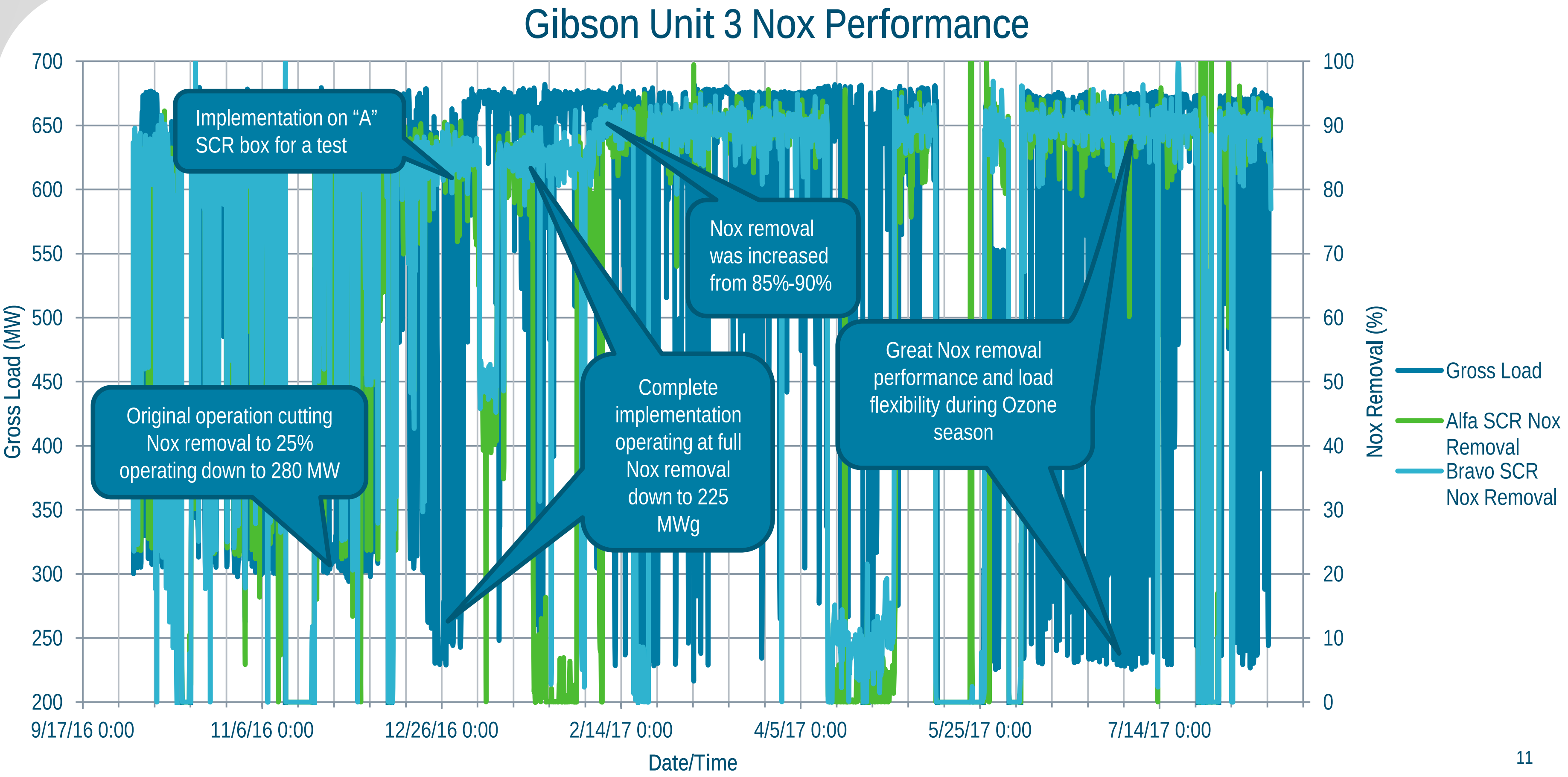


We Have Figured Out How to Squeeze More Performance From Our Systems



Compliance data was performed using coal that was ~1.0lb/MMbtu less SO2 than all of the other data 3.7 vs. 4.7

We Have Figured Out How to Keep SCR’s Operating at Lower Loads



Implementation on “A” SCR box for a test

Nox removal was increased from 85%-90%

Original operation cutting Nox removal to 25% operating down to 280 MW

Complete implementation operating at full Nox removal down to 225 MWg

Great Nox removal performance and load flexibility during Ozone season

We Have Figured Out How to Convey Hydrated Lime Reliably

- JACKPOT!!!

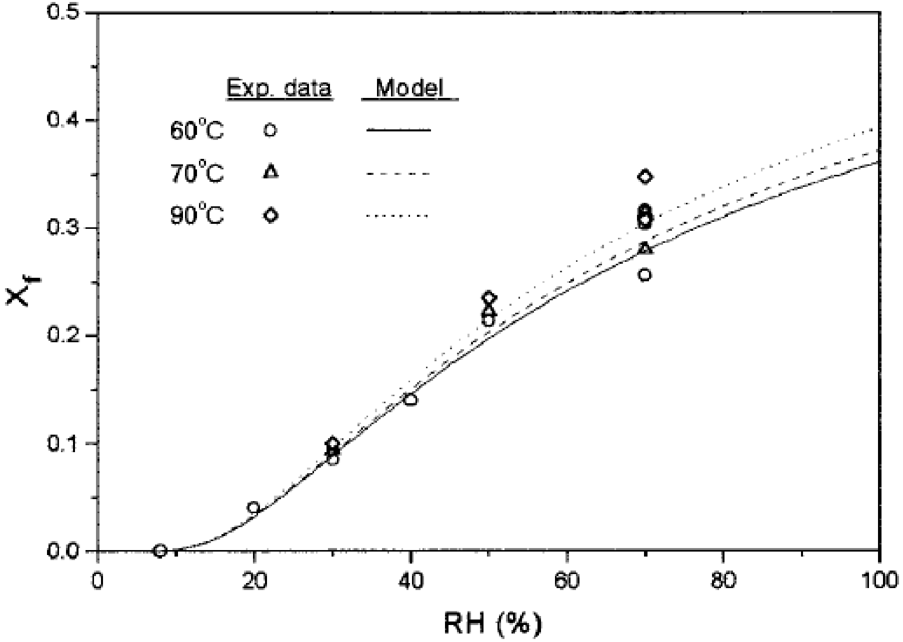
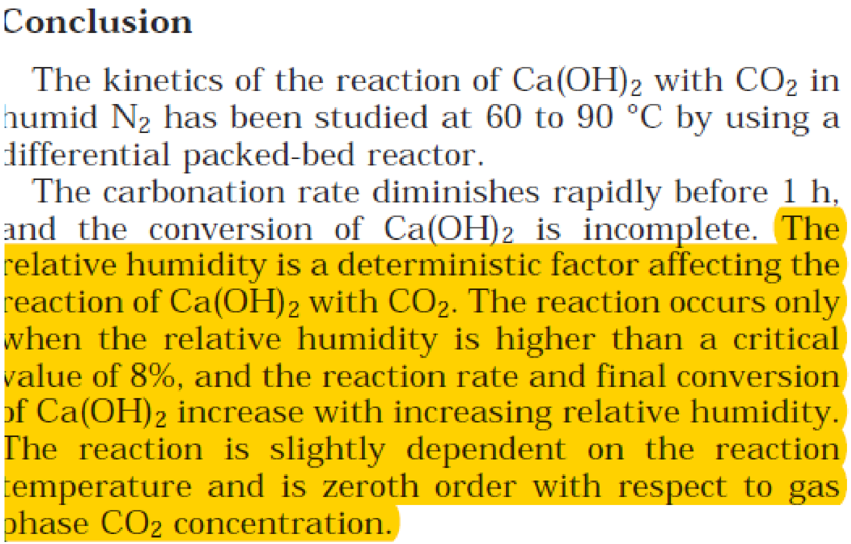


Figure 5. Final conversion for the carbonation of $Ca(OH)_2$. The curves represent the results calculated by using eqs 8a and 16.

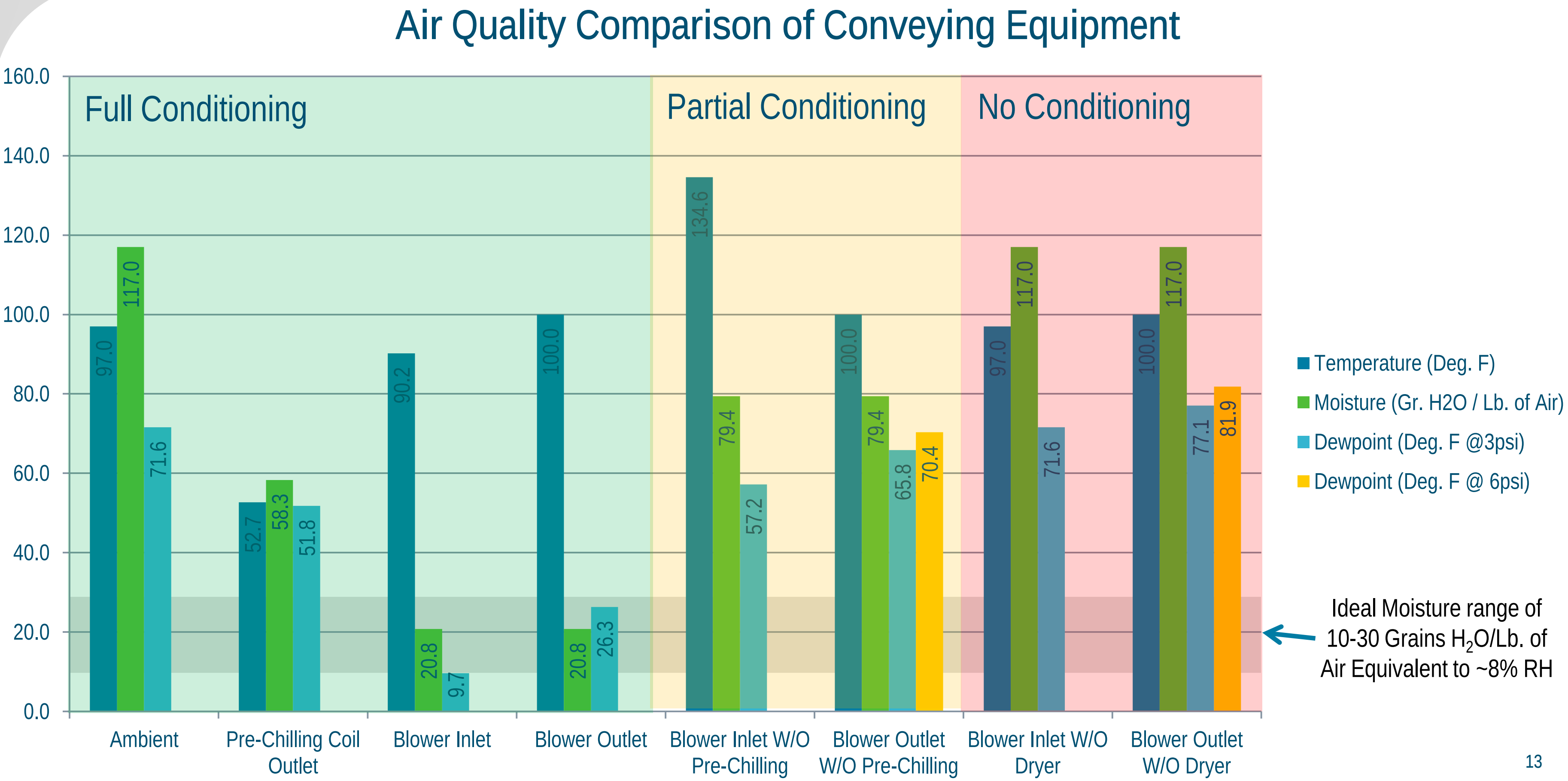


Conclusion

The kinetics of the reaction of $Ca(OH)_2$ with CO_2 in humid N_2 has been studied at 60 to 90 °C by using a ifferential packed-bed reactor.

