FINAL TECHNICAL REPORT

"Carbon Management for Existing Power Plants via Measurement and Control Optimization"

National Energy Technology Laboratory

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Principal Authors / Contributors:

(1) Mr. Eric Huelson, Mr. Newton Logan, Dr. Andrew D. Sappey
(2) Mr. Greg Tanck
(3) Mr. Chris Steiger, Mr. Nate Jakinovich
(4) Mr. JP Scott, Mr. Todd Alleshouse
(5) Mr. Peter Spinney
(6) Mr. Jeff Grott, Mr. Harry Winn

(1) Zolo Technologies, Inc., Boulder, Colorado USA
Corresponding author: Eric C. Huelson
4946 N. 63rd Street Boulder, Colorado 80301
(303) 604-5816
ehuelson@zolotech.com

(2) Black and Veatch, Overland Park, Kansas USA
(3) DTE Energy Co., Belle River Unit2, China, Michigan USA
(4) American Electric Power, John Amos Unit3, Winfield, West Virginia USA
(5) NeuCo, Inc., Boston, MA, USA
(6) Emerson Process Management, Pittsburgh, PA, USA

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Abstract

The National Energy Technology Laboratory (NETL), part of the US Department of Energy (DOE) has sponsored two technology demonstration projects at coal-fired power plants to reduce CO_2 through combustion balancing and optimization. The Zolo Technologies-led projects at DTE Belle River Unit 2 and AEP John Amos Unit 3 demonstrated significant reduction of CO_2/MWh via generation efficiency improvements enabled by new laser-based sensor technology in conjunction with combustion optimization software. The primary project tools are tunable diode laser absorption spectroscopy (TDLAS)-based in-furnace measurement of CO, H_2O, O_2 and temperature, combustion optimization software, and plant personnel training focused on generation efficiency. Performance testing at the DTE plant from July 25 to July 30, 2010 shows benefits from the integration of these tools on the order of 2.3% reduction in CO_2/MWh intensity. Similar improvements were obtained on the AEP boiler with manual tuning alone. In both cases, the plants also received improvements in heat rate and reductions in NOx levels. These benefits were obtained with minimal changes in boiler CO emissions and unburned carbon content and without other boiler performance degradation.

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Executive Summary

The National Energy Technology Laboratory (NETL) sponsored a Zolo Technologies led project at AEP Amos Unit 3 (AEP) and DTE Belle River Unit 2 (DTE) to demonstrate the reduction of CO_2/MWh via generation efficiency improvements.

The objective of the project is to reduce CO_2/MWh by 2.0% through combustion balancing and boiler optimization. The key project tools are plant personnel training, an in-furnace combustion monitoring system, expert engineering services, and software optimization. The technologies and methods developed during this project can be used to provide significant, rapid, and low-cost reductions in CO_2 emissions on the majority of coal-fired boilers across the US.

The DTE project trained plant personnel on generation efficiency best practices, installed an in-furnace measurement sensor, conducted manual combustion balancing, and integrated in-furnace data into combustion optimization software. At AEP similar steps have been taken but the optimizer has not yet been fully integrated.

Results from the demonstration are encouraging as both plants demonstrated improved combustion conditions and CO_2/MWh reductions of 1.80% for manual tuning at AEP and 2.34% with optimizer control at DTE. CO_2/MWh measurements were corroborated with heat rate measurements that showed the same performance trends.

		AEP Manual Tuning Results			DTE Optimizer Tuning Results		
	Units	CO2 CEMS Method	Controllable Losses	Heat-Loss Method	CO2 CEMS Method	Controllable Losses	Heat-Loss Method
Efficency	%	1.80%	0.88%	0.56%	2.34%	1.55%	1.71%
Change in Heat Rate	Btu / kWh	181	88	56	243	161	177
Fuel Savings	tons / yr	73,000	36,000	23,000	60,750	40,241	44,395

These performance improvements were achieved with negligible changes in the plant's emissions of CO or SOx, a reduction of NOx emissions between 5% to 20% and no measured changes in LOI (Loss-On-Ignition, which means unburned fuel).

The two initial demonstration projects indicate that the combination of in-furnace sensing technology integrated with software optimization has the potential to significantly reduce CO_2 emissions. However, these two projects have also shown that there are issues to be resolved before the integration of new hardware, software, manual tuning, plant training, validation etc., can be considered proven.

1. The differences in boiler types, fuels, plant procedures and cultures, between the two demonstration sites led to dissimilar implementation strategies, task durations and benefits. The next steps in the demonstration should be to validate the project approach on a wider selection of boiler types, fuels, dispatch profiles, and utilities.

2. There are unresolved discrepancies between the different methods used to measure efficiency improvements.

3. While it appears that the results are sustainable, the project time period was too short to validate that the efficiency improvements will be sustained over periods of a year or more.

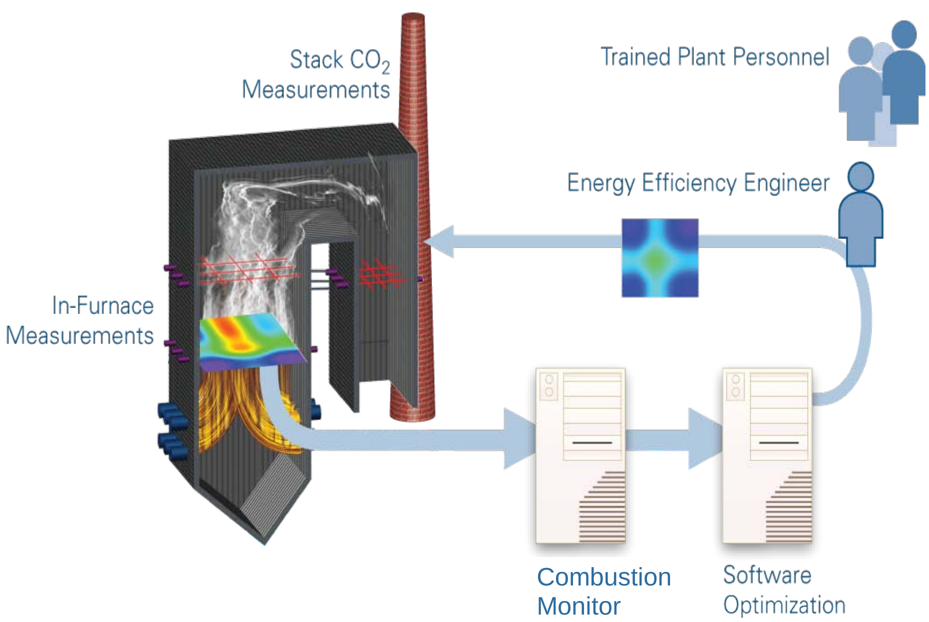
Background Data

Coal-fired power plants provide approximately 49% of the electricity generated in the United States.[1] However, these plants produce 82% of the total CO_2 associated with power generation activities.[1] This fact represents both an opportunity and a challenge. Unfortunately, many generation efficiency improvement projects are capital intensive or are not incentivized by government regulations.[2,3] In general, plants optimize their operations considering: 1) they must "keep the lights on" and 2) they must abide by government regulations concerning the emission of NO_x, SO_x, and CO. As a result, the primary focus of plant operations is availability.

Climate change, the desire for energy independence, and resource conservation are beginning to change attitudes towards the importance of generation efficiency. In February 2010, the NETL held an industry workshop – "Improving the Thermal Efficiency of Existing Coal-Fired Power Plants in the United States".[3] Over 50 leading industry experts, utility owners and operators, equipment vendors, energy consultants, power industry associations, and research organizations to explore this topic. The workshop resulted in a number of opportunities to improve the thermal efficiency of these plants as shown below:

Key Technical Opportunities to Increase Thermal Efficiency	
• *Train Workers on Efficiency Best Practices*	• Replace seals: airheaters, condensers, boilers
• *Dedicated Performance Engineer*	• Upgrade turbines: dense-pack, seals
• *Optimize processes with advanced tools and instrumentation*	• Variable speed motors
• *Real-time performance monitoring*	• Lower stack temperatures
• *Standardize performance metrics*	• Coal drying
• *Reduce excess: air, water, steam and flue gas leakage*	• Flue gas heat exchangers
	• Intelligent Sootblowing

This project aims to provide low cost, immediate generation efficiency improvements that also reduce CO_2 while not compromising unit availability. The project's focus is to integrate many of the opportunities identified in the NETL workshop (those italicized in the table above) to demonstrate the potential thermal efficiency improvement opportunity on two typical coal-fired plants as shown in the graphic below.



A 1.80% and 2.34% efficiency increase has now been demonstrated at AEP and DTE respectively. If an improvement of this magnitude (~2%) is extrapolated across the United States coal-fired boiler fleet, it would be equivalent to doubling immediately the total amount of CO_2-free electricity generated by wind and solar photovoltaic (PV) energy in the United States but at roughly 1/100th the cost of solar PV and 1/25th the cost of wind power.[2]

Theoretical

Figure 1 depicts tradeoffs that must be addressed in boiler operation. Very generally, the air/fuel ratio must be adjusted carefully to optimize combustion efficiency. Too much excess air decreases overall efficiency because it has the unwanted effect of cooling the combustion gasses, and the fans that blow the excess air into the boiler represent a parasitic system loss (They require more electricity to blow more air). In addition, too much excess air creates additional NO_x. On the other hand, excess air has benefits. If staged and directed properly, it assures low CO emissions and low carbon content in the fly ash. It can provide a slightly oxidizing environment near the boiler walls that helps to prevent wall wastage and down time from boiler tube leaks. Excess air also tends to aid in the control of slagging which can cause significant boiler radiative and convective losses if left unchecked and can cause unplanned boiler outages due to slag fall and fouling.