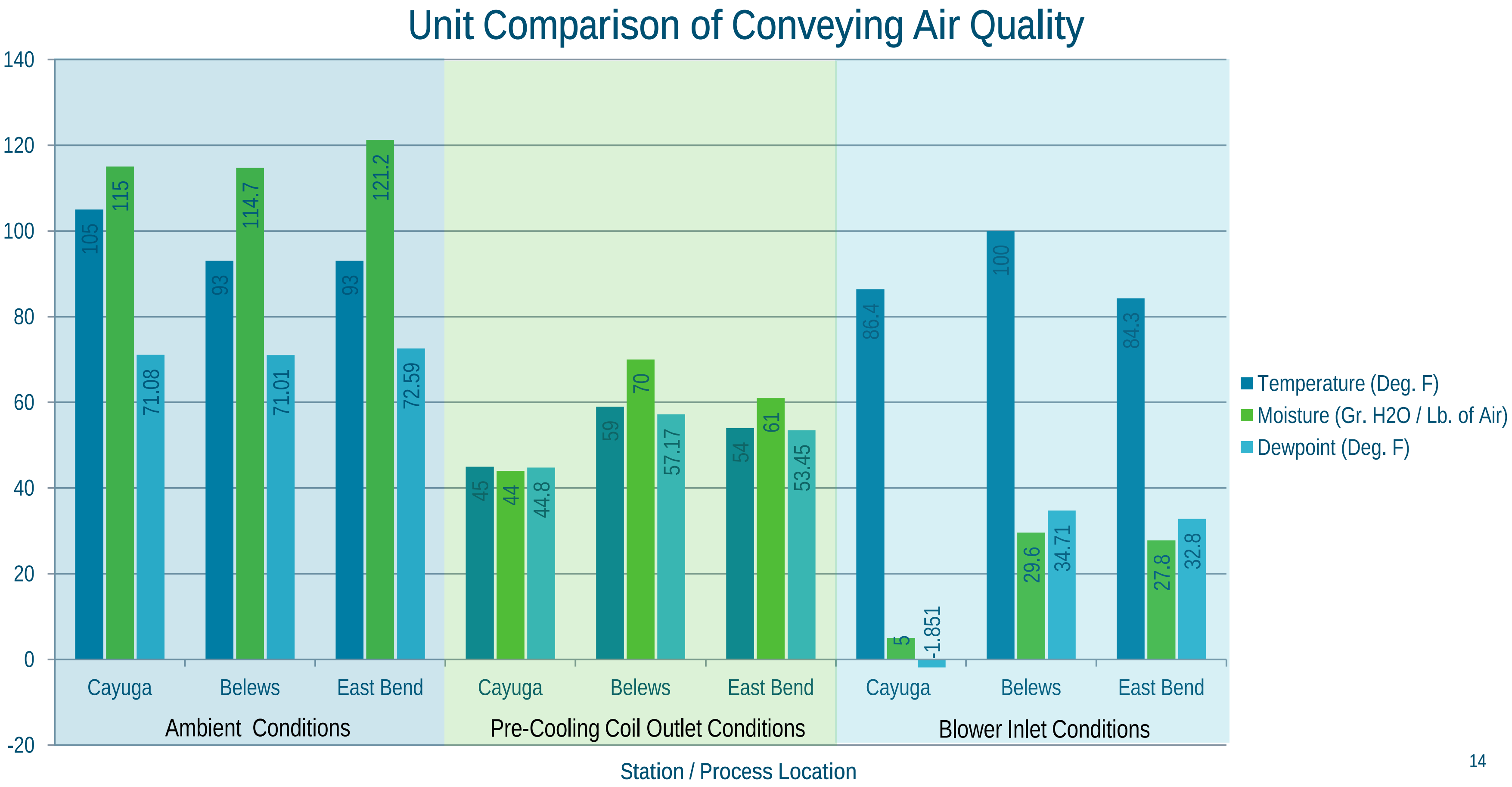
The carbonation rate diminishes rapidly before 1 h, and the conversion of $Ca(OH)_2$ is incomplete. The elative humidity is a deterministic factor affecting the eaction of $Ca(OH)_2$ with CO_2. The reaction occurs only when the relative humidity is higher than a critical value of 8%, and the reaction rate and final conversion of $Ca(OH)_2$ increase with increasing relative humidity. The reaction is slightly dependent on the reaction emperature and is zeroth order with respect to gas phase CO_2 concentration.

We Have Figured Out How to Convey Hydrated Lime Reliably



Ideal Moisture range of 10-30 Grains H_2O/Lb. of Air Equivalent to ~8% RH

We Have Figured Out How to Convey Hydrated Lime Reliably



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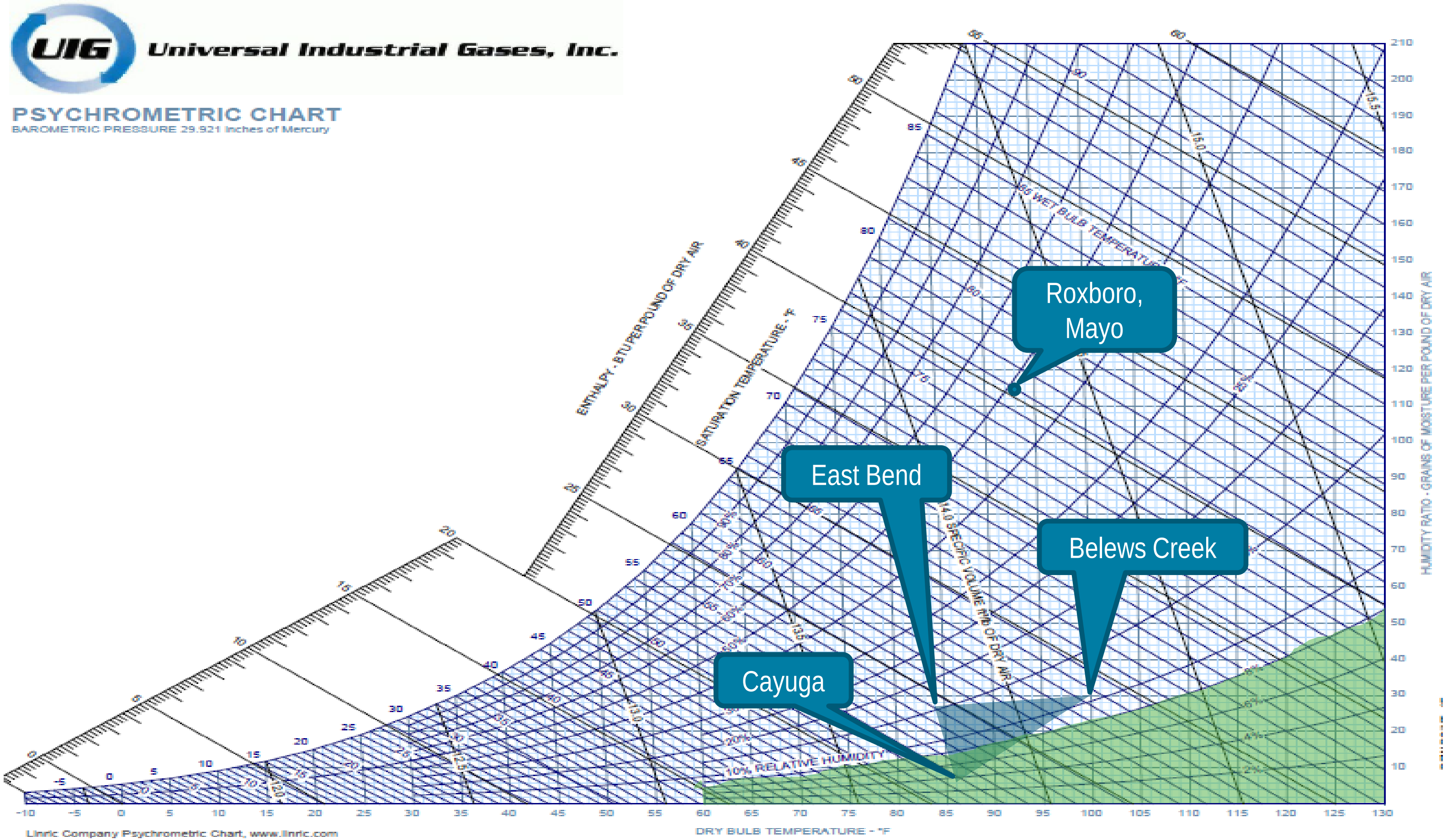


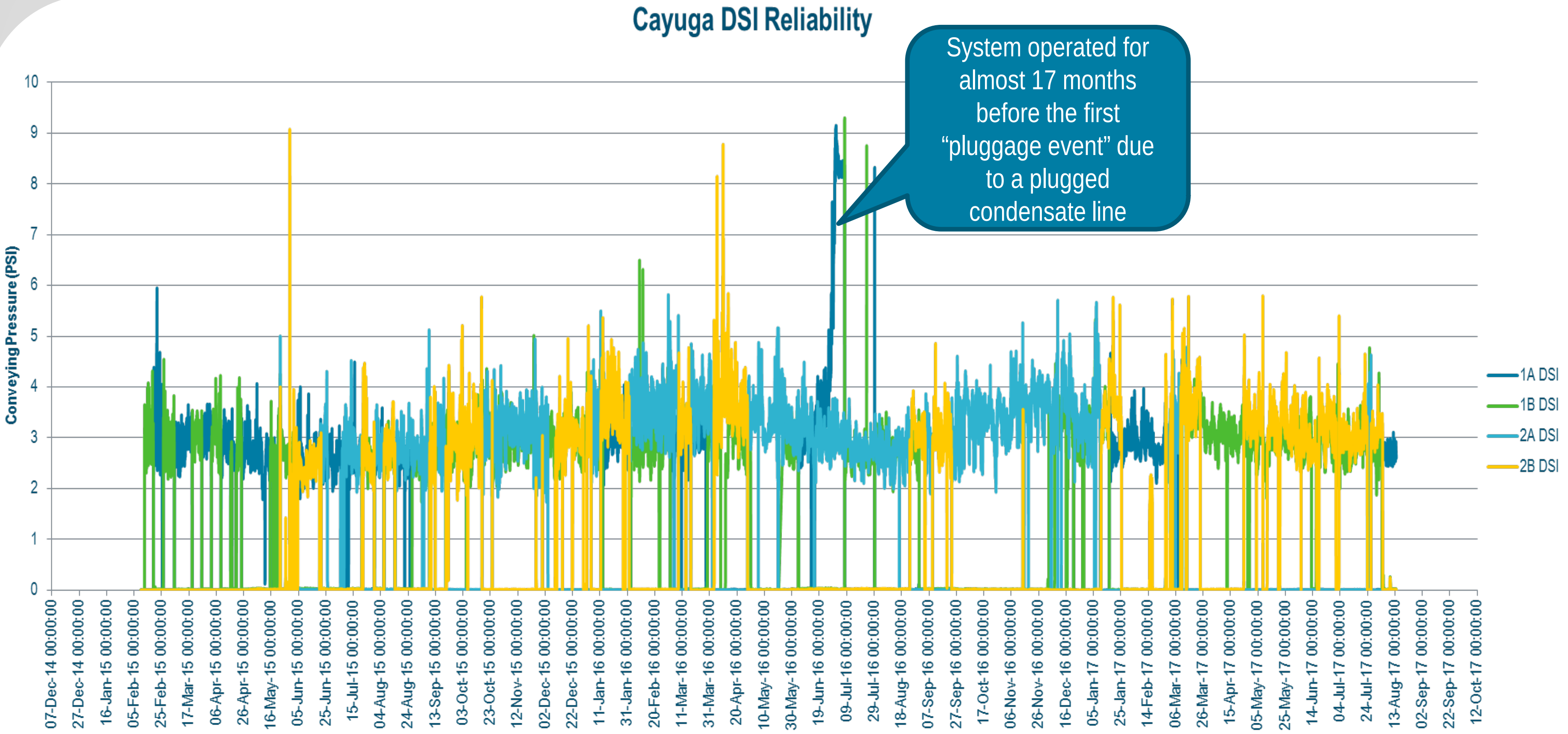
Roxboro, Mayo

East Bend

Belews Creek

Cayuga

We Have Figured Out How to Convey Hydrated Lime Reliably


Cayuga DSI Reliability

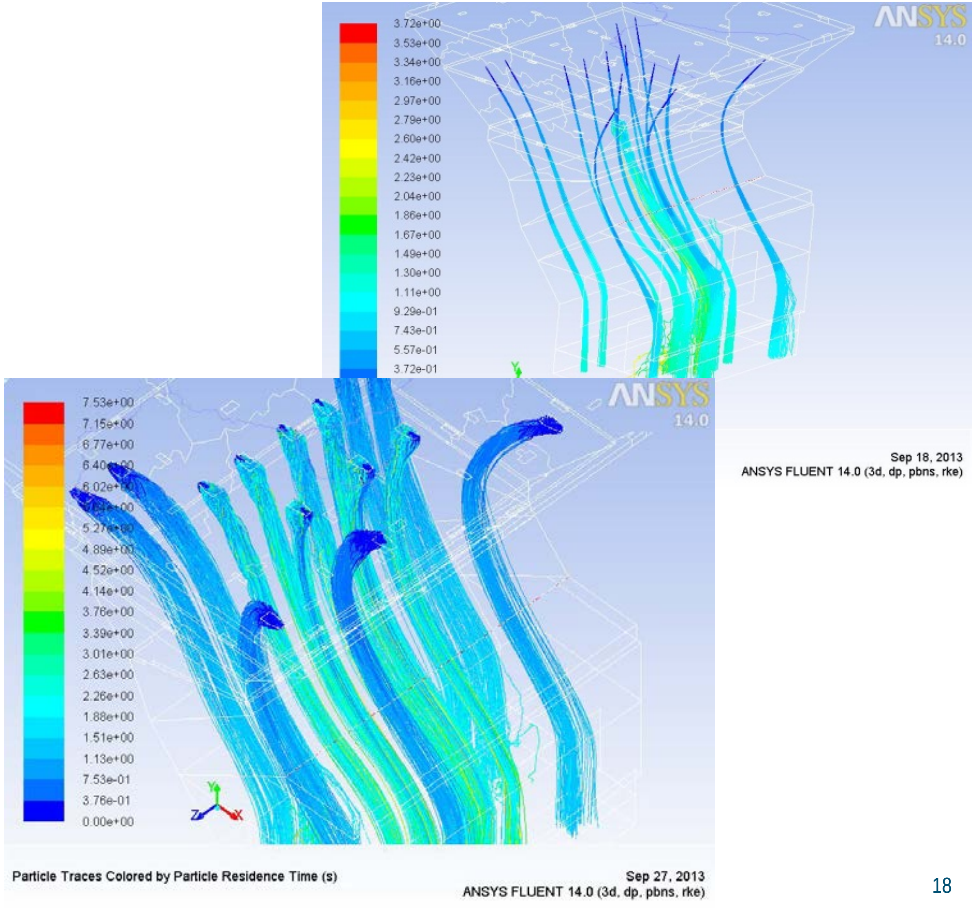
System operated for almost 17 months before the first “pluggage event” due to a plugged condensate line

What We Need to Do

Future DSI System Considerations

What We Need to Do

- More often than not CFD modeling is only looked at for full load conditions
- Performance needs to be optimized at low loads just as it has for full load
- Variable injection grids should be investigated to optimize low load performance while maintaining performance at full loads
- Technologies that provide the ability to help keep ash and reagent/sorbent entrained with provide a positive benefit
- DSI system controls need to be further developed to improve the turndown capability and response
- Realtime performance monitoring needs to continue to develop for reagent optimization and control



Sep 18, 2013
ANSYS FLUENT 14.0 (3d, dp, pbns, rke)

Particle Traces Colored by Particle Residence Time (s)

Sep 27, 2013
ANSYS FLUENT 14.0 (3d, dp, pbns, rke)

What We Need to Do

- Result of unit run consistently at low load

What Do We Do Next?

REDEFINING CULTURAL PRACTICES FOR UNIT FLEXIBILITY

MISSISIPPI LIME

DISCOVERING WHAT'S POSSIBLE WITH CALCIUM

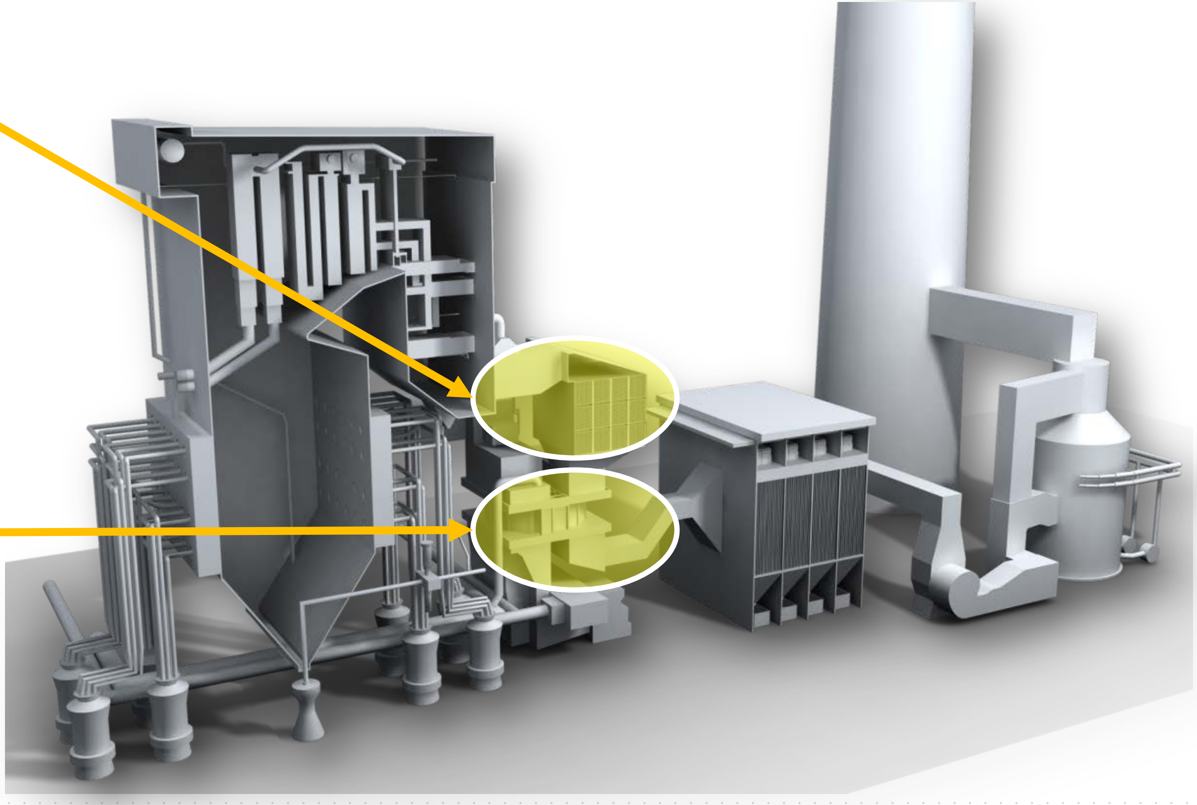
June 24, 2019 – Reinhold/Birmingham

The Impact of DSI on Unit Flexibility

What stops the Unit from Achieving the Flexibility Goals from Turndown and Outlet Gas Temperature Objectives

Let’s accept that DSI can eliminate SCR MOT constraints

Let’s also accept that DSI can eliminate air heater differential pressure issues without auxiliary heating from steam coils or bypass dampers



Changing Plant Culture is a Deliberate Process

More Operating Hours & Improved Value

Slow Decline to Closure

We Must Adapt to the New Order of Generation

YOU ARE NOT THE FIRST TO TRAVEL INTO UNKNOWN WATERS

Some Case Histories in Selected Process Improvements

Roxboro Plant


www.americanaerialphotos.com

ROXBORO PLANT
12-12-08

- **Location**
  Semora, North Carolina
- **Commercial Operation Dates**
  Operations began in 1966 with additions in 1968, 1973, and 1980
- **Size**
  2,460 MWs Net (Four Units – 380 MWs, 671 MWs, 698 MW's, and 711 MWs)
- **Notable**
  - At full-load conditions, plant burns over 20,000 tons of coal per day (200 rail cars)
  - Cooling water from Hyco Lake (4400 Acres including afterbay)

Past Plant Performance Data when Roxboro was more base loaded

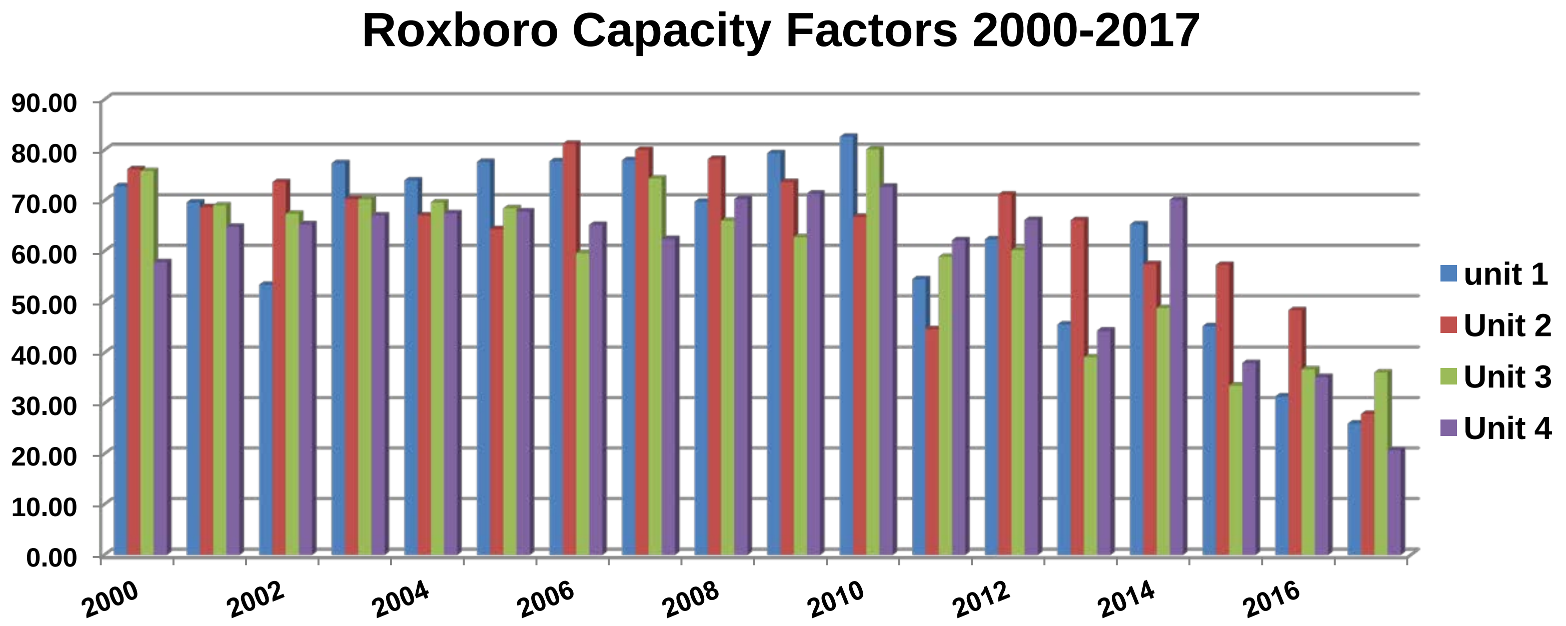
- **Operational Performance**
  - Top Quartile Operational Performance
    - Commercial Availability – **88.55%** (Five year Average)
    - Forced Outage Rate (EFOR) – **1.57%** (Five year Average)
- **Fuel Flexibility/Efficiency Improvements**
  - Through a series of testing and capital improvements, have added NAPP, ILB, and low quality (low BTU/high ash) coals to portfolio.
    - Resulting fuel savings: >**$100M since 2010**
  - Boiler fan VFD efficiency improvement projects have reduced Auxiliary Loading by an average of **10.5 MW’s** (more MW’s available for sale)

Fast Forward to present day

- Units are being cycled and staying off line for long periods of time during the spring and fall seasons.
- Roxboro being a base loaded station for all these years suddenly finds ourselves figuring out how to properly lay up boilers and other unit sub systems

Roxboro plant (The Rock) has a long history of carrying the load which made the transition to lower CFs and unit cycling somewhat difficult to adjust to, ***what could we do to stay in the conversation! we couldn’t just wait without at least exploring our options and knowing what our limits were***. Although the above data is a couple years old wanted to pass along some of what this station has done over the years, the glory years if you will.

Roxboro Capacity Factors

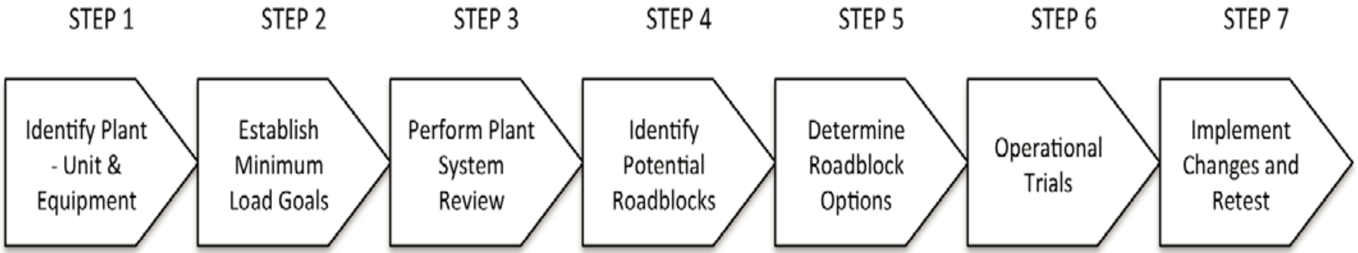


- Changes in load profiles with the increased renewables penetration
- What can Roxboro Plant do in order to make us more flexible ?

Lets see what we can do at the plant level to provide more unit flexibility and run more even at lower capacity factors

- Is there precedent for this type operation ?
- Contact corporate engineering and ask for help interpreting the data as we begin to test
- WE DON’T KNOW WHAT WE DON’T KNOW

- The objectives for the test are to try and ***establish a lower and sustainable minimum load for each unit while not exceeding any design limitations and while not exceeding any emissions limits or annual targets***. In order to accomplish the objectives, steps would be developed and tests performed systematically to ensure limits are identified and known.
- EPRI has tools developed that can assist with the development of a test plan as shown below in the illustration.