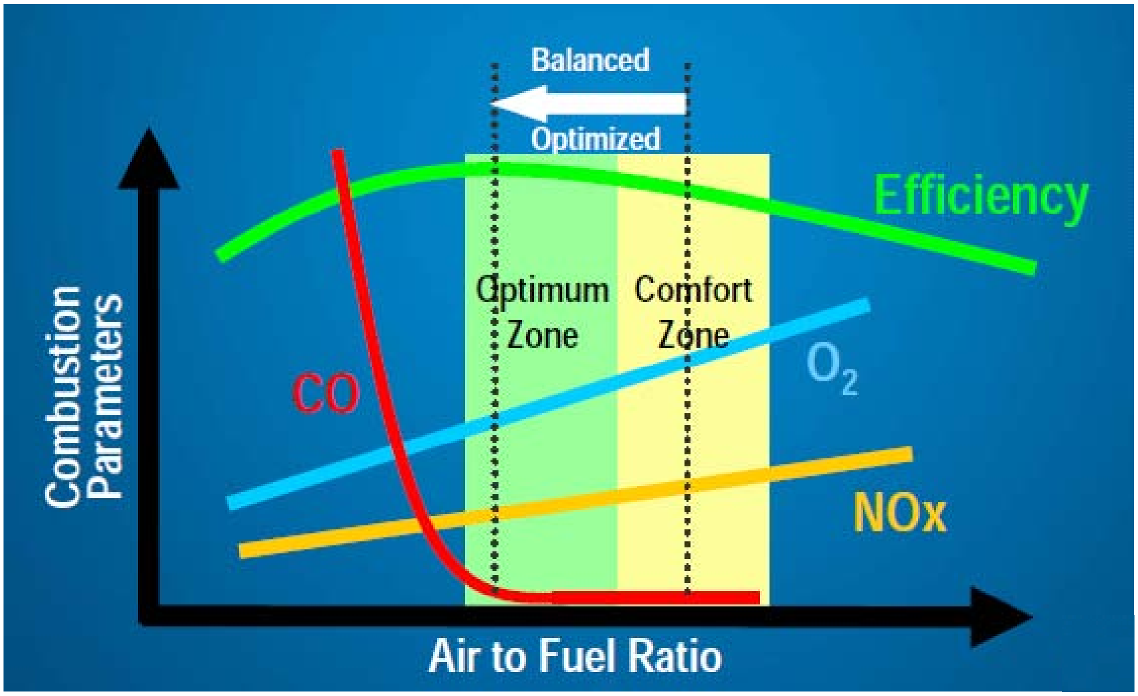


Figure 1: Operation tradeoffs of air to fuel ratios variation

In general, boilers operate with more excess air than is necessary for optimal combustion. One reason for operating with more than optimal excess air is limited visibility of the combustion process. Without an in-furnace combustion monitor, real time visibility into the balance of combustion process is limited to traditional economizer oxygen probes. These probes offer only a point source measurement, are downstream of the combustion process, and are independently calibrated leading to natural variations between points.

Plants that are concerned about boiler performance have recognised this uncertainty and will typically tune their boiler 1-2 times/year using a professional tuning engineer and multi-depth extractive gas samples to check for gas uniformity. Unfortunately, natural variations in combustion performance will reduce the combustion balance after tuning is complete. Even if the total level of O_2 is maintained at a reasonable level, a combustion imbalance can lead to both reducing and excess O_2 sections that may not be observed by the oxygen probes. In this situation a plant would see both high NO_x in the O_2 rich regions and high CO and potential slag formation in the regions where O_2 is depleted. Without visibility of combustion conditions, availability requirements require increasing excess O_2 to minimize the O_2 depleted regions. An example of imbalances that can exist is demonstrated in Figure 2 by Zolo*BOSS* tomographic images observed early in the integration of the system at Belle River.

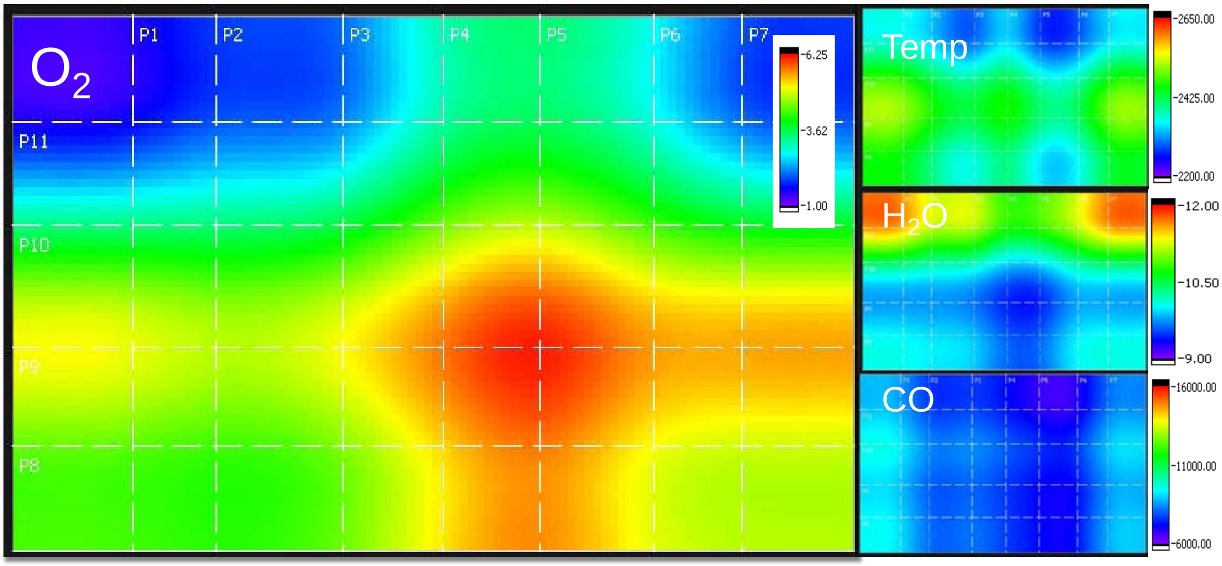


Figure 2: Belle River boiler distributions from testing on 4/22

This project aimed to balance combustion so that localized areas of high O_2 could be minimized and overall excess air could be safely reduced to realize efficiency gains. Combustion balancing was made possible by the laser-based in-furnace combustion monitor, a software optimizer to maintain the balance, and oversight from plant engineers and operators.

Project Details

The objective of this project is to reduce CO_2/MWh and increase efficiency through combustion balancing and sustainable excess air reduction. The steps needed to transform the theory of efficiency improvement to practice are critical both for generating results and producing a repeatable process. This section will describe the "blueprint" of the demonstrations so that its main concepts and techniques can be adopted into other units.

Project Tasks

- Select Power Plants
- Establish Project Components
    - In-furnace Combustion Monitor
    - Software Optimizer
    - Plant Training
    - Plant Remediation
    - Project Management
- Develop Performance Test
- Manual Tuning
- Optimizer Tuning
- Sustaining Results

Power Plants

Two power plants were selected for this initial demonstration: AEP John Amos Station Unit 3 and DTE Belle River Station Unit 2. Components are as follows:

Table 1: Power plant components

Burners	96 burners : DB Riley #5M Controlled Combustion Venturi (CCV), Model 90	40 burners : Babcock Borsig BBP #6N Controlled Combustion Venturi (CCV) dual air zone burners
SOFA	None	21 ports
Turbine Cycle	Single reheat steam turbine with two shafts and two generators with a four-flow LP turbine	Single reheat, tandem compound, four-flow turbine
Feedwater Cycle	Eight-heater feedwater cycle	Seven-heater feedwater cycle
Feedwater Pumps	One steam driven feedwater pump	Two steam driven feedwater pumps
Condenser Cycle	Twin single pass surface condensers with four water boxes fed a parabolic cooling tower	Twin single pass surface condensers with four water boxes fed by river water
Precipitator	One dry electrostatic precipitator	One Dry Electrostatic Precipitator
SCR	One Selective Catalytic Reduction System (SCR)	
Flue Gas	One flue gas desulphurization system	

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Project Components

Equipment, training, and plant involvement are needed to successfully increase efficiency and reduce emissions using the method proposed. The required project components are:

- In-furnace Combustion Monitor : Provide visibility into the combustion process
- Software Optimizer : Maintain balanced combustion given fluctuating boiler inputs

- Plant Training : Integrate the tools and promote efficiency best practices
- Plant Remediation : Address unit control or monitoring uncertainties
- Project Management : Maintain focus on the efforts

In-furnace Combustion Monitor

The Zolo*BOSS* combustion monitor is provided by Zolo Technologies and consists of a laser-based combustion sensor designed for the ultra-harsh combustion environment of a coal powered furnace. The Zolo*BOSS* uses tunable diode laser absorption spectroscopy (TDLAS) measurements, laser multiplexing capabilities, and tomographic algorithms to generate two-dimensional maps of boiler conditions including temperature, O_2, CO and H_2O concentrations. Measurements are obtained directly in the furnace and in real time. This visibility into the combustion zone makes real time combustion balancing possible.

For more information on the ZoloBOSS system see *www.zolotech.com*.

AEP Layout:

The Zolo*BOSS* at John Amos Unit 3 includes fourteen parallel laser paths in the combustion zone of the boiler. Front to rear paths are located above each of the 12 burner columns to enable left to right combustion balancing.

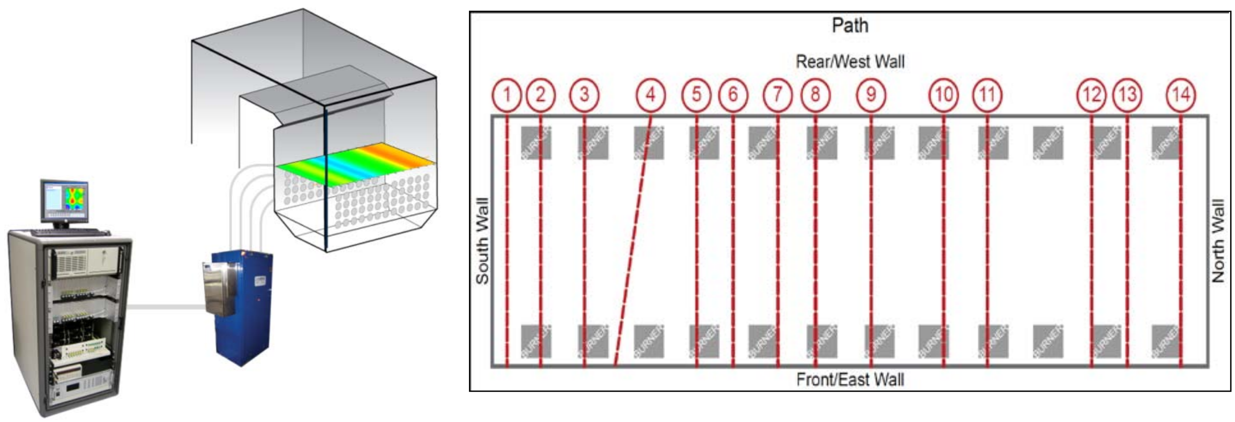

Figure 3: AEP Zolo*BOSS* system and layout

DTE Layout:

The Zolo*BOSS* at Belle River Unit 2 includes a 7x4 grid of laser paths in the combustion zone and three additional laser paths in the superheater pendants. Front to rear paths are located above each burner column and are supplemented by four left to right paths to enable 2D combustion balancing. The three superheater laser paths provide an early warning of fouling conditions based on temperature level and gradient.