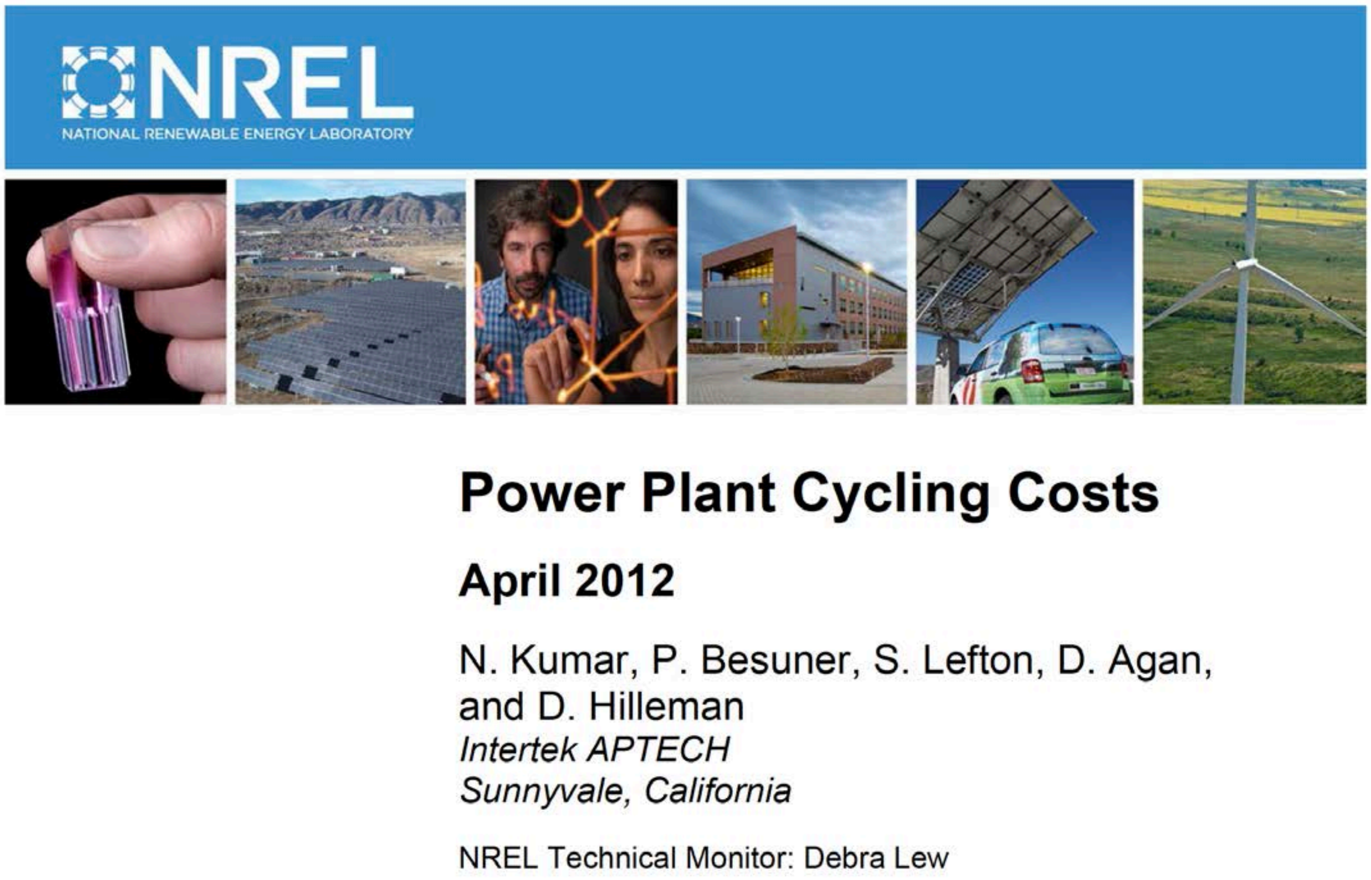


Is it worth the Effort

- Corporate Model was run
- Rox 1&2 ***additional 200-500 service hours***
- Rox ***generation decreases about 125 GWHR*** with units running at lower avg. load
- Lower Roxboro generation makes room for DEP CCs to run more
- **Total System Cost Decreases $2-3 M**
- Overall conclusion: As modeled, the lower Roxboro min loads predominantly provide system economic value by shifting total energy from higher cost units to lower cost units (CCs) but as interpreted from previous modeling they provide only a small benefit toward accommodating solar
- Based on cost decrease and additional service hrs. the benefits seems encouraging and testing began

SEGUE #1 – CYCLING COSTS & MIN LOAD REDUCTION BENEFITS

Outside Analysis of Cycling Costs



NREL
NATIONAL RENEWABLE ENERGY LABORATORY

Power Plant Cycling Costs

April 2012

N. Kumar, P. Besuner, S. Lefton, D. Agan,
and D. Hilleman
Intertek APTECH
Sunnyvale, California

NREL Technical Monitor: Debra Lew

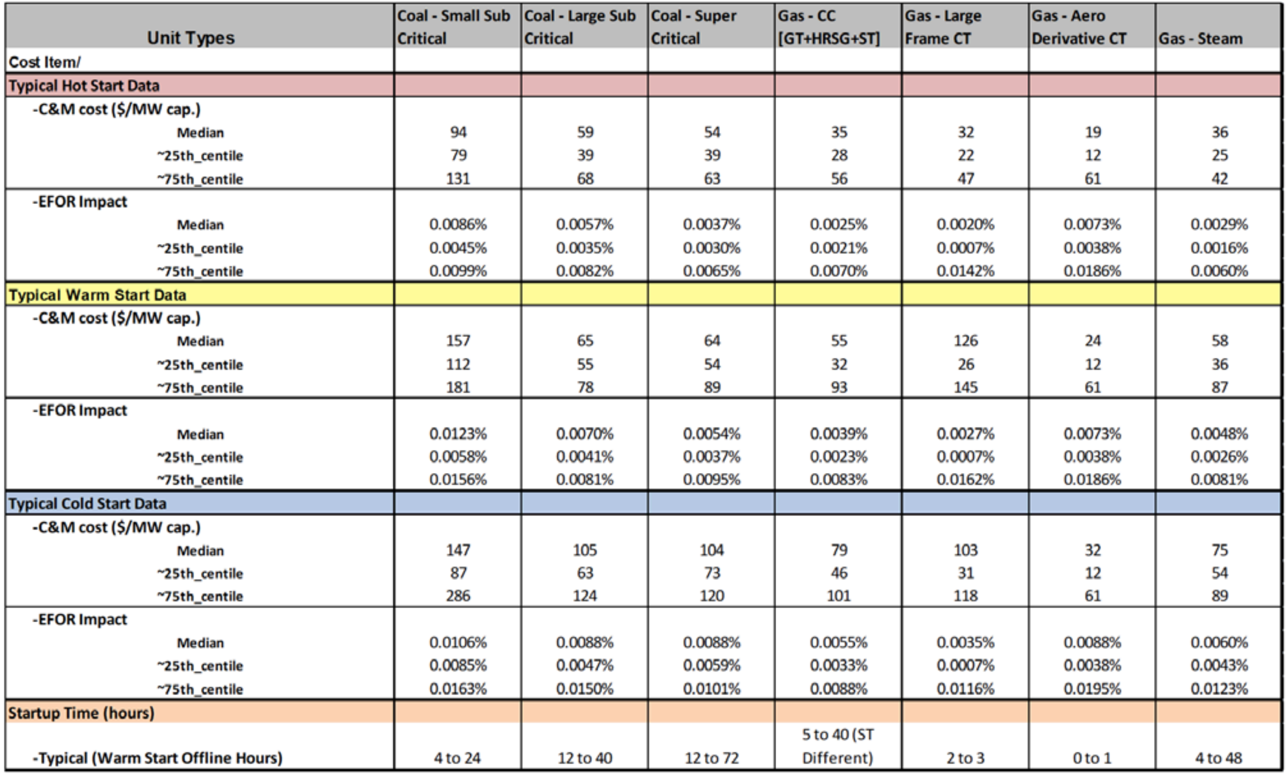
Cost of Cycling

There are multiple factors that combine to reflect the total "cost" of cycling a Unit:

1. **Increases in maintenance, operation (excluding fixed costs), and overhaul capital expenditures**
2. **Cost of heat rate changes due to low load and variable operation**
3. **Cost of startup fuel, auxiliary power, chemicals, and extra manpower for startups**
4. **Cost of long term heat rate increases (i.e., efficiency loss)**
5. **Long-term generation capacity cost increases due to unit life shortening**

Capital & Maintenance Cost/EFOR Impact

Table 1-1: Typical lower bound costs of cycling and other data for various generation types



Unit Types	Coal - Small Sub Critical	Coal - Large Sub Critical	Coal - Super Critical	Gas - CC [GT+HRSG+ST]	Gas - Large Frame CT	Gas - Aero Derivative CT	Gas - Steam
Cost Item/							
Typical Hot Start Data							
-C&M cost ($/MW cap.)							
Median	94	59	54	35	32	19	36
~25th_centile	79	39	39	28	22	12	25
~75th_centile	131	68	63	56	47	61	42
-EFOR Impact							
Median	0.0086%	0.0057%	0.0037%	0.0025%	0.0020%	0.0073%	0.0029%
~25th_centile	0.0045%	0.0035%	0.0030%	0.0021%	0.0007%	0.0038%	0.0016%
~75th_centile	0.0099%	0.0082%	0.0065%	0.0070%	0.0142%	0.0186%	0.0060%
Typical Warm Start Data							
-C&M cost ($/MW cap.)							
Median	157	65	64	55	126	24	58
~25th_centile	112	55	54	32	26	12	36
~75th_centile	181	78	89	93	145	61	87
-EFOR Impact							
Median	0.0123%	0.0070%	0.0054%	0.0039%	0.0027%	0.0073%	0.0048%
~25th_centile	0.0058%	0.0041%	0.0037%	0.0023%	0.0007%	0.0038%	0.0026%
~75th_centile	0.0156%	0.0081%	0.0095%	0.0083%	0.0162%	0.0186%	0.0081%
Typical Cold Start Data							
-C&M cost ($/MW cap.)							
Median	147	105	104	79	103	32	75
~25th_centile	87	63	73	46	31	12	54
~75th_centile	286	124	120	101	118	61	89
-EFOR Impact							
Median	0.0106%	0.0088%	0.0088%	0.0055%	0.0035%	0.0088%	0.0060%
~25th_centile	0.0085%	0.0047%	0.0059%	0.0033%	0.0007%	0.0038%	0.0043%
~75th_centile	0.0163%	0.0150%	0.0101%	0.0088%	0.0116%	0.0195%	0.0123%
Startup Time (hours)							
-Typical (Warm Start Offline Hours)	4 to 24	12 to 40	12 to 72	5 to 40 (ST Different)	2 to 3	0 to 1	4 to 48

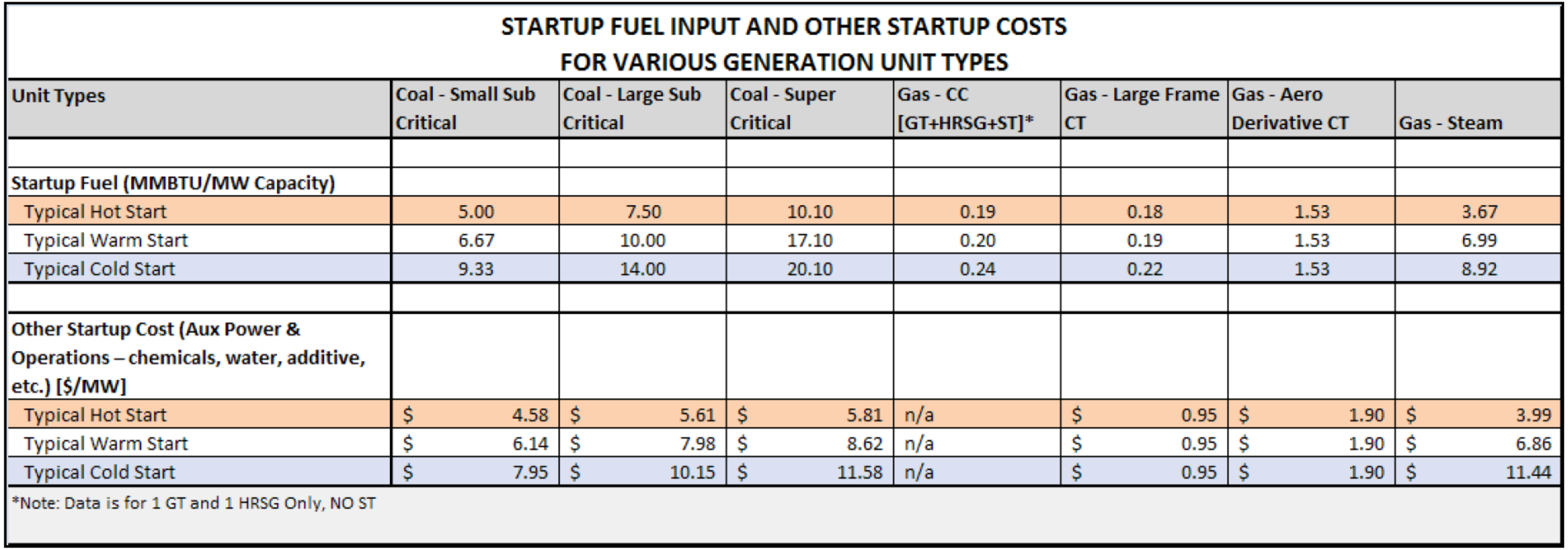
Capital & Maintenance Cost/EFOR Impact (2)

Table 1-1: Continued

Unit Types	Coal - Small Sub Critical	Coal - Large Sub Critical	Coal - Super Critical	Gas - CC [GT+HRSG+ST]	Gas - Large Frame CT	Gas - Aero Derivative CT	Gas - Steam
Typical Load Follows Data							
-C&M cost ($/MW cap.) - Typical Ramp Rate							
Median	3.34	2.45	1.96	0.64	1.59	0.63	1.92
~25th_centile	1.91	1.40	1.52	0.30	0.94	0.42	1.17
~75th_centile	3.84	3.10	2.38	0.74	2.80	1.70	2.32
Range of Load Follow (%GDC)							
-Typical Range (%GDC)	32%	35%	30%	20%	27%	20% (Some 50%)	32%
-Multiplying Factor - Faster Ramp Rate (1.1 to 2x)							
Range*	2 to 8	1.5 to 10	1.5 to 10	1.2 to 4	1.2 to 4	1 to 1.2	1.2 to 6
Note: Multiplying factor - increase in load follow cost (damage) from a faster ramp rate							
Typical Non-cycling Related Costs							
- Baseload Variable Cost ($/MWH)							
Median	2.82	2.68	2.96	1.02	0.57	0.66	0.92
~25th_centile	1.52	1.62	2.48	0.85	0.48	0.27	0.66
~75th_centile	3.24	3.09	3.40	1.17	0.92	0.80	1.42