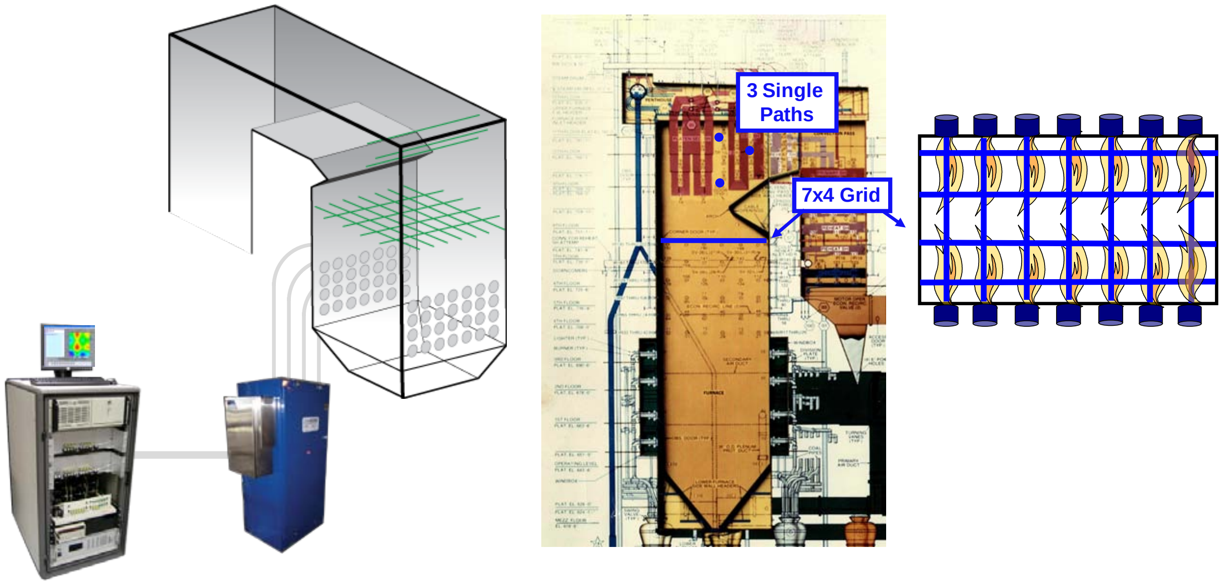

Figure 4: DTE Zolo*BOSS* system and layout

Software Optimizer

The software optimizer biases fuel and air controls to balance combustion and improve efficiency. The introduction of an optimizer with an in-furnace combustion monitor has several advantages:

1. Fuel and air flows are optimized 24/7.
2. The optimizer continually learns and adapts to changing furnace inputs.
3. Real time in-furnace measurements allow for highly correlated optimization control models.

AEP Emerson Optimizer:

The Emerson SmartProcess system uses advanced analytics and artificial intelligence algorithms to achieve combustion balance and minimize emissions. The Emerson is currently being integrated into Unit 3.

For more information on the Emerson SmartProcess optimizer see: http://www2.emersonprocess.com/en-us/brands/smartprocess/Pages/index.aspx.

DTE NeuCo Optimizer:

The NeuCo CombustionOpt system optimizes fuel and air mixing to improve efficiency and reduce emissions. Efficiency improvements are sustained by continuously evaluating control variables and manipulating boiler setpoints. Optimization is provided by neural network and model predictive control technologies that produce real-time closed-loop combustion optimization.

For more information on the NeuCo CombustionOpt optimizer see *www.neuco.net*.

Plant Training

Efficiency training was delivered by Black and Veatch, Zolo Technologies and the plant champion. Training consisted of:

- CO_2/MWh reduction and boiler efficiency awareness
- Zolo*BOSS* operation and maintenance
- Combustion optimization software operation and support

- Live balancing exercise using Zolo*BOSS* tomography

Plant Remediation

Plant remediation consists of improving both the combustion controls and the sensors used to monitor the emissions and power. It was observed that two phases of remediation work are possible.

- Phase I: Initial boiler control or measurement issues are addressed.
  - Remediation includes items such as integration of a CO_2 monitor, adding sensors, or calibrating instrumentation.
- Phase II: Control issues addressed after introduction of the combustion monitor and optimizer.
  - Insitu combustion monitor data, combined with project efforts to integrate the optimizer, lead to the discovery of control and measurement issues.

Project Management

A plant champion was identified at both plants to focus on project completion. A project team supported the plant champion and provided expertise on the combustion monitor, the software optimizer and power plant operations. Meetings were held with the project group once a week to keep all efforts coordinated.

- Plant Champion
  - Direct the project
  - Integrate the equipment
  - Maintain project visibility at the plant
- Project Group
  - Plant champion
  - In-furnace combustion monitor representative
  - Software optimizer representative
  - Power plant expert
- Collaboration
  - Telecoms with project group once a week
  - Weekly action item list
  - Site visits as required

Performance Testing

The performance tests were designed to quantify the benefits of operational changes made by the project. Consistent operating conditions were maintained between the baseline and post balancing tests. Industry accepted ASME PTC procedures provided the basis for the performance tests. The control variable settings were documented for each performance test to determine a repeatable set of boiler conditions. The control variables included: excess air, total air flow, secondary air distribution, fuel flow and mill settings.

Three efficiency calculations were derived from the performance test data:

1. **CO_2/MWh**
   CO_2/MWh provides a direct ratio of the ultimate combustion product relative to the output of the unit.
2. **Controllable Losses**
   Quantify the impact on heat rate from Auxiliary power, Dry Gas Loss, and LOI.
3. **Heat Rate : Heat Loss Method**
   The Heat Loss method considers total energy added to the working fluid vs. calculated losses from each of the major energy loss pathways.

The project duration did not allow for a formal uncertainty and error analysis of the results at each plant. However, quantifying three independent indicators of efficiency should provide statistical validity to the results.

CO_2/MWh

Improvement of unit efficiency as measured by CO_2/MWh is the focus of this project and reflects societal interest in reducing carbon emissions. This metric provides an elegant solution to quantifying efficiency as the only items evaluated for a CO_2 efficiency measurement are the tons of CO_2 out of the stack (CEMS flow meter and constituent analyzer) and the net power produced by the unit. Both of these variables are continuously monitored and relatively easy to quantify. Other efficiency calculations rely on hard-to-measure parameters such as coal energy content or LOI. The CO_2 efficiency metric balances itself as fuel changes since the Higher Heating Value (HHV) of coal is primarily based on the carbon content of the fuel. Thus, a high energy coal will produce both more CO_2 and more power, while poor quality coal will produce less CO_2 and less power. Overall the ratio between the energy of the fuel and CO_2 produced should be conserved.

Controllable Losses

Heat Loss efficiency calculations consider energy added to the working fluid vs. calculated losses from each of the major energy loss pathways. Controllable losses are losses directly attributable to furnace balancing and excess air reductions:

- Reduction in dry gas loss.
- Decrease in auxiliary fan power.
- Change in LOI.

These three losses are relatively easy to measure yet capture most of the effect of combustion balance improvements. Analysis of the Heat Loss impact of these three variables minimizes uncertainties introduced by a comprehensive Heat Loss analysis.

Heat Rate: Heat Loss Method

Traditional power plant performance is expressed by a heat rate value which is often calculated using the Heat Loss method. The Heat Loss method considers energy added to the working fluid vs. calculated losses from each of the major energy loss pathways.

Manual Tuning

The focus of the manual tuning step is to balance combustion across the furnace using the combustion monitor and reduce excess air to realize efficiency gains. Balancing combustion ensures that O_2 depletion zones and temperature hot spots are minimized. O_2 depletion zones and hot spots increase the propensity for boiler slagging which is a critical issue for the plant. Reduction of excess air results in lower fuel consumption (due to less auxiliary power losses and dry gas losses) and thus decreased heat rate and CO_2/MWh. For manual tuning, excess air is reduced to where natural combustion variations would not require constant operator supervision.

Optimizer Tuning

Optimizer tuning begins with integration of optimization software to the DCS to balance combustion and control excess O_2 to improve efficiency. The optimizer uses data from the combustion monitor to actively control fuel and air biases. Once the models have been integrated and tested, the optimizer begins closed loop control of the combustion process. The same performance testing that is conducted for the baseline and manual tests are used to verify optimizer control benefits.

Sustaining Results

Sustaining benefits of balanced combustion and reduced excess O_2 requires:

1. Maintaining visibility of the project at the plant.
2. Determining performance metrics.

3. Monitoring the performance of the boiler by the metrics selected.
4. Adjusting boiler conditions, controls, models or metrics as required.

AEP Results

Manual tuning at AEP occurred at the end of April 2010. Since the performance test the plant has successfully driven combustion control improvements, sustained reductions in the total air flow, and is working with Emerson to integrate the SmartProcess optimizer.

Performance Testing

The baseline performance test was conducted April 15, 2010. The second test, considered the post manual tuning test, was conducted April 29, 2010 after a manual tuning exercise using the Zolo*BOSS*. During both tests, the first hour of testing was devoted to unit stabilization. The subsequent four hours were run at valves-wide-open (VWO) condition which is typical of Unit 3's normal operation. Fuel and ash samples were acquired during the four hour test.

Test Schedule

- 4/15/2010 8:00-13:00 Baseline Test
- 4/27/2010 to 4/28/2010 Tuning Effort
- 4/29/2010 9:00-14:00 Manual Tuning Test

Manual Tuning

Manual tuning work was conducted in conjunction with an AEP corporate boiler tuning specialist, the plant performance engineer and a Black and Veatch boiler engineer. In the course of two days, the group was able to use the Zolo*BOSS*, existing plant sensors, and standard boiler controls to balance combustion in the furnace and subsequently reduce excess air.

<u>Baseline Condition</u>

The following images show the Zolo*BOSS* combustion images before and after balancing. Color is used to represent constituent concentration; in the case of Oxygen, purple is 2% and red is 9%.

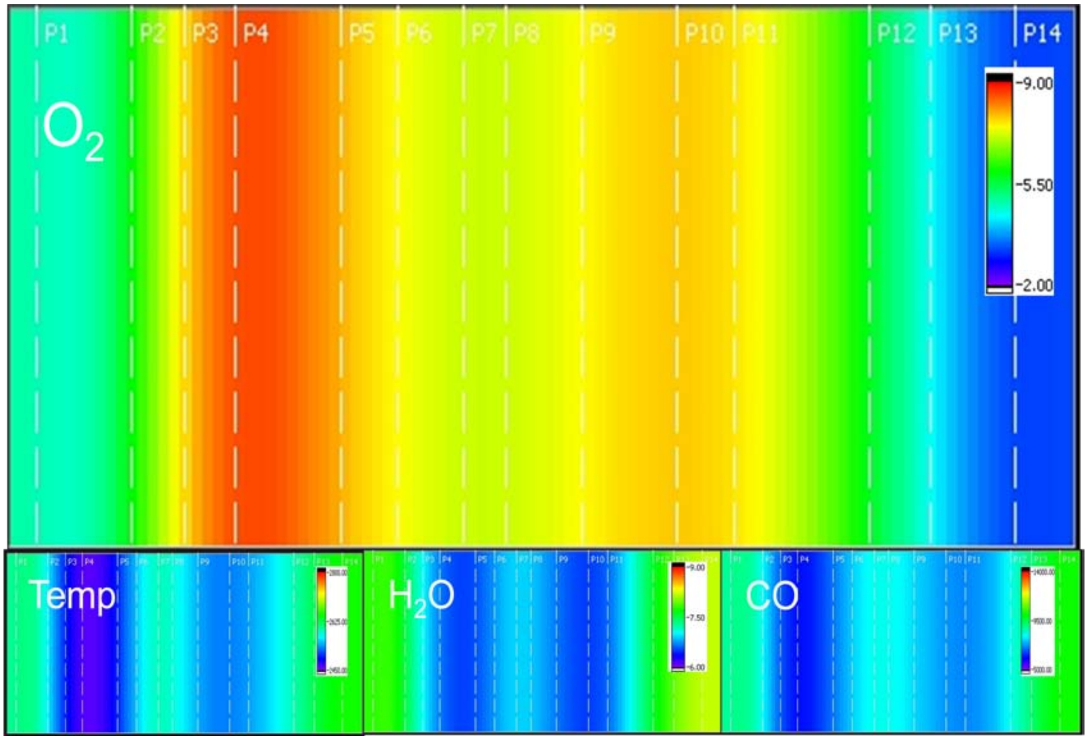

Figure 5: Baseline Performance Test 4/15 9:00-13:00

<u>Manual Combustion Tuning</u>

The process of manual combustion tuning at AEP consisted of balancing combustion and adjusting total air flow. This process involved three steps:

1. Moving excess air to the left and right walls of the boiler.
2. Distributing more fuel to the lower burners.
3. Reducing the total air flow.

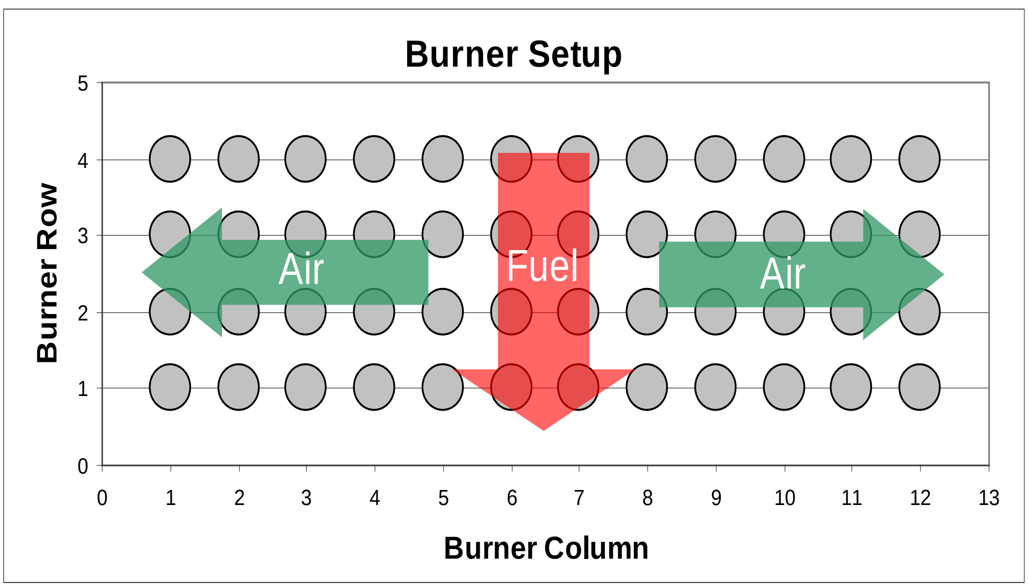

Figure 6: Balancing of fuel and air in the boiler (steps 1 and 2).

Air and Fuel Distribution

As is typical with wall-fired boilers, baseline evaluation from the Zolo*BOSS* system showed low O_2 along the outside walls of the boiler. Thus, air distribution efforts focused primarily on redistributing air from the middle burner shrouds to the right and left sides of the boiler.

This furnace has one common windbox so air movement was accomplished by closing center shrouds to force more air to the left and right sides of the boiler. While it would have been optimal to also open up left and right shrouds, these shrouds were already at maximum open and could not be adjusted further. The figure below gives the change in shroud settings from the baseline test to the performance test.

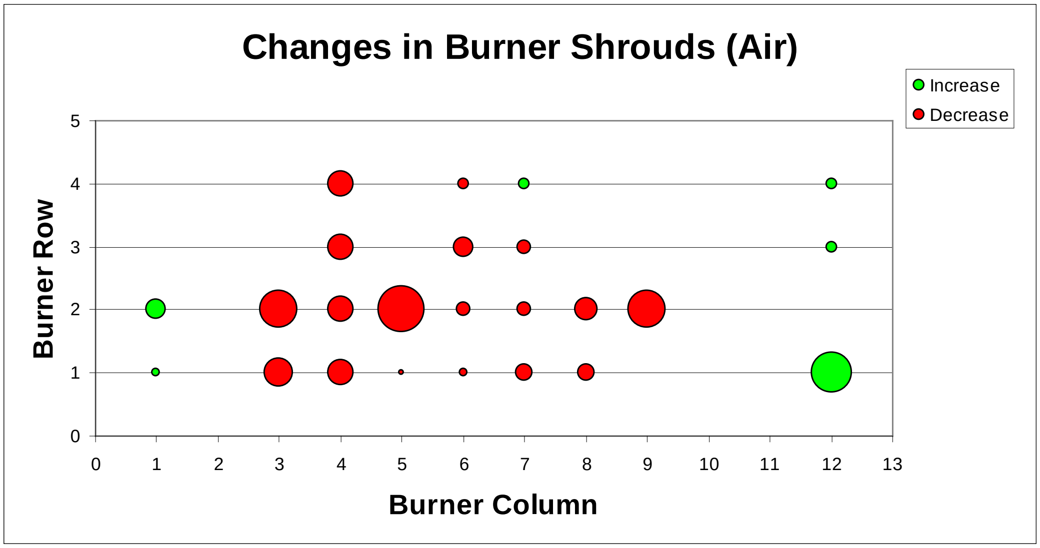

Figure 7: Change in air shroud positions (Green - increase, Red –Decrease, Shroud bias percent change from baseline +28% to -33%)

The final balancing step was to increase fuel delivery to the lower burners by increasing their pulverizer feed rates. Coal feeders 1, 2, 3, 4, 5, and 6 were increased to 100 klb/h coal flow demand, up from roughly 95 klb/h. The remaining feeders decreased to around 87 klb/h coal flow. This was done as a means to stage combustion as this unit does not have Over-Fire Air (OFA). Combustion staging plus excess air reduction resulted in lower NOx formation. Staging also provided more time for combustion to occur before the ash in the flue gas reaches the superheat and reheat pendants. The additional time lowered the flue gas temperature at the pendants which in turn reduced the likelihood of slagging by maintaining flue gas temperatures below the ash fusion temperature.

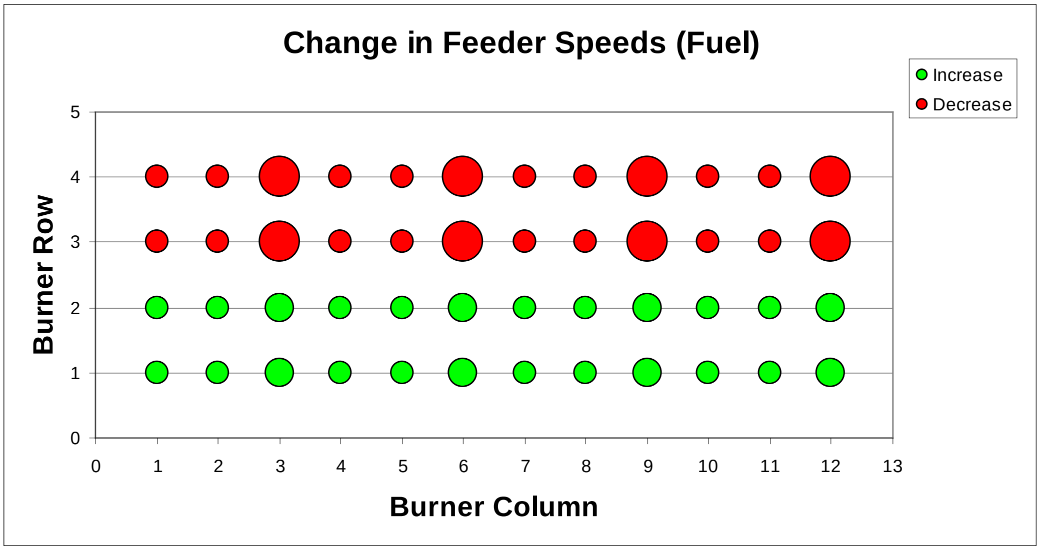

Figure 8: Change in Feeder speed distribution (Green - increase, Red –Decrease, Feeder speed percent change from baseline +8% to -6%)

With combustion balanced, the final tuning step was to safely reduce the overall excess O_2 set point. Working with plant operations, the plant champion, and AEP's corporate combustion expert, it was determined that excess O_2 could be reduced from 3.58% to 3.08% (excess air reduction of ~21% to 17%). This reduction was put into place on the morning of April 29th and the performance test results were quantified.

Manually Tuned Condition

The following Zolo*BOSS* data was measured after combustion balancing and total air flow reduction.

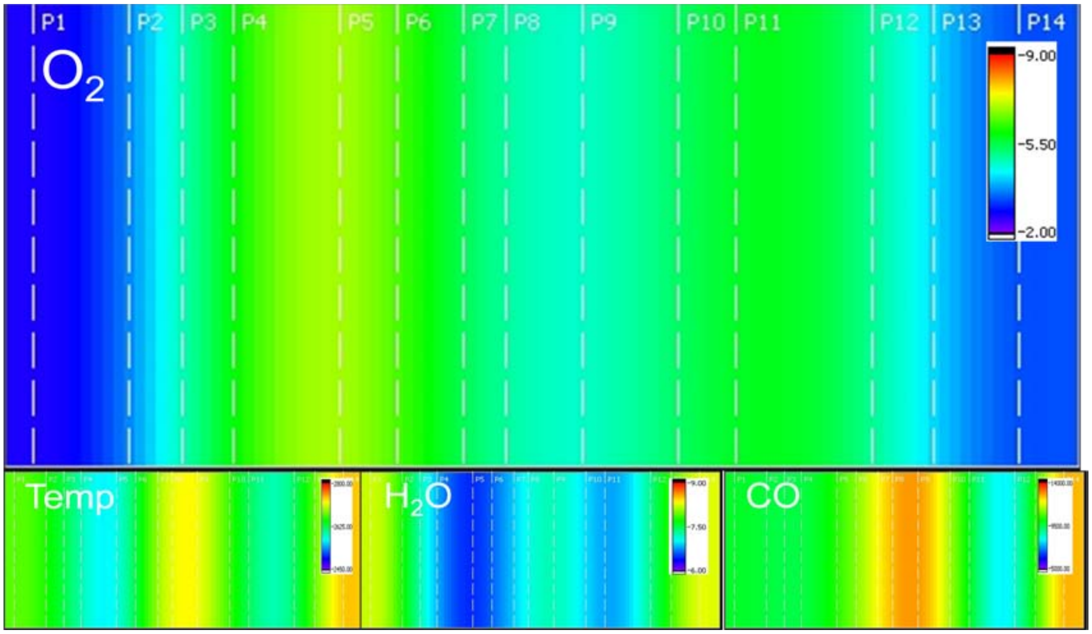

Figure 9: Manual Tuned Condition 4/29 10:00-14:00

Results Summary

The manual balancing and excess air reduction efforts improved boiler efficiency and reduced carbon intensity as measured by CO_2/MWh and provided the plant with fuel and power savings. Operational benefits were verified using three different calculation methods and also confirmed by plant information. A more complete review of the calculations is in Appendix A, but the primary performance results benefits are summarized here.