Startup Fuel and Other Startup Costs

Table 1-3: Startup Fuel Input and Other Startup Costs



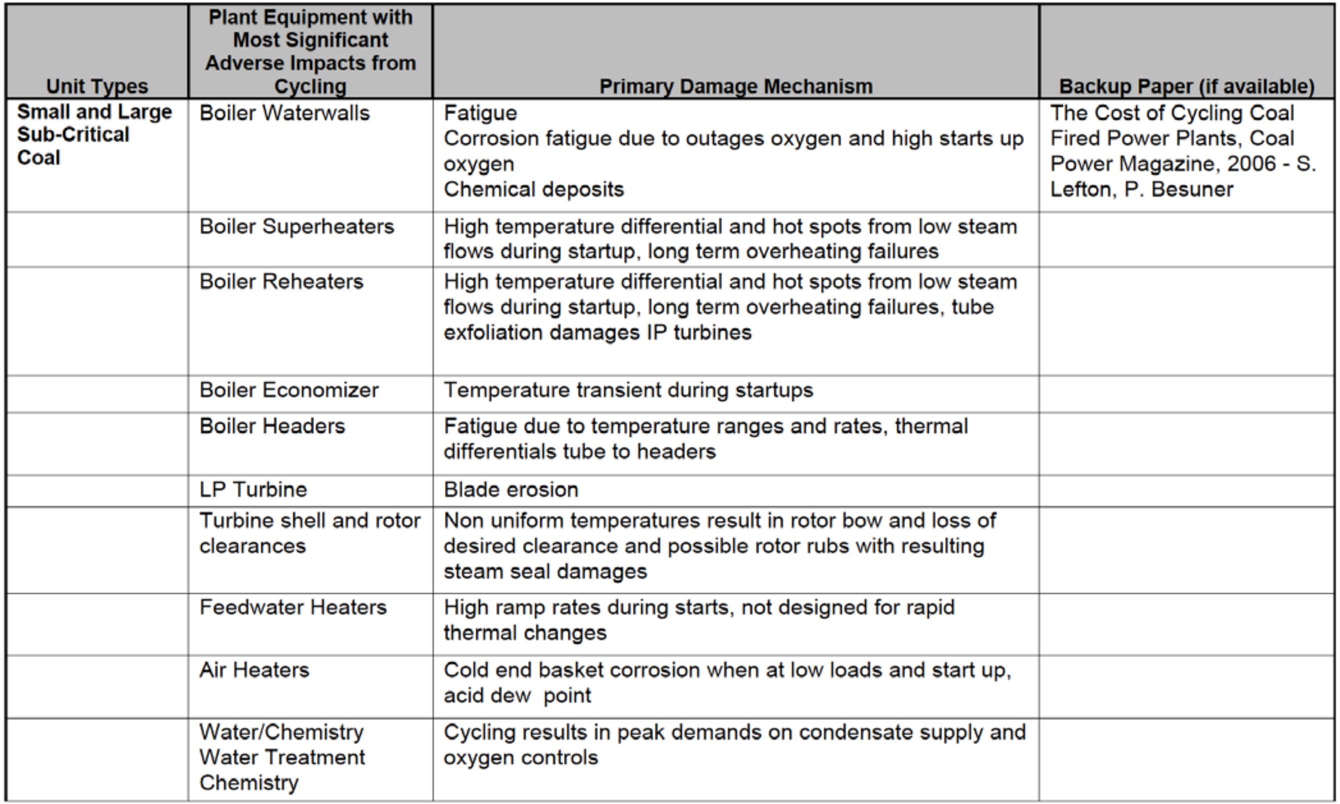
STARTUP FUEL INPUT AND OTHER STARTUP COSTS
FOR VARIOUS GENERATION UNIT TYPES

Unit Types	Coal - Small Sub Critical	Coal - Large Sub Critical	Coal - Super Critical	Gas - CC [GT+HRSG+ST]*	Gas - Large Frame CT	Gas - Aero Derivative CT	Gas - Steam
Startup Fuel (MMBTU/MW Capacity)							
Typical Hot Start	5.00	7.50	10.10	0.19	0.18	1.53	3.67
Typical Warm Start	6.67	10.00	17.10	0.20	0.19	1.53	6.99
Typical Cold Start	9.33	14.00	20.10	0.24	0.22	1.53	8.92
Other Startup Cost (Aux Power & Operations – chemicals, water, additive, etc.) [$/MW]							
Typical Hot Start	$ 4.58	$ 5.61	$ 5.81	n/a	$ 0.95	$ 1.90	$ 3.99
Typical Warm Start	$ 6.14	$ 7.98	$ 8.62	n/a	$ 0.95	$ 1.90	$ 6.86
Typical Cold Start	$ 7.95	$ 10.15	$ 11.58	n/a	$ 0.95	$ 1.90	$ 11.44

*Note: Data is for 1 GT and 1 HRSG Only, NO ST

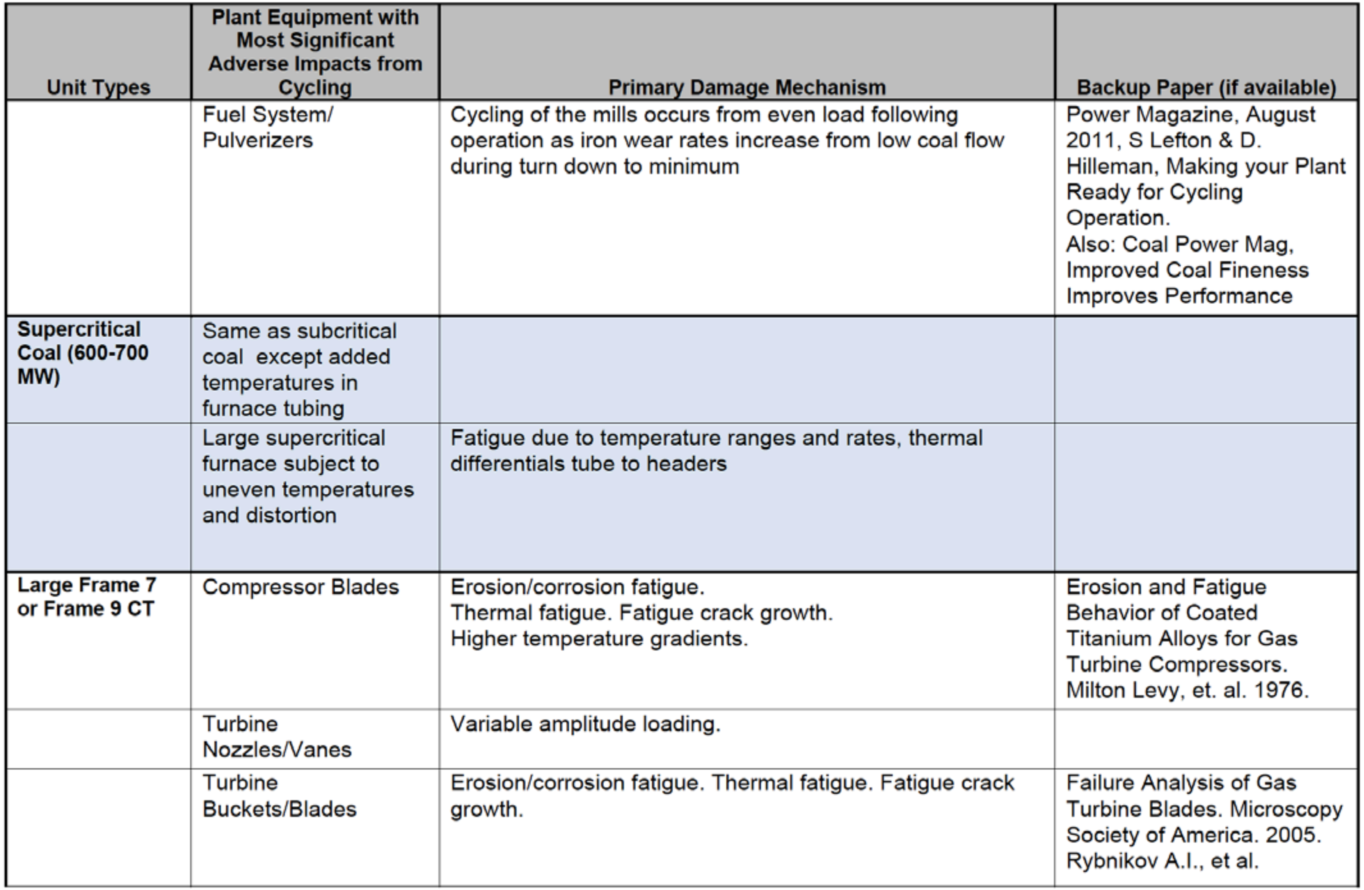
Components Impacted by Cycling

Table 1-5: Specific components typically affected by cycling



Unit Types	Plant Equipment with Most Significant Adverse Impacts from Cycling	Primary Damage Mechanism	Backup Paper (if available)
Small and Large Sub-Critical Coal	Boiler Waterwalls	Fatigue Corrosion fatigue due to outages oxygen and high starts up oxygen Chemical deposits	The Cost of Cycling Coal Fired Power Plants, Coal Power Magazine, 2006 - S. Lefton, P. Besuner
	Boiler Superheaters	High temperature differential and hot spots from low steam flows during startup, long term overheating failures	
	Boiler Reheaters	High temperature differential and hot spots from low steam flows during startup, long term overheating failures, tube exfoliation damages IP turbines	
	Boiler Economizer	Temperature transient during startups	
	Boiler Headers	Fatigue due to temperature ranges and rates, thermal differentials tube to headers	
	LP Turbine	Blade erosion	
	Turbine shell and rotor clearances	Non uniform temperatures result in rotor bow and loss of desired clearance and possible rotor rubs with resulting steam seal damages	
	Feedwater Heaters	High ramp rates during starts, not designed for rapid thermal changes	
	Air Heaters	Cold end basket corrosion when at low loads and start up, acid dew point	
	Water/Chemistry Water Treatment Chemistry	Cycling results in peak demands on condensate supply and oxygen controls	

Components Impacted by Cycling (2)



Unit Types	Plant Equipment with Most Significant Adverse Impacts from Cycling	Primary Damage Mechanism	Backup Paper (if available)
	Fuel System/ Pulverizers	Cycling of the mills occurs from even load following operation as iron wear rates increase from low coal flow during turn down to minimum	Power Magazine, August 2011, S Lefton & D. Hilleman, Making your Plant Ready for Cycling Operation. Also: Coal Power Mag, Improved Coal Fineness Improves Performance
Supercritical Coal (600-700 MW)	Same as subcritical coal except added temperatures in furnace tubing		
	Large supercritical furnace subject to uneven temperatures and distortion	Fatigue due to temperature ranges and rates, thermal differentials tube to headers	
Large Frame 7 or Frame 9 CT	Compressor Blades	Erosion/corrosion fatigue. Thermal fatigue. Fatigue crack growth. Higher temperature gradients.	Erosion and Fatigue Behavior of Coated Titanium Alloys for Gas Turbine Compressors. Milton Levy, et. al. 1976.
	Turbine Nozzles/Vanes	Variable amplitude loading.	
	Turbine Buckets/Blades	Erosion/corrosion fatigue. Thermal fatigue. Fatigue crack growth.	Failure Analysis of Gas Turbine Blades. Microscopy Society of America. 2005. Rybnikov A.I., et al.

RETURN FROM SEGUE, - BACK TO THE EXAMPLE

Results

- Roxboro Unit 2

Nameplate Rating	670 nMW
Previous Minimum Load	150 nMW
Goals For Program	120 nMW
Actual Min Load Attainment	***85 nMW***

Application of Formulas to Roxboro 2

- **2018 Cycling (671 MW Gross)**

Cold starts	**12**	**EFOR .0057% x 12 = 0.0684%**
Warm Starts	**0**	
Hot Starts	**1**	
Load Following	**193**	**No EFOR Impact**

C&M/Cold Starts	**12 x $105 x 671 =**	**$894,600**
Startup Fuel/Cold	**12 x 14 mmBTU/MW x 671 X $3.25**	**$387,700**
Auxiliary Costs/Cold	**12 x $10.15 x 671**	**<u>$86,500</u>**
Total Cycling Cost		**$1,368,800**
Fuel Savings from Min Load Reduction (movement of load to CCNG)		**<u>$470,000</u>**
Total Impact on Fleet		**$1,838,800**