Three efficiency calculations were used to confirm the results.

1. CO_2/MWh
2. Controllable Losses
3. Heat Rate : Heat Loss Method

Table 2 gives a review of the results along with estimated fuel savings from the efforts.

Table 2: Unit improvement measurements

		Manual Tuning		
	Units	CO_2 CEMS Method	Controllable Losses	Heat-Loss Method
Efficency	**%**	1.80%	0.88%	0.56%
Change in Heat Rate	Btu / kWh	181	88	56
Fuel Savings	tons / yr	73,000	36,000	23,000
CO2 Saving	tons / yr	184,000	90,000	57,000

Heat Rate improvements were corroborated by auxiliary power reductions, increased net load, and decreased SCR inlet NOx as shown in Table 3.

Table 3: Observed pre and post unit performance

				Manual Tuning	
	Units	As-found	Manual tuning	Change (absolute)	Change (relative)
Gross load	MW	1,402.4	1,401.9	-0.5	-0.04%
Net load	MW	1,293.6	1,298.1	4.6	0.35%
Auxiliary power	MW	108.9	103.8	-5.1	-4.7%
Dry gas loss	%	6.306	5.837	-	-7.4%
LOI (Loss on Ignition)	%	1.97	1.96	-0.01	-0.5%
SCR inlet NOx	lb / MMBtu	0.608	0.574	-0.034	-5.7%
CO	ppm	< 10	10.6	-	-
Excess O2	%	3.58	3.08	-0.5	-14.0%

CO_2/MWh Reduction

At AEP the actual CO_2/MWh calculation was determined by use of an NDIR CO_2 analyzer and an ultrasonic stack flow meter. MWh measurements were delivered from the plant's internal PI data server and verified manually on the first performance visit. The only adjustment required was for the contribution of the scrubber which removes SO_2 through a process that produces CO_2 as a byproduct. Pre-tune vs. post tune testing showed a 1.80% decrease in CO_2/MWh. These results are very encouraging as a first order performance test.

Control Loss Method

Dry gas loss represents the bulk of the efficiency improvement at 0.53%. The reduction in auxiliary power by reducing the amount of combustion air delivered to the boiler contributed 0.34%. These reductions were achieved with a minimal change in unburned combustibles. Table 4 provides an overview of results.

Table 4: Controllable losses calculated by the Heat Loss Method.

Specific heat-loss reductions	Units	As-found	Manual tuning	Manual Tuning: Change (relative)	Manual Tuning: Heat rate impact
Dry gas loss	%	6.306	5.837	-7.44%	-0.53%
Unburned Combustible Loss, %	%	0.253	0.248	-1.94%	-0.01%
Aux power reduction					
Forced draft fans	kW	15,688	14,700	-6.30%	-0.09%
Induced draft fans	kW	31,056	28,037	-9.72%	-0.17%
Primary air fans	kW	12,619	12,252	-2.91%	-0.08%
Total aux power reduction	kW	59,363	54,988	-7.37%	-0.34%
				Change in Heat Rate	-0.88%

Heat Rate : Heat Loss Method

The corrected Heat Loss method shows that heat rate improved by 0.56% due to manual tuning

Sustaining Results

John Amos U3 is currently working to integrate the Emerson SmartProcess optimizer. A combination of the visibility provided by the Zolo*BOSS* and the requirements of the optimizer has led to the following updates of Unit 3:

- Shroud control improvement.
  - A combination of power cable crosstalk and control logic issues was identified and corrected by plant personnel.
- Economizer exit O_2 probe calibrations and repairs.
  - A review of excess air imbalances highlighted probes that were not reporting correctly. These probes were calibrated or repaired as needed.
- CO monitors additions and replacements.
  - One CO monitor was available from existing equipment. Two additional monitors were ordered so that each of the three economizer outlets could be measured. The CO probes will be used as an input for the Emerson SmartProcess.

These physical improvements, along with the oversight of plant personal, produced an environment of rigorous control of the combustion process even prior to the full integration of the optimizer. As of the middle of October the plant was confident enough with the control to reduce the excess O_2 from 3.6% to 3.1% (~ excess air 21% to 17%). This represents roughly the same excess air reduction demonstrated in the performance test and is equivalent to a 1-2% CO_2/MWh efficiency improvement.

DTE Results

At DTE, both manual and optimizer tuning was conducted and the plant is currently focused on sustaining benefits achieved by the integration.

Performance Testing

The baseline test was conducted July 27, 2010 to quantify boiler operation at historic fuel and air flow setpoints. The manual tuning test was conducted July 28, 2010 after manually tuning the boiler with the Zolo*BOSS*. Finally, the CombustionOpt optimizer was initialized on July 29, 2010 to balance combustion and bias the total air flow and then a third tuning test was conducted.

Test Schedule:

- 7/27/2010 8:00-12:00 Setup Baseline
- 7/27/2010 12:30-20:30 Baseline Test
- 7/28/2010 7:00-9:00 Manual Tuning
- 7/28/2010 9:00-18:00 Manual Tuning Test
- 7/29/2010 Initiate Optimizer Control
- 7/30/2010 10:00-18:00 Optimizer Test

During all three tests, the first hour of testing was devoted to unit stabilization. The subsequent four hours were run at a repeatable standard condition to test performance. Finally, the unit was set to run for three hours at Valves-Wide-Open (VWO) to quantify turbine performance. Fuel and ash samples were acquired during the four hour performance test set to quantify operational variances.

Manual Tuning

At DTE, plant operators and engineers were familiar with tuning combustion controls using the Zolo*BOSS* system. The training and experience of the staff made possible rapid testing, tuning and re-testing.

<u>Baseline Condition</u>

Baseline conditions were established by setting the air flow to a standard condition prior to this project's introduction, and balancing economizer O_2 readings as needed to mitigate stack CO. Zolo*BOSS* measurements acquired during baseline testing showed a reasonable balance of excess O_2 (a higher spot slight left of center), but left room for improvement in the distribution of temperature and CO. These measurements were encouraging in that excess air could be safely reduced with minimal balancing efforts.

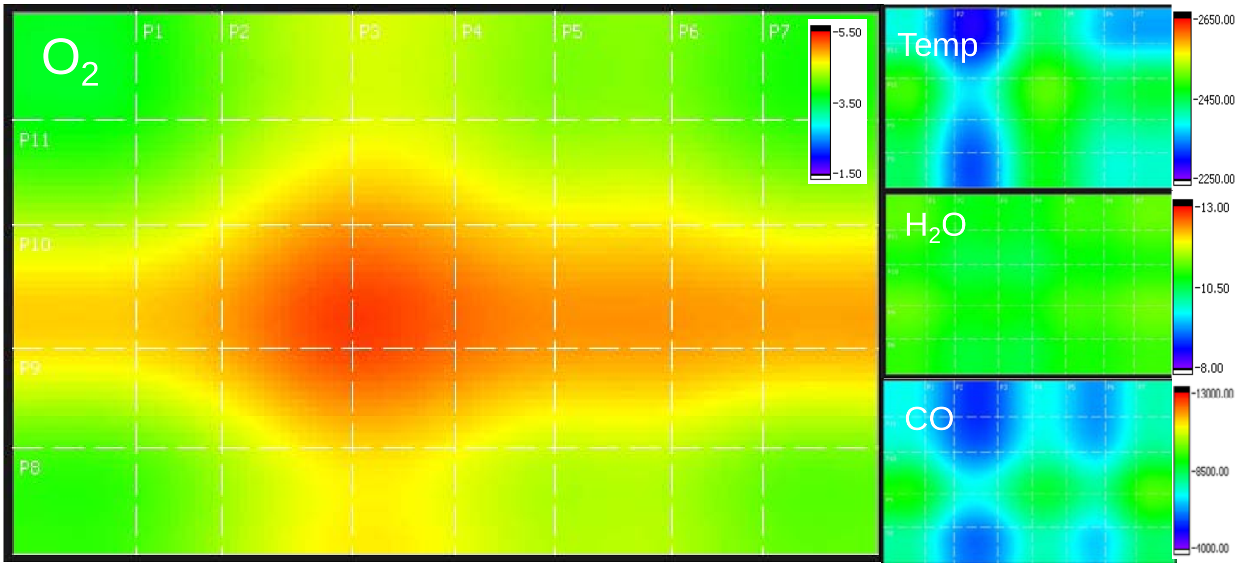

Figure 10: Baseline Performance Test 7/27 13:30-17:30

Manual Combustion Tuning

Manual combustion tuning followed this process:

1. Adjust the front to back and left to right O_2 distribution based on Zolo*BOSS* measurements.
2. Vary shroud positions based on CO and temperature uniformity.
3. Change the total air flow.

Manual tuning was accomplished in less than two hours thanks to staff familiarity with the Zolo*BOSS* and because baseline results already showed reasonable O_2 balance. During tuning air flow was reduced, the O_2 balance was maintained, and the distribution of temperature and CO was improved.

Air and Fuel Distribution

The majority of the manual balancing efforts worked to a) maintain the O_2 balance observed during baseline testing and b) improve CO and temperature balance. The efforts had the desired effect of maintaining O_2 uniformity and improving temperature and CO distributions. For the manual efforts it was not necessary to bias the fuel flows.

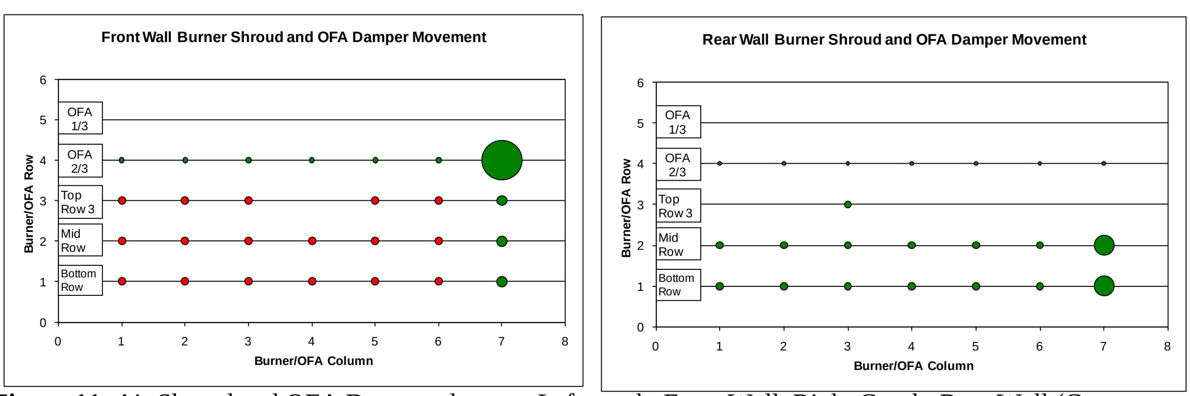

Figure 11: Air Shroud and OFA Damper changes. Left graph: Front Wall, Right Graph: Rear Wall (Green - increase, Red - Decrease, Shroud bias range +11% to -2%)

These changes resulted in evenly distributed combustion as shown in the next section.

Manually Tuned Condition

The following Zolo*BOSS* data was measured after combustion balancing and total air flow reduction.

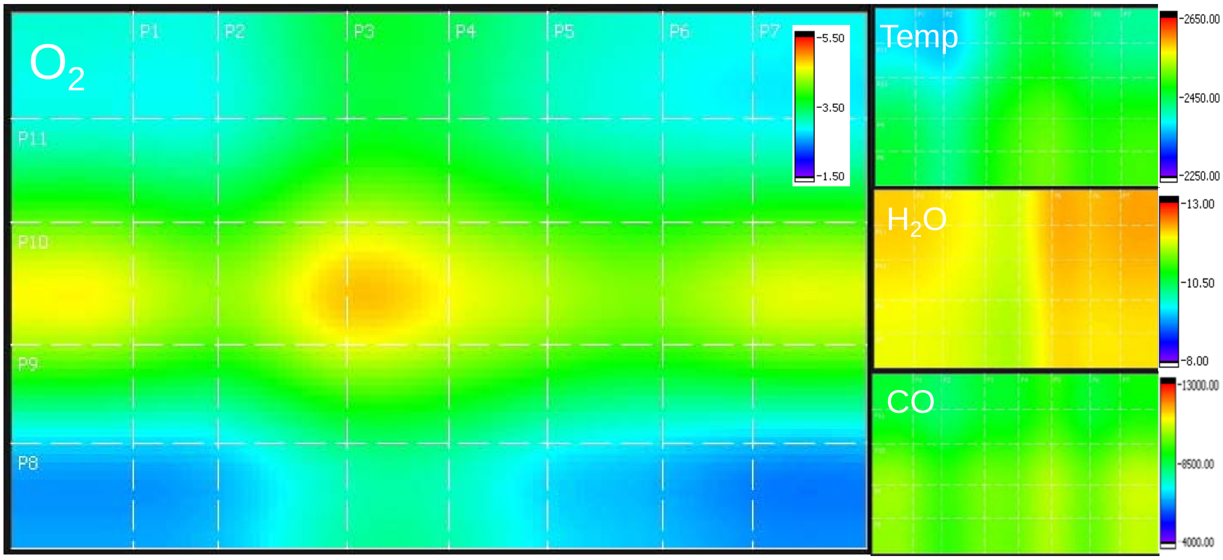

Figure 12: Manual Tuning Performance Test 7/28 10:00-14:00

Optimizer Tuning

Work at DTE showed that an optimizer is most effective when a plant engineer constrains the solution set in which the optimizer searches. The plant engineer used Zolo*BOSS* data to focus shroud and fuel bias changes to sections of the boiler that were imbalanced. For example, if a boiler imbalance was observed in the north-west corner, the optimizer was constrained to address the imbalance by adjusting the column of burners directly underneath the imbalance. The constraints reduced the search space for balanced combustion from forty burners and fourteen OFA ports to three burners and two OFA ports. This decreased the optimization search space and allowed for rapid balancing of the combustion zone.

The process of optimizing combustion at DTE with the NeuCo CombustionOpt system consisted of:

1. Balancing combustion (CO, Temp, and O2) from side to side
    a. Goal : minimize deviations in North Wall Zolo*BOSS* intersection points
    b. Goal : minimize deviations in South Wall Zolo*BOSS* intersection points
2. Balancing combustion (CO, Temp, and O2) from front to back
    a. Goal : minimize the deviations of Zolo*BOSS* paths 8 through 11
3. Adjust total air flow.
    a. Routine: Bias excess air flow based upon the average Zolo*BOSS* CO and O_2, the stack CO, and the DCS excess O2 set point.

These iterative processes were repeated continuously to maintain optimized combustion and efficiency improvements.

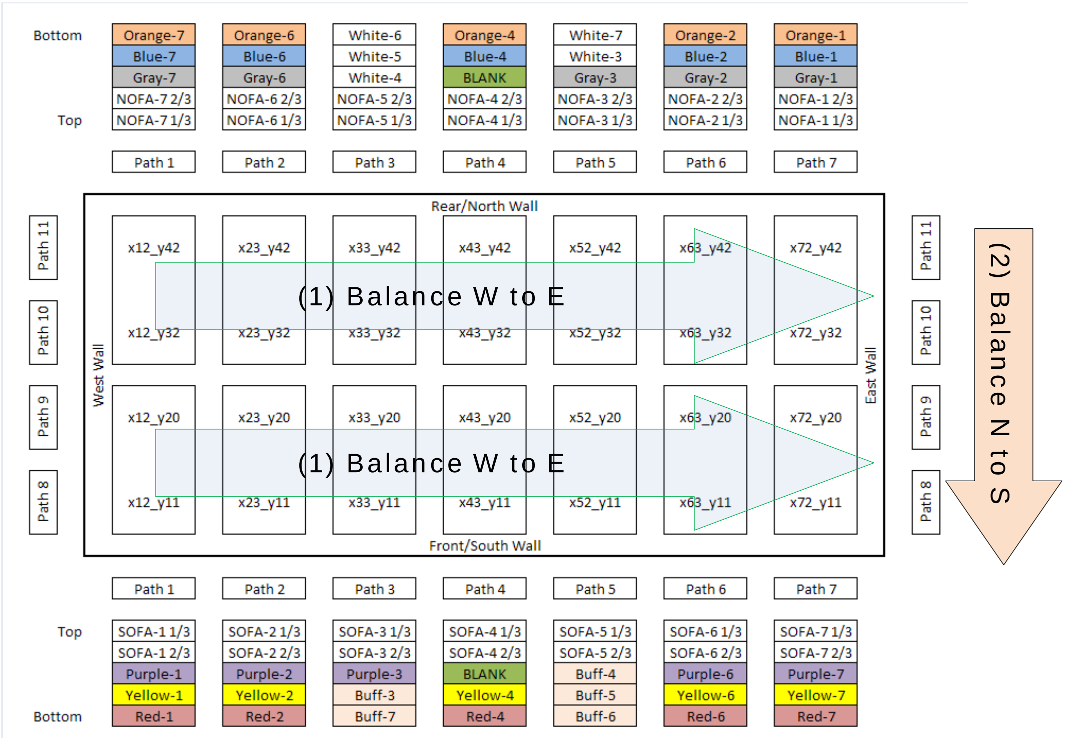

Figure 13: Distribution of Zolo*BOSS* grid measurements relative to burner, OFA, and mill layouts.

Air and Fuel Distribution

The shroud, OFA and burner bias graphics illustrate how the CombustionOpt optimizer actively moved biases in an attempt to stabilize combustion. The optimizer was able to maintain the balance at a further reduced excess air flow.

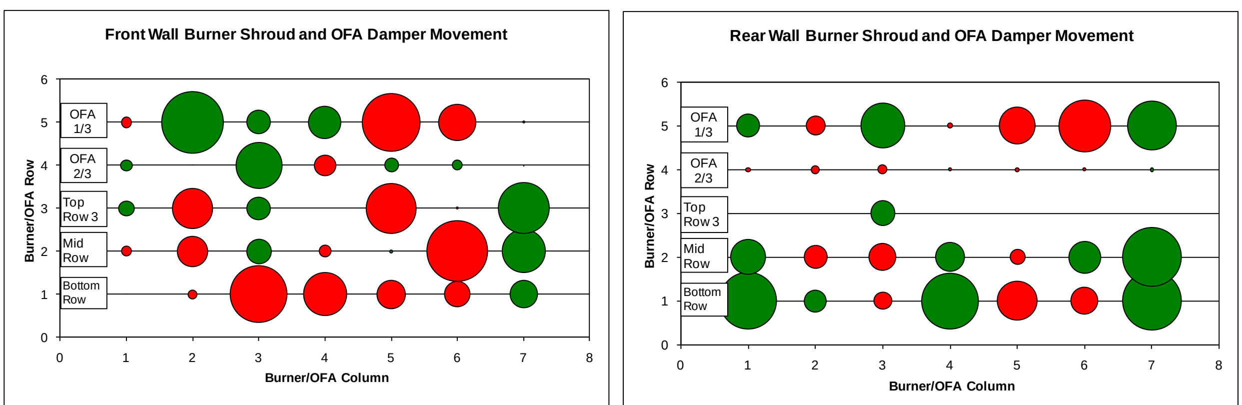

Figure 14: Air Shroud and OFA Damper changes. Left graph: Front Wall, Right Graph: Rear Wall (Green - increase, Red –Decrease, Shroud bias range +20% to -20%)

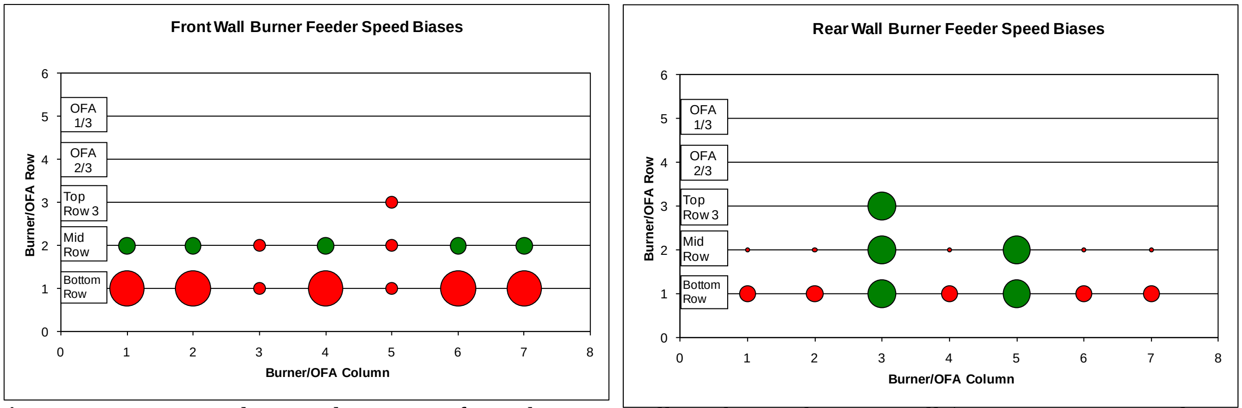

Figure 15: Burner Feeder Speed Biases. Left graph: Front Wall, Right Graph: Rear Wall (Green - increase, Red – Decrease, Feeder speed biases +5% to -6% of master control)

Optimizer Tuned Condition

The following Zolo*BOSS* data was measured during the Optimizer Performance Test.