Ties Reasonably well with Corporate Estimate

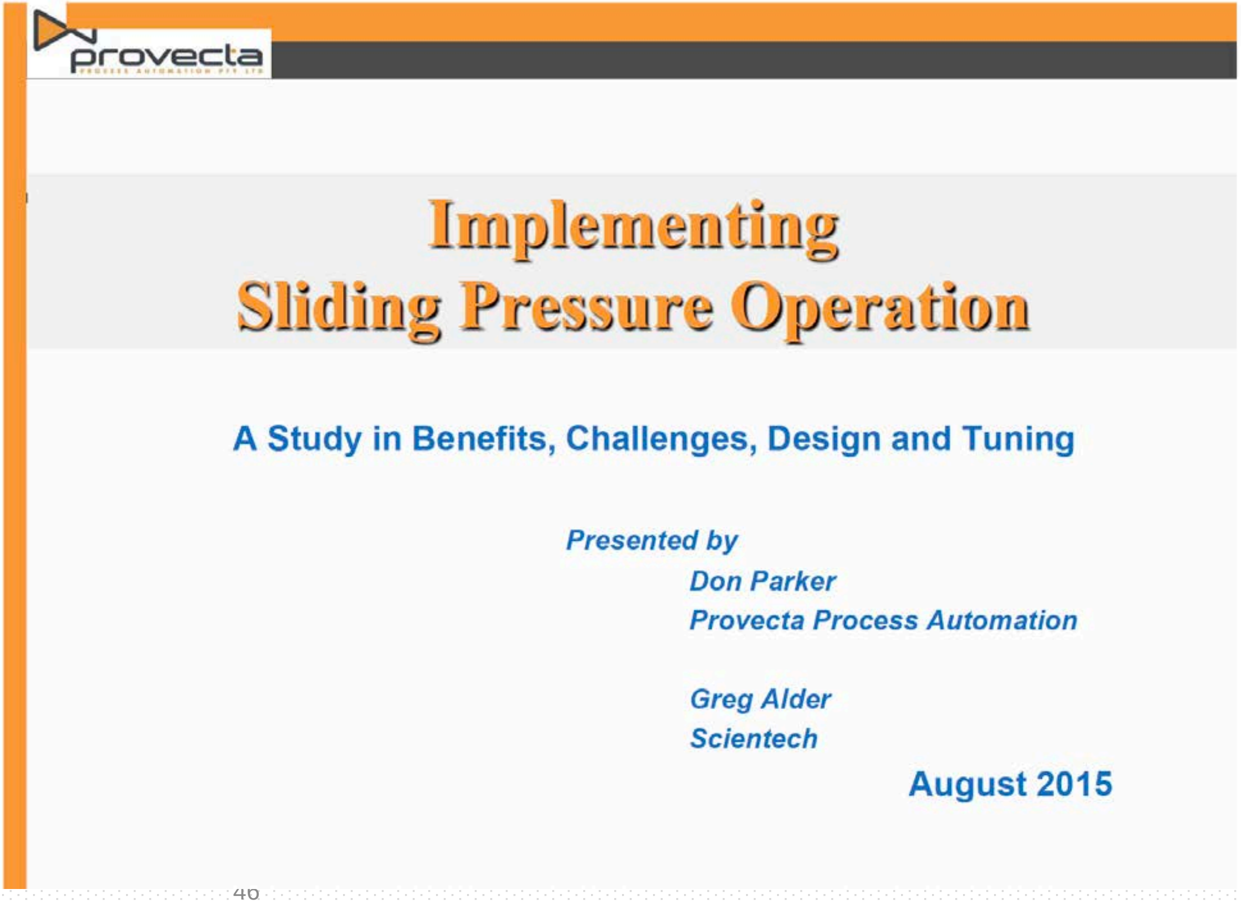
IMPACTS OF REDUCED MINIMUM LOAD

High Level Feedback on Impacts

- Initially experienced water chemistry alarms due to acidity
  - Problem related to Degas scrubbing CO2,
  - Changed the process to use Degas monitor, all Good
- Issues with windbox/burner pressure differential
  - Moving from 3 mills to 2 mills solved this problem
- Exhaust hood sprays were very dependent on condenser backpressure
  - Improving/Maintaining ball cleaning system essential
- ***Main Steam Pressure Issues***
  - ***Moved to Sliding Pressure***
  - ***Big heat rate benefit***

SEGUE #2 – SLIDING PRESSURE

Industry Experience Available



Implementing
Sliding Pressure Operation

A Study in Benefits, Challenges, Design and Tuning

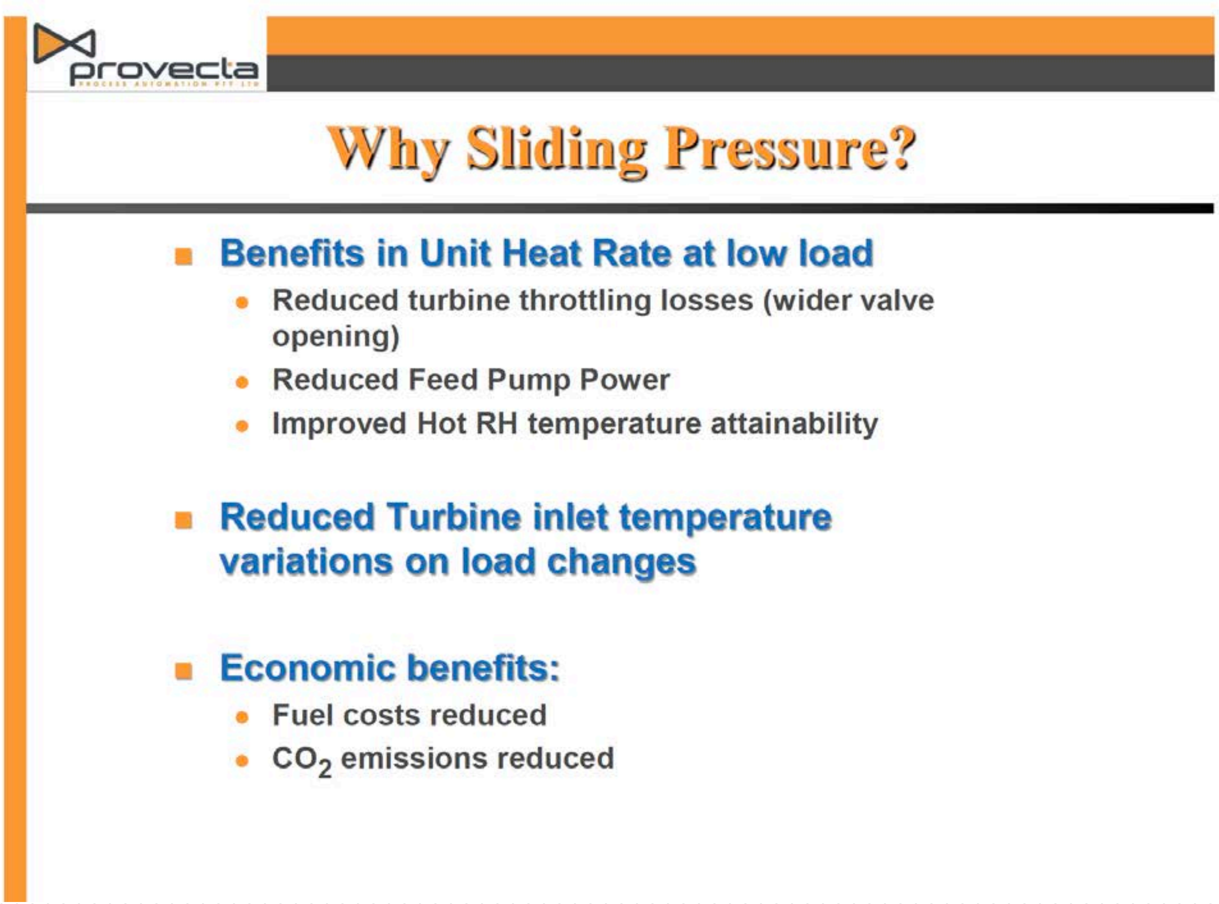
Presented by

Don Parker
Provecta Process Automation

Greg Alder
Scientech

August 2015

Industry Published Benefits of Sliding Pressure



Why Sliding Pressure?

- **Benefits in Unit Heat Rate at low load**
  - Reduced turbine throttling losses (wider valve opening)
  - Reduced Feed Pump Power
  - Improved Hot RH temperature attainability
- **Reduced Turbine inlet temperature variations on load changes**
- **Economic benefits:**
  - Fuel costs reduced
  - CO_2 emissions reduced

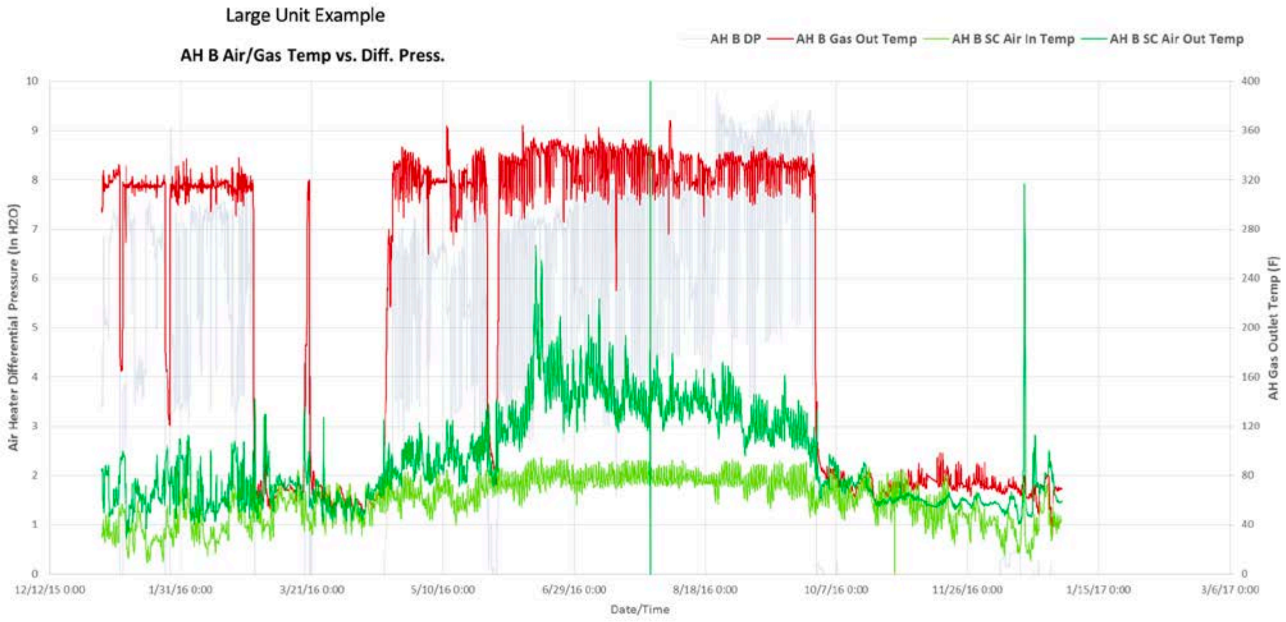
Roxboro 2 Sliding Pressure Impacts

- Unit designed for 2,500 PSI main steam pressure to throttle valve
- Historically runs at a setpoint of 2400 PSI
- At new Minimum load, 2,400 PSI not available so moved setpoint at low load to 2,000 PSI
  - New setpoint allows for reduced throttle valve loss
  - New setpoint drives feedwater pumps at 4000 RPM instead of 4400 RPM, reduced steam demand is available for turbine
- Plant realized over ***500 BTU/kWHr heat rate improvement*** at min load due to reduced steam pressure.
- Plant is exploring a further reduction to 1,800 PSI.

ONE LAST SEGUE BEYOND ROXBORO

AH STEAM COILS/BYPASS DAMPERS

The Value of Steam Coils

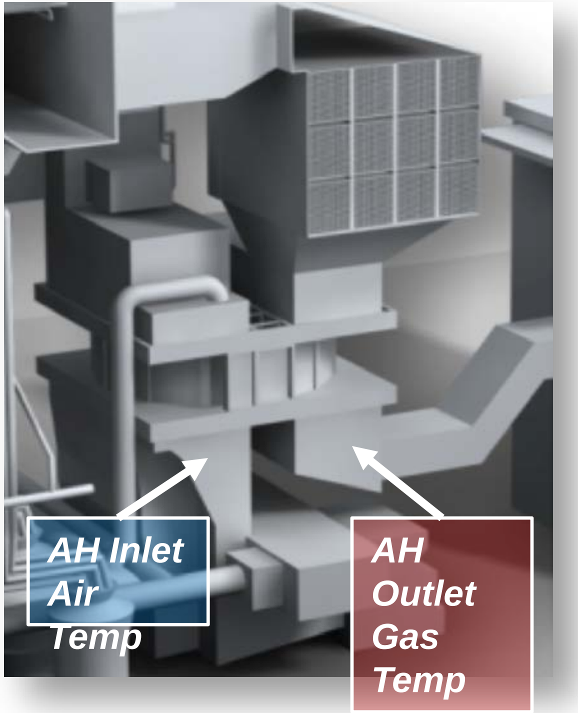


Eliminating Acid Gas condensable material at the Air Heater inlet eliminates the need for Steam Coil or Bypass Damper usage

But what is the "Value" of that action.

In a nutshell it depends on where the steam for the steam coils is extracted.