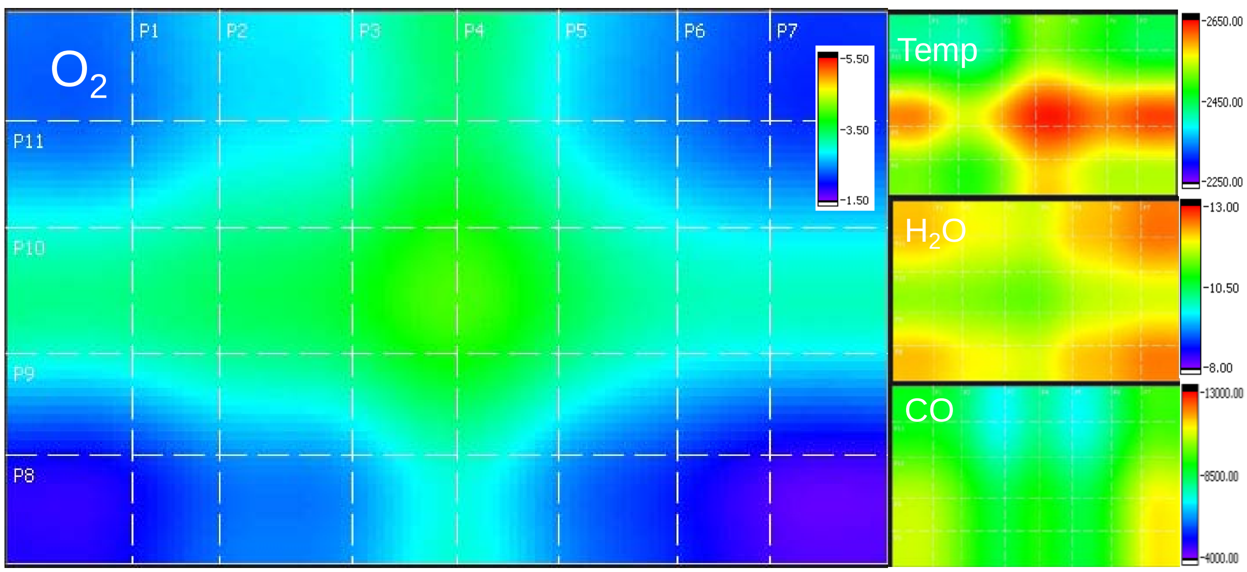

Figure 16: Optimizer Performance Test 7/30 11:00-15:00

Results Summary

Manual and optimizer based tuning improved boiler efficiency and provided the plant with fuel and auxiliary power savings. Operational benefits were verified using three different calculation methods and were also confirmed by plant data. A complete review of the calculations is in Appendix B, the primary results are summarized here.

Three efficiency calculations were used to confirm the results.

1. CO_2/MWh
2. Controllable Losses
3. Heat Rate : Heat Loss Method

Table 5: Unit improvement measurements

		Manual tuning			Optimizer Tuning		
	Units	CO2 CEMS Method	Controllable Losses	Heat-Loss Method	CO2 CEMS Method	Controllable Losses	Heat-Loss Method
Efficiency	%	2.43%	0.57%	0.87%	2.34%	1.55%	1.71%
Change in Heat Rate	Btu/kWh	252	59	90	243	161	177
Fuel Savings	tons/yr	63,000	15,000	23,000	62,000	41,000	45,000
CO2 Savings	tons/yr	127,000	30,000	46,000	122,000	81,000	89,000

Heat Rate improvements were corroborated by auxiliary power reductions as shown in Table 6. Manual and optimizer tuning results are both relative to "As-found" measurements.

Table 6: Observed unit performance pre and post Manual and Optimizer Tuning

					Manual Tuning		Optimizer Tuning	
	Units	As-found	Manual Tuning	Optimizer Tuning	Change (absolute)	Change (relative)	Change (absolute)	Change (relative)
Gross load	MW	648.6	648.6	645.5	-0.1	-0.01%	-3.1	-0.48%
Net load	MW	609.4	611.4	610.1	2.0	0.33%	0.7	0.11%
Auxiliary power	MW	39.3	37.2	35.5	-2.1	-5.3%	-3.8	-9.7%
Dry gas loss	%	7.44	7.14	6.57	-	-4.1%	-	-11.8%
LOI (Loss on Ignition)	%	0.075	0.103	0.082	0.028	37.2%	0.007	9.3%
NOx	lb/MMBtu	0.251	0.202	0.201	-0.049	-19.4%	-0.050	-20.0%
CO	ppm	88.4	78.5	156.6	-9.9	-11.2%	68.2	77.2%
Excess O2	%	4.39	3.23	2.45	-1.15	-26.3%	-1.94	-44.2%

CO_2/MWh

At DTE the actual CO_2/MWh calculation was determined by use of a California Analytic Instruments Series 600 NDIR CO_2 analyzer and a Teledyne Instruments Ultraflow 150 ultrasonic stack flow meter. MWh meter reading were delivered by DTE corporate and verified by the plant's historian records. Manual tuning and optimizer tuning both showed significant reductions of CO_2/MWh of 2.43% and 2.34% respectively. These results show that a 2% reduction in CO_2/MWh is achievable through plant training, an in-furnace combustion monitor, and a software optimizer.

Controllable Losses

Controllable Losses show that heat rate improved by 0.57% from manual tuning and by 1.55% from optimizer tuning. A break out of the losses shows that dry gas loss represents about 2/3 of the efficiency improvements in both manual and optimizer tuning.

Table 7 : Controllable losses calculated by the Heat Loss Method

Specific heat-loss reductions	Units	As-found	Manual Tuning	Optimizer Tuning	Manual Tuning Change (relative)	Manual Tuning Heat Rate Impact	Optimizer Tuning Change (relative)	Optimizer Tuning Heat Rate Impact
Dry gas loss	%	7.44	7.14	6.57	-4%	-0.37%	-12%	-1.05%
Unburned Combustible Loss	%	0.07	0.10	0.08	37%	0.03%	9%	0.01%
Aux power reduction								
Forced draft fans	KW	15,199	14,187	13,152	-7%	-0.06%	-13%	-0.15%
Induced draft fans	KW	6,828	6,447	5,921	-6%	-0.17%	-13%	-0.33%
Primary air fans	KW	6,448	6,412	6,257	-1%	-0.01%	-3%	-0.03%
Total aux power reduction	KW	28,475	27,046	25,330	-5%	-0.23%	-11%	-0.51%
					Change in Heat Rate	**-0.57%**		**-1.55%**

<u>Heat Rate : Heat Loss Method</u>

The corrected Heat Loss method shows that heat rate improved by 0.87% due to manual tuning and by 1.71% due to optimizer tuning.

Sustaining Results

To sustain results at DTE, indicators of performance were identified and monitored weekly to determine if the plant was maintaining efficiency gains over a longer period. The metrics and thresholds were as follows:

Controls	Threshold
Air flow (klb/h)	5900
Balance (StDev ZBTemp)	0.02
Performance	
Fan Power (MW)	27
Dry Gas Loss (%)	7
Efficiency (tons CO_2/MWh)	1.06
NOX Emissions (lb/Mbtu)	0.2

Control and Performance thresholds were determined from performance testing results. If the processed data sets are above thresholds the results are discussed, diagnosed, and corrected when possible. This evaluation technique allows for a focused, simplified approach to monitoring and improving combustion efficiency.

Unfortunately, at the same time these thresholds were enacted the plant had fuel variations that increase slagging in the super heater pendants. To maintain availability, the plant increased air flow and stopped using automated CombustionOpt control. Even with the increased air flow and manual control, the unit has been at reduced loads up until the end of November 2010 when a one week boiler outage occurred. Since the outage, availability with the unit has improved and the plant is modifying how the Zolo*BOSS* and the CombustionOpt system are used to maintain availability.

<u>Unit Operation Moving Forward</u>

DTE corporate boiler experts and the plant champion are working to improve the benefits of the Zolo*BOSS* and the CombustionOpt system given the boiler's propensity to slag. The new models being developed and integrated into the optimizer will have the following priorities:

1. Balance fire box for Temp and CO
2. Maintain Flue Exit Gas Temperature (FEGT) < 2300F using Zolo*BOSS* path 12.
3. Adjust airflow to the boiler

Of these operations, step 1 was previously introduced and has only been slightly modified. Step 2 is a new operational control to reduce slagging in the superheater. This new control logic makes use of Zolo*BOSS* path 12 which is located directly in the superheater area. Path 12 is an ideal FEGT monitor as it is a path average measurement and runs the length of the superheater. 2300F was selected as a point below which slagging would be minimized. Step 3 is currently under manual control, once the plant is comfortable with the first two processes airflow will be controlled based on FEGT. Once fully integrated, this method of boiler control should balance the need for availability while maintaining optimal efficiency

Conclusions & Recommendations

The project successfully demonstrated that a combination of an in-furnace combustion monitor, an optimizer, and plant training can improve efficiency and reduce the CO_2/MWh density. The ability to view the concentration of combustion constituents just above the firing zone provides a better understanding of combustion than can be inferred from standard methods. Both manual and software tuning efforts are enhanced by this information.

Results from the coal-fired power plant study demonstrated a reduction in CO_2/MWh through combustion optimization of 2%. Controllable Losses show a $2.1 million/year savings on coal costs at Amos and a $1.6 million/year savings at Belle River. Implementing this technology across the U.S. fleet of power plants would reduce CO_2 by 37,000,000 tons per year saving a total of $670,000,000 in coal costs.[1,2] If implemented, this CO_2 reduction represents more CO_2-free energy than all of the currently installed solar and wind power in the United States at a fraction of the cost. (1/100th the cost of large scale solar PV and 1/25th the cost of large scale wind installations).

Lessons Learned

- Strong overall project management is key.
- A cohesive implementation team is required (plant & partners).
- An involved plant champion at the site is necessary.
- Corporate commitment and support is essential for success.
- For the project to be successful, plant staff (including operators) must buy-in.
- Plant training procedures should be tailored to work with plant culture and resources.
- Plant training should be delivered by an expert in the power industry.
- A live demonstration (prior to tuning efforts) of balancing combustion using the in-furnace combustion monitor is beneficial for equipment adoption and manual tuning.
- Manual tuning efforts help guide optimizer model development.
- Early results generate momentum and acceptance of the project at the plant.
- Remote access to data / systems is required.
- Project duration may need to be > 1 year, especially for sites without an existing software optimizer.

Recommendations

- The full integration of an in-furnace combustion monitor, combustion optimizer, and plant training should be validated on other boiler types (tangentially-fired, cyclone, front-wall fired), sizes (200-1000 MW), steam conditions (super-critical and sub-critical) and fuels (sub-bituminous, bituminous, lignite and bio-mass).
- A two year project duration will allow adequate time to both achieve results and sustain results.
- Plant efficiency training requires on-going reinforcement to incorporate these changes into the plant culture.
- A project template for each utility should be developed with utility corporate representation that includes standardized and consistent hardware and software platforms and training to facilitate fleet roll-out.