Air Heater – Steam Coil Impact

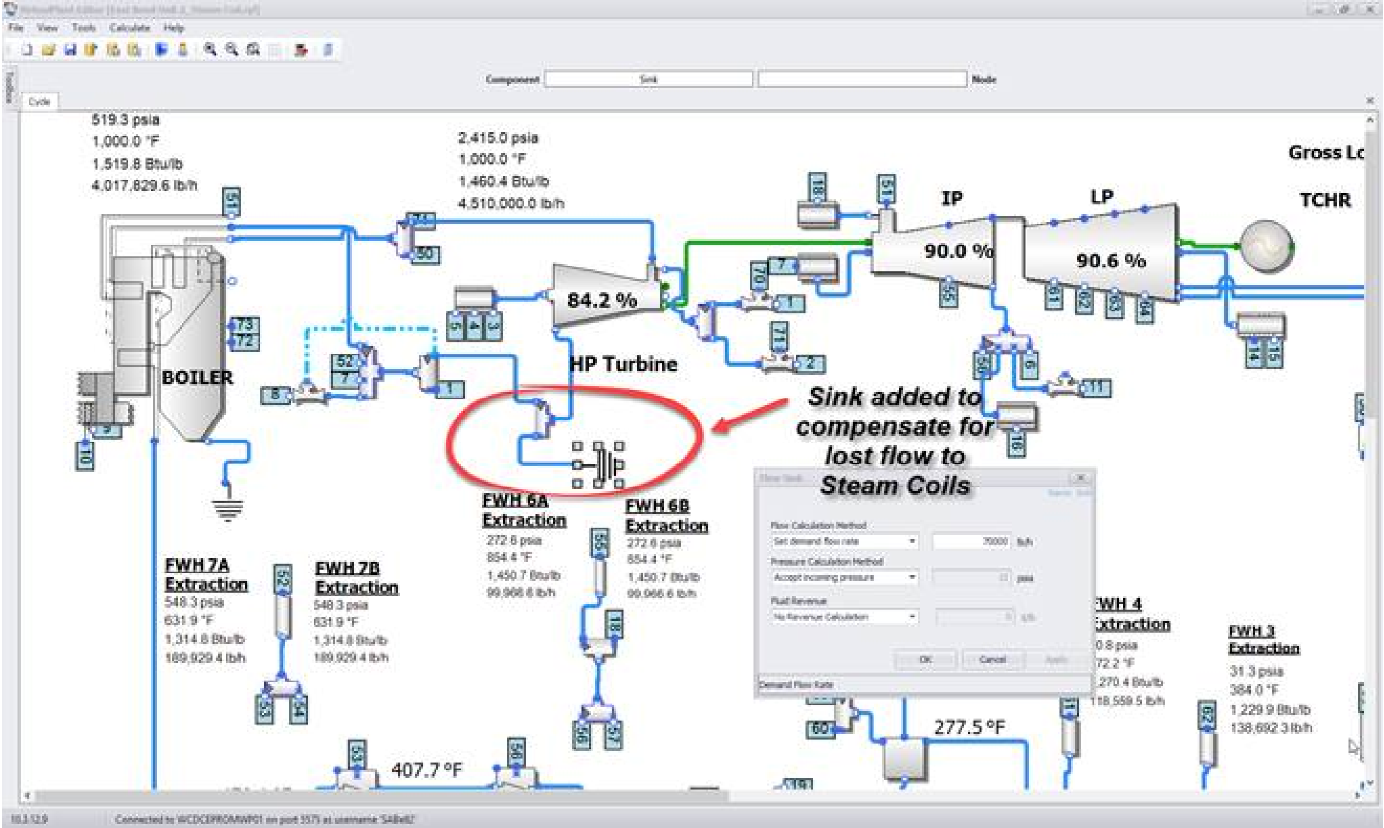


AH Outlet Gas Temp is Key

- Inlet air temp is adjusted via Steam Coils to maintain a desired AH Outlet gas temp
- Outlet gas temp is set to avoid condensable fouling
- It takes 0.24 BTU to raise 1 Lb of Inlet air by 1 degree F

Eliminating condensable material via hydrated lime injection eliminates the need for steam coils

The Importance of Steam Extraction Point



Component: Sink

519.3 psia
1,000.0 °F
1,519.8 Btu/lb
4,017,829.6 lb/h

2,415.0 psia
1,000.0 °F
1,460.4 Btu/lb
4,510,000.0 lb/h

Sink added to compensate for lost flow to Steam Coils

FWH 7A Extraction
548.3 psia
631.9 °F
1,314.8 Btu/lb
189,929.4 lb/h

FWH 7B Extraction
548.3 psia
631.9 °F
1,314.8 Btu/lb
189,929.4 lb/h

FWH 6A Extraction
272.6 psia
854.4 °F
1,450.7 Btu/lb
99,966.6 lb/h

FWH 6B Extraction
272.6 psia
854.4 °F
1,450.7 Btu/lb
99,966.6 lb/h

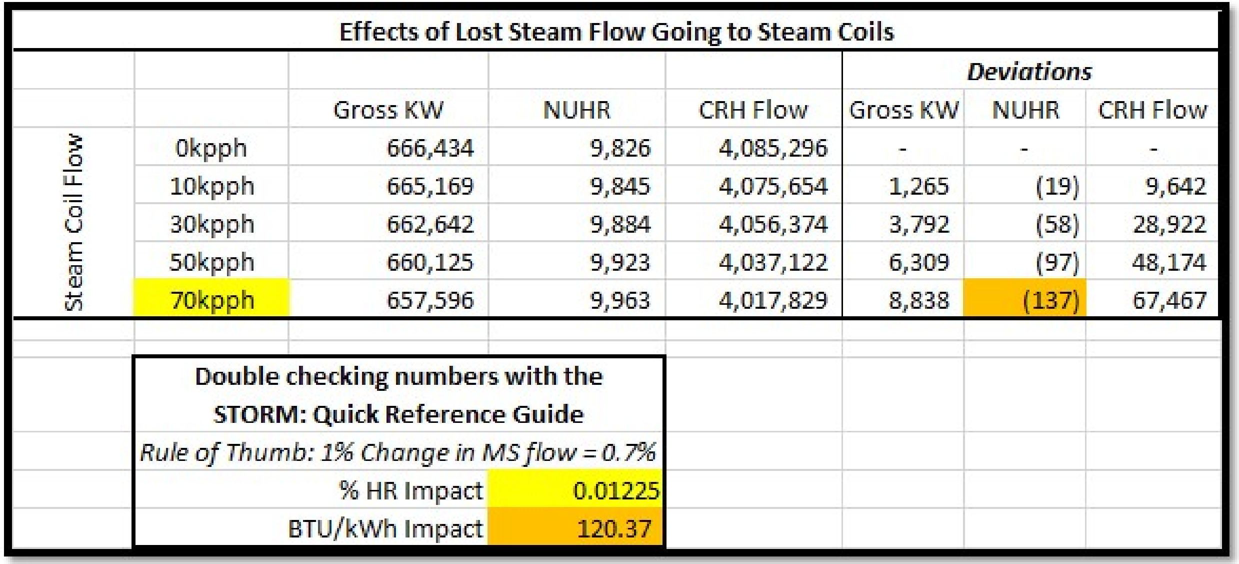
WH 4 xtraction
0.8 psia
72.2 °F
270.4 Btu/lb
118,559.5 lb/h

FWH 3 Extraction
31.3 psia
384.0 °F
1,229.9 Btu/lb
138,692.3 lb/h

Flow Calculation Method: Set demand flow rate — 70000 lb/h
Pressure Calculation Method: Accept incoming pressure — psia
Fluid Revenue: No Revenue Calculation
Demand Flow Rate

How To Identify the Value to You

1. Calculate the Total mmBTU used to power the Steam Coils
2. Using 1400 BTU/Lb of Steam, calculate the approx. kpph of steam extracted
3. Take that number as a ratio of the total Steam flow into the turbine section following the extraction point.
4. The answer is the total MW lost to AH Auxiliary Power



Effects of Lost Steam Flow Going to Steam Coils

					Deviations		
		Gross KW	NUHR	CRH Flow	Gross KW	NUHR	CRH Flow
Steam Coil Flow	0kpph	666,434	9,826	4,085,296	-	-	-
	10kpph	665,169	9,845	4,075,654	1,265	(19)	9,642
	30kpph	662,642	9,884	4,056,374	3,792	(58)	28,922
	50kpph	660,125	9,923	4,037,122	6,309	(97)	48,174
	70kpph	657,596	9,963	4,017,829	8,838	(137)	67,467

Double checking numbers with the STORM: Quick Reference Guide	
Rule of Thumb: 1% Change in MS flow = 0.7%	
% HR Impact	0.01225
BTU/kWh Impact	120.37

Air Heater Temperature Reduction Projects
Recent Experiences

DUKE
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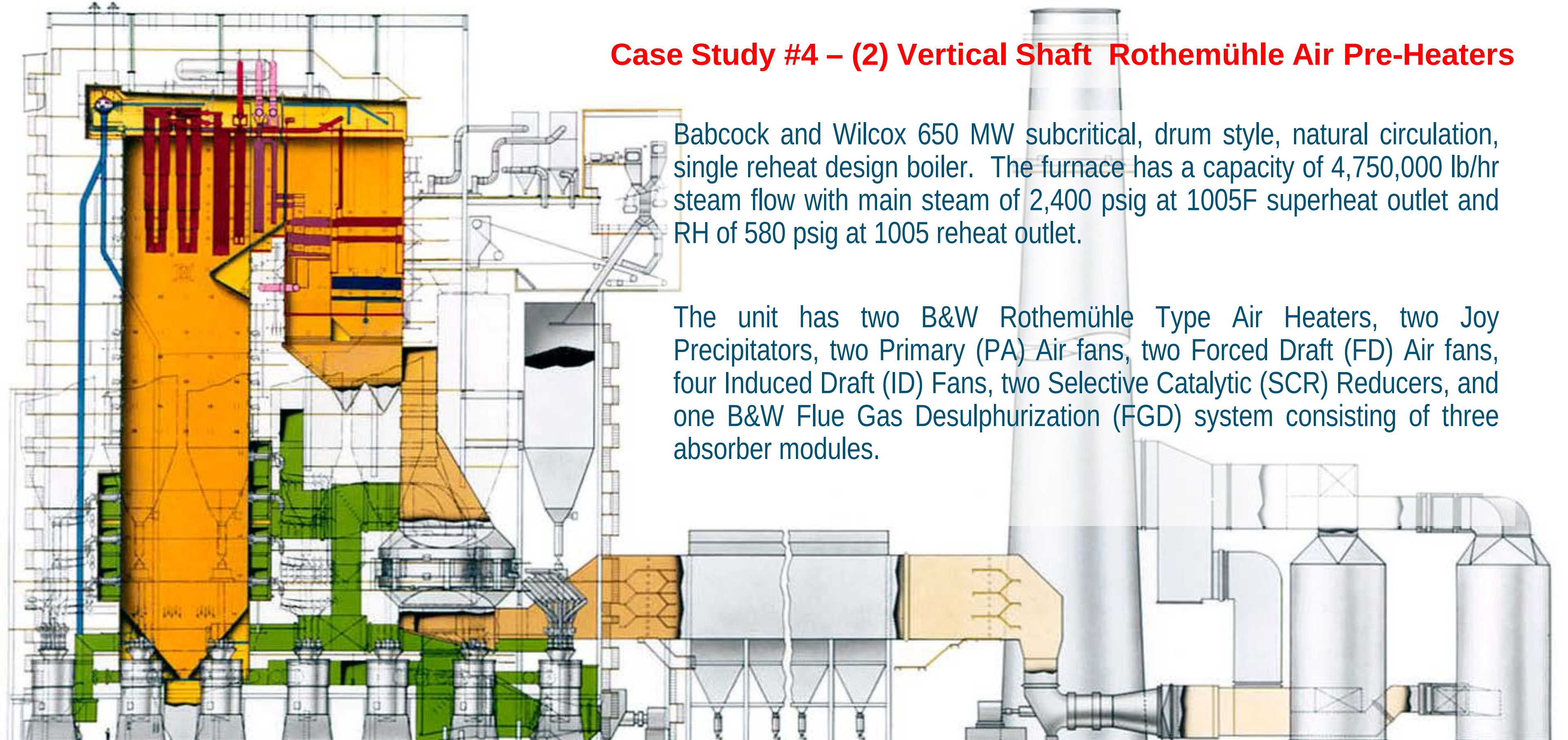
Case Study-4



Case Study #4 – (2) Vertical Shaft Rothemühle Air Pre-Heaters

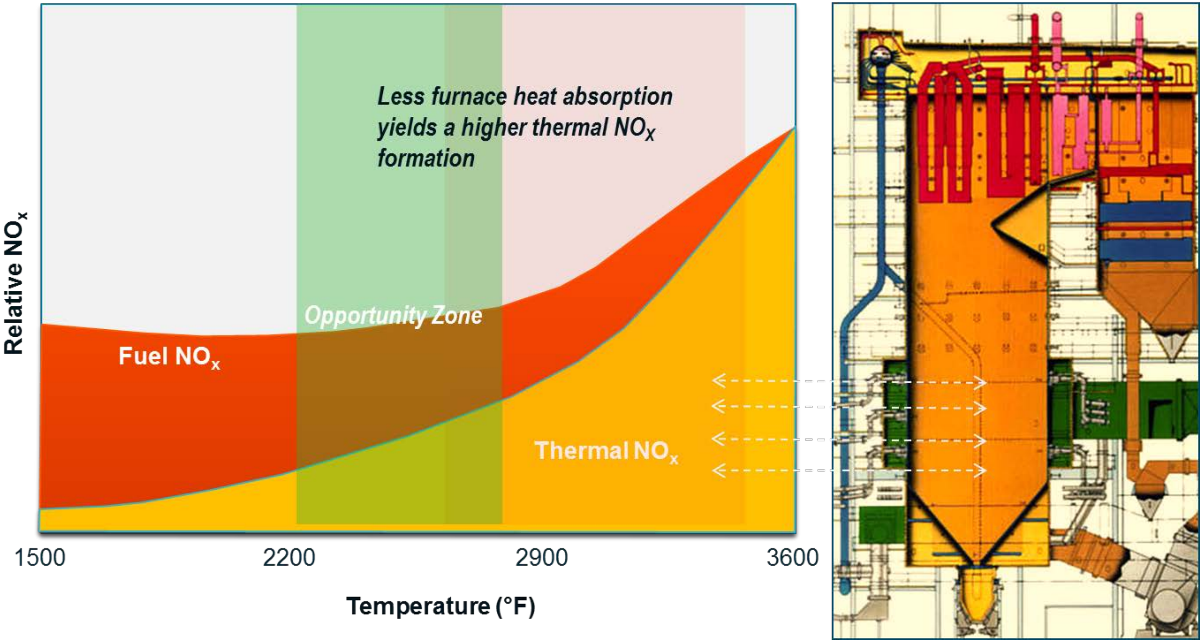
Babcock and Wilcox 650 MW subcritical, drum style, natural circulation, single reheat design boiler. The furnace has a capacity of 4,750,000 lb/hr steam flow with main steam of 2,400 psig at 1005F superheat outlet and RH of 580 psig at 1005 reheat outlet.

The unit has two B&W Rothemühle Type Air Heaters, two Joy Precipitators, two Primary (PA) Air fans, two Forced Draft (FD) Air fans, four Induced Draft (ID) Fans, two Selective Catalytic (SCR) Reducers, and one B&W Flue Gas Desulphurization (FGD) system consisting of three absorber modules.

Case Study-4

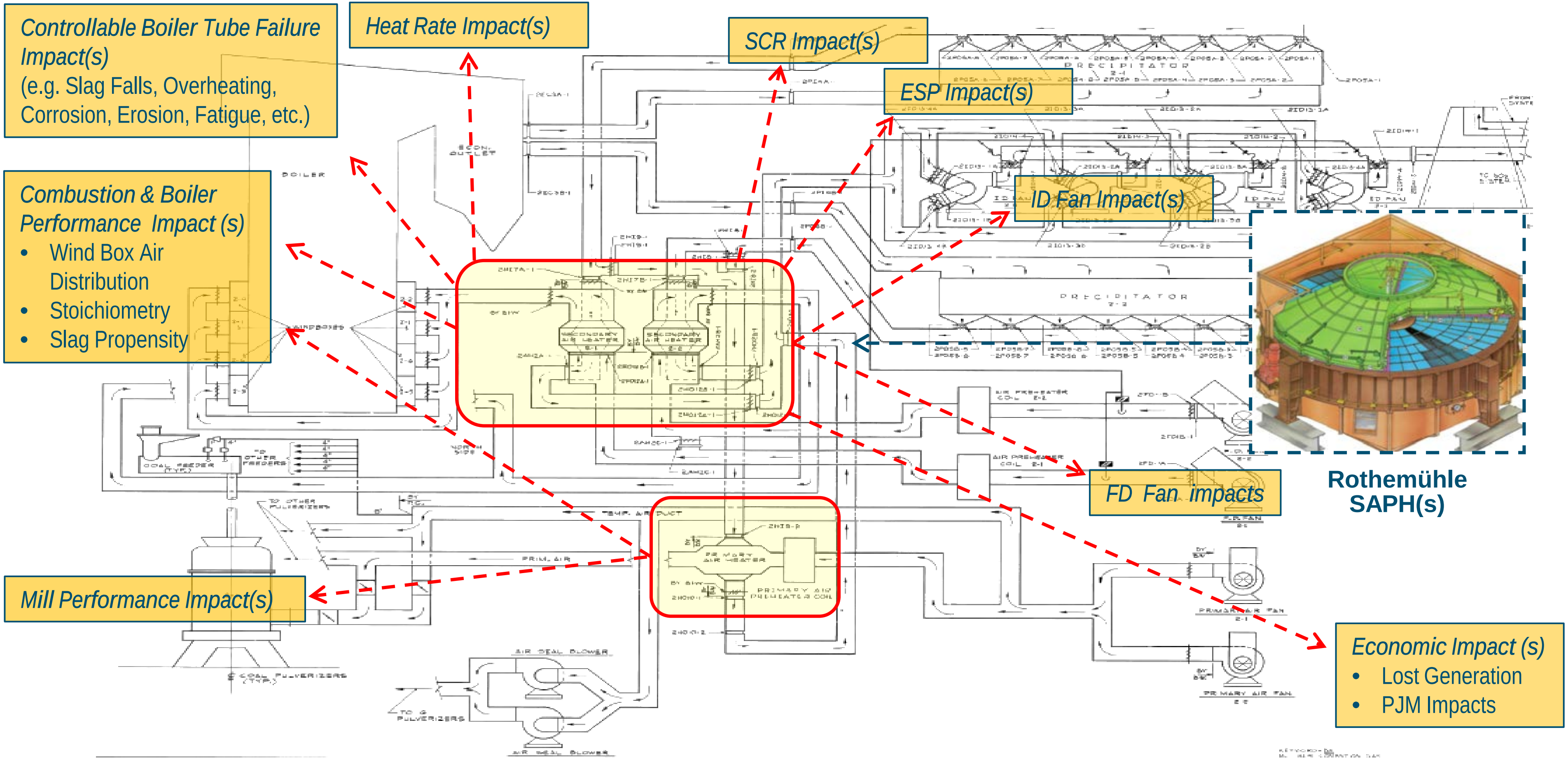
Challenges:

- FD and ID fan limitations (due to air heater leakage & Cold End Average Temperature / Steam Coils)
- Non-optimal W-Box to furnace DPs
- O_2 variations
- Increased furnace slagging with reduced combustion intensity in the lower furnace
- Problematic burner eyebrows (due to sub-stoichiometric zones)
- Poor airflow distribution in to the compartmentalized wind boxes (due to lower plenum pressures from the reduced secondary airflow)
- Excess air limitations (due to SAPH leakage limiting the O_2 set-point)
- Air-Fuel balancing through mill, conduit and burner optimization
- Upper furnace slagging
- RH Spray Flow rates



Less furnace heat absorption yields a higher thermal NO_X formation

Case Study-4: Air Heater Degradation Impacts Reliability



Controllable Boiler Tube Failure Impact(s)
(e.g. Slag Falls, Overheating, Corrosion, Erosion, Fatigue, etc.)

Heat Rate Impact(s)

SCR Impact(s)

ESP Impact(s)

ID Fan Impact(s)

Combustion & Boiler Performance Impact (s)
- Wind Box Air Distribution
- Stoichiometry
- Slag Propensity

FD Fan impacts

Rothemühle SAPH(s)

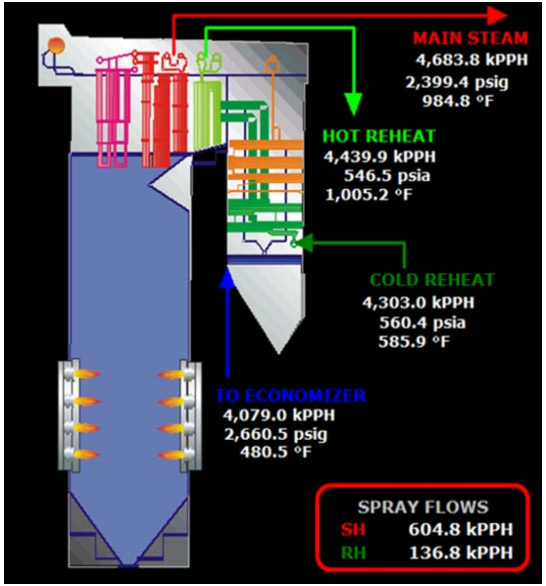
Mill Performance Impact(s)

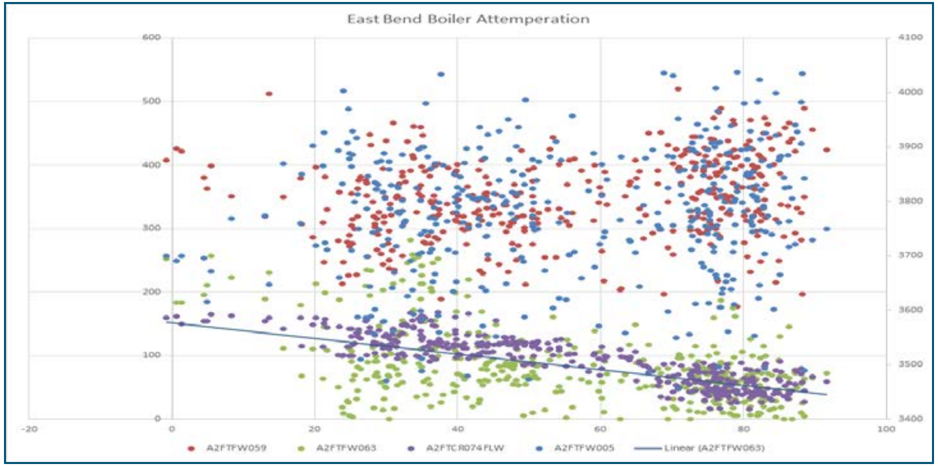
Economic Impact (s)
- Lost Generation
- PJM Impacts

Cast Study-4: Boiler Cleaning System Constraints

RH atemperation correlates with the Secondary Air Preheat Coil Flow. The magnitude of the increase in SAH Preheat Coil flow is around 100KPPH which also lines up well.

The bulk of the trend you are seeing is seasonal due to colder temperatures requiring more secondary air preheating which does rob the Cold Reheat of thermal mass requiring increases spray flow rates.

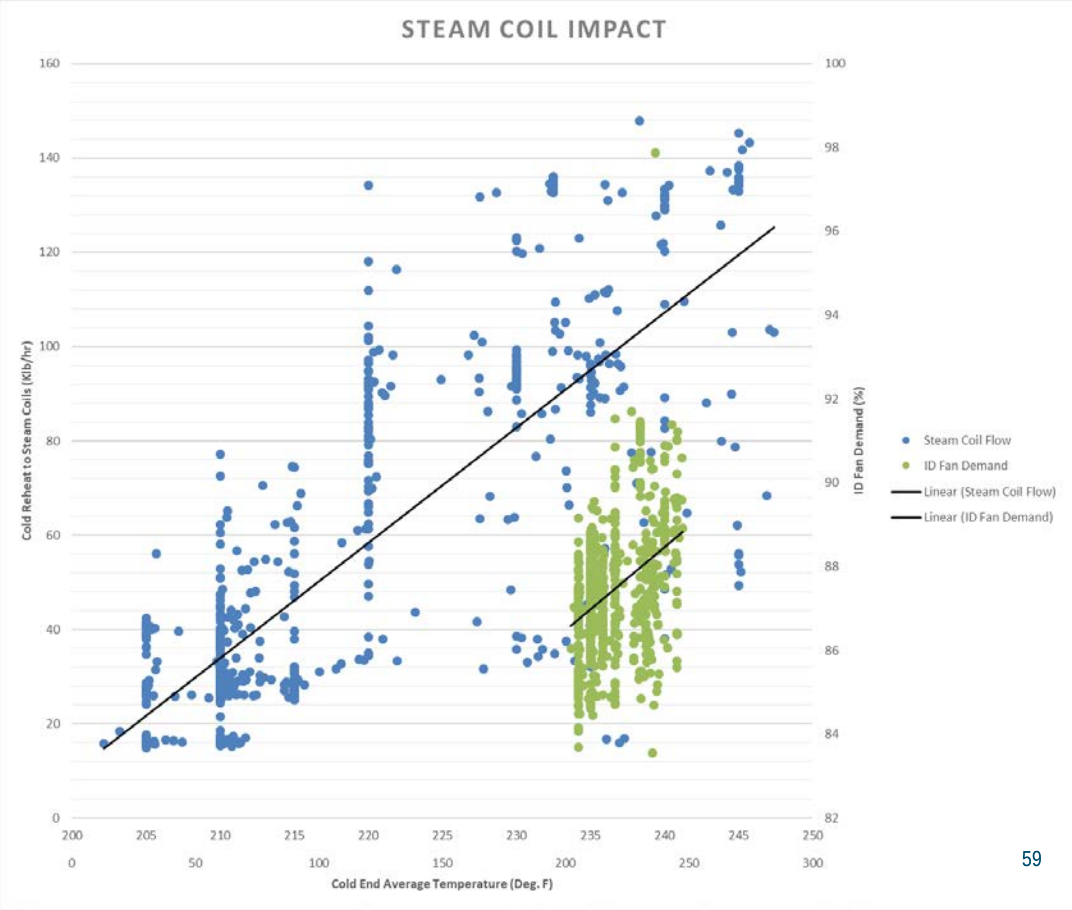




Cost of RH Attemperation	Ambient Temp > 50°F	Ambient Temp < 50°F
RH Spray	~70kpph	~200kpph
Heat Rate Increase(Btu/kWh)	---	+250 Btu/kWh (+2.3%)

Cast Study-4: Steam Coils

- Steam coils at East Bend are fed from Cold Reheat
- Station typically operates in the 230-240 deg. F cold end average temperature range
- Hydrated lime injection trial prior to the air heater in August ‘16 showed reliable operation down to 205 deg. F ACET
- Air heater DP’s dropped during this time and the unit was currently operating fan limited prior to the testing which cleared up with the reduced ACET
- Permanent Hydrated lime system was delayed due to investigation of PM carryover issues, currently scheduled to be in service 11/19
- Further optimization of the ACET will take place after complete implementation



SUMMARY & CONCLUSION

Summary

In the presence of current science on hydrated lime injection, distribution and performance:

1. ***SCR Minimum Operating Temperature can be eliminated as a plant operating constraint,***
2. ***Air Heater outlet gas temperatures can follow the natural gas temperature patterns without the need for auxiliary heating***
3. ***Based on the elimination of acid gas induced constraints on plant operation,***
    1. ***Minimum Unit loads can approach 25% of MCR***
    2. ***Outlet gas temperatures can drop into the mid – low 200s.***

But you MUST be Willing to Take the Leap!

Slow Decline to Closure

More Operating Hours & Improved Value

Questions?

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