Appendix A: AEP Performance Analysis

Results of the baseline and manual tuning tests are in Table 8. In summary, the pre-test vs. post test results show that excess air was reduced by about 0.5 percentage points from 3.58% during the baseline test to 3.08% during the post-tuning test. This reduced CO_2/MWh intensity by 1.80%, controllable losses by an estimated 0.88%, and the net Heat Loss method by 0.56%. These reductions were achieved with no appreciable increase in CO because combustion balance was improved between the two tests.

Table 8: Summary of results

	Baseline Test	Manual Tuning Test	Change	Change, %
Gross Load, MW	1402.4	1401.9	-0.5	-0.04%
Net Load, MW	1293.6	1298.1	4.6	0.35%
Auxiliary Power, MW	108.9	103.8	-5.1	-4.7%
CO2 Intensity, Tons CO2/MWh	1.000	0.981	-0.020	-1.95%
CO2 Intensity (Adj for Scrubber), Tons CO2/MWh	0.984	0.967	-0.018	-1.80%
Raw Net Unit Heat Rate Heat Loss, Btu/kWh	10041	10012	-28.9	-0.29%
Net Unit Heat Rate Heat Loss, Btu/kWh	10041	9985	-56.2	-0.56%
Net Unit Heat Rate I/O, Btu/kWh	9932	9692	-240.5	-2.4%
Boiler Efficiency I/O, %	89.1%	91.3%	2.25	-
CO Avg, PPM	< 10	10.6	-	-

Controllable Losses	Baseline Test	Manual Tuning Test	% Heat Rate Change
Dry Gas Loss, %	6.3%	5.8%	-0.53%
Unburned Combustible Loss, %	0.3%	0.2%	-0.01%
Aux Power (Fans only), KW	59363	54988	-0.34%
Total	-	-	-0.88%

A detailed breakdown of the measured performance changes between the two test sets is given below.

Boiler Efficiency

Boiler efficiency is calculated using the Heat Loss method in this report. Heat rate using the Input/Output method was not presented because it is generally considered less accurate. It is included here to corroborate CO_2/MWh Intensity, Controllable Loss, and Heat Loss findings.

Heat Loss efficiency considers energy added to the working fluid plus calculated losses. The energy imparted to the working fluid is determined from the energy in the water entering the boiler vs. the energy in the steam leaving the boiler. The Input/Output method uses the energy in the steam leaving the boiler divided by the energy input from fuel as determined from the gravimetric weight and the higher heating value of the coal. For both methods, additional fuel and ash sampling was performed during the performance tests to support the calculations.

Table 9: Boiler efficiency summary

	Baseline Test	Manual Tuning Test	Change
Boiler Efficiency H/L, %	88.1%	88.4%	0.3%
Boiler Efficiency H/L(Corr for H2O in fuel), %	88.1%	88.6%	0.5%
Boiler Efficiency I/O, %	89.1%	91.3%	2.2%

Net Unit Heat Rate

Unit heat rate is calculated by the same two methods as boiler efficiency. The net unit heat rate change as measured by the Heat Loss method is 0.56%. This value is lower than the controlled loss improvement of 0.88% reported for losses impacted by our tuning efforts. The difference is due to other uncontrolled unit changes. The raw net unit heat rate is shown in the table along with the net unit heat rate corrected for fuel and turbine condition changes.

Table 10: Net Unit Heat Rate summary

	Baseline Test	Manual Tuning Test	Change	Change, %
Raw Net Unit Heat Rate Heat Loss, Btu/kWh	10041	10012	-28.9	-0.29%
Net Unit Heat Rate Heat Loss, Btu/kWh	10041	9985	-56.2	-0.56%
Net Unit Heat Rate I/O, Btu/kWh	9932	9692	-240.5	-2.4%

Boiler Losses

Boiler efficiency determined using the heat loss method has the added benefit of highlighting the major boiler losses. With a focus on balancing combustion and lowering excess air, the majority of the efficiency gain is realized in the dry gas loss. The dry gas loss is a function of excess air quantity supplied to the boiler and the temperature of the flue gas leaving the boiler. Boiler tuning improved the dry gas loss contribution to unit heat rate by 0.534% as shown in Table 11.

Table 11: Individual boiler losses (Heat Loss Method)

	Boiler Losses, Heat Loss Method			
Individual Boiler Losses	Baseline Test	Manual Tuning Test	Change	Change, %
Dry Gas Loss	6.3%	5.8%	-53.4	-0.53%
H2 & H2O In Fuel Loss	4.9%	5.1%	21.8	0.22%
Moisture in Air Loss	0.1%	0.1%	-0.6	-0.01%
Unburned Combustible Loss	0.3%	0.2%	-0.6	-0.01%
Other Minor Losses	0.4%	0.4%	-0.2	0.00%
Total Losses	-	-	-32.9	-0.33%

Auxiliary Power

Auxiliary power not consumed by the unit is available for export to the grid and the auxiliary power savings from the tuning exercise were significant. Fan power usage fell by 4.375 MW in the post-tuning test compared to the baseline test as seen in Table 12. The reduction in fan power accounts for the majority of the total 5.1 MW reduction of auxiliary power consumption.

The power required by the pulverizers remained largely unchanged or slightly increased during the post-tuning test. The slight increase could be due to the slightly poorer fuel quality in the second test.

Table 12: Summary of combustion related auxiliary power usage

Auxiliaries	Baseline Test	Manual Tuning Test	Change	Change, %
Foreced Draft (FD) Fans, KW	15688	14700	-989	-6.3%
Induced Draft (ID) Fans, KW	31056	28037	-3019	-9.7%
Primary Air (PA) Fans, KW	12619	12252	-367	-2.9%
Total Fan Usage, KW	59363	54988	-4375	-7.4%

Turbine Cycle Summary

Turbine cycle heat rate is an indication of the entire turbine cycle performance including the turbines, feedwater heaters, pumps, and the condenser. Combustion tuning should have no impact on turbine cycle performance; however turbine side testing is necessary to ensure that the results are not biased by unrelated changes in turbine cycle performance.

Based on the tests conducted at turbine valves-wide-open, the turbine cycle performance did not unfairly benefit the post-tuning test. Turbine cycle performance was worse in the second test by about 43 Btu/kWh in unit heat rate.

Table 13: Turbine cycle heat rate at Valves-Wide-Open

Turbine Cycle Performance	Baseline Test	Manual Tuning Test	Change	Change, %	% Change in Heat Rate	Abs. Change in Unit Heat Rate, Btu/kWh
VWO Turbine Heat Rate, Btu/kWh	8159	8194	34.9	0.4283%	0.4283%	43.0

The individual turbine cycle corrections are shown in the figure below. Condenser back pressure was lower in the second test due to cooler ambient conditions. Reheat temperature during the second test was improved, but the heat rate gain was offset by the increase in reheat attemperating spray flow. The sum total of identified turbine cycle corrections was -41. 8 Btu/kWh.

Table 14: Turbine cycle parameters

Turbine Cycle Parameters	Baseline Test	Manual Tuning Test	Change	Change, %	% Change in Heat Rate	Abs. Change in Unit Heat Rate, Btu/kWh
Condenser back pressure, in HgA	3.02	2.76	-0.26	-8.63%	-0.40%	-40.05
Throttle Pres, PSIG	3671.9	3654.9	-17.0	-0.46%	0.03%	2.90
Throttle Temp, deg F	999.7	998.7	-1.0	-0.10%	0.02%	2.09
RH Temp, deg F	985.5	994.0	8.5	0.86%	-0.13%	-12.79
Main steam attemp spray, klb/h	170.3	179.4	9.1	-	0.00%	0.00
Reheat Steam attemp spray, klb/h	0.0	92.8	92.8	-	0.14%	13.60
Final Feedwater Temperature	523.0	526.7	3.76		-0.08%	-7.54
Total	-	-	-	-	-0.42%	-41.80

Emissions

Manual CO and NOx readings were taken at nine locations across the economizer exit duct during the two tests. The average readings are shown in Parts Per Million (ppm) and converted to a pound-per-hour basis (for NOx) and the more traditional pound-per-million Btu for comparison purposes. Table 15 below shows that NOx was reduced by over 5% on a lb/mmBtu basis while CO remained largely unchanged.

Table 15: NOx and CO emission comparison

	Baseline Test	Manual Tuning Test	Change	Change, %
Manual NOx Readings, ppm	431	419	-11.7	-2.72%
Manual NOx Readings (ppm), Lb/h	8366	7891	-475.0	-5.68%
Manual NOx Readings (ppm to lb/mmBtu)	0.608	0.574	-0.034	-5.67%
CO Avg, PPM	< 10	10.6	-	-

Fuel and ash Samples

Fuel sample results showed that the heating value of the coal in the post-tuning test was slightly worse than the fuel used in the baseline test. The moisture content of the fuel in the second test was higher by 1.46%. The higher moisture consumes energy to vaporize the moisture during the combustion process. One can conclude that fuel differences between the two tests did not unfairly bias the results in favor of the post-tuning test.

Table 16: Coal sampling results

Coal Quality	Baseline Test	Manual Tuning Test
Coal Higher Heating Value, Btu/lb	12495	12274
Ash Content, %	10.83	10.53
Carbon Content, %	70.21	69.55
Chlorine Content, %	0.06	0.06
Hydrogen Content, %	4.63	4.59
Moisture Content, %	5.35	6.81
Nitrogen Content, %	1.18	1.17
Oxygen Content, %	4.76	4.72
Sulfur Content, %	2.97	2.57

Ash sampling is required to verify that unburned carbon in ash did not increase with the reduction in excess air. Combustible material that fails to burn and produce usable energy in the boiler is considered a loss and is specifically accounted for in the heat loss method as Loss-On-Ignition (LOI). The LOI value includes carbon in ash plus all other combustibles.

We could only obtain economizer ash samples due to equipment constraints. Table 17 shows the LOI levels were largely unchanged between tests.

Table 17: Ash sampling results

Hopper #	Baseline Test	Manual Tuning Test
1	-	-
2	0.20%	-
3	3.61%	1.86%
4	0.92%	-
5	3.17%	2.05%
6	-	-
	-	-
Average LOI	1.97%	1.96%

Appendix B: DTE Performance Analysis

Results of the baseline, manual tuning and optimizer tuning are in Table 18. In summary, the results show that the reduction in air from 6313 klb/h to 5926 in manual tuning and then 5483 was sustainable by maintaining balanced combustion at the reduced flow conditions. These results are supported by the fact that auxiliary measurements showed minimal change CO and LOI while heat rate and NOx savings were readily realized.

Table 18: Summary of results

					Manual Tuning		Optimizer Tuning	
Units		**Baseline**	**Manual Tuning**	**Optimizer Tuning**	**Change (absolute)**	**Change (relative)**	**Change (absolute)**	**Change (relative)**
MW	**Gross Load, MW**	648.6	648.6	645.5	-0.078	-0.01%	-3.120	-0.48%
MW	**Net Load, MW**	609.4	611.4	610.1	2.017	0.33%	0.687	0.11%
MW	**Auxiliary Power, MW**	39.3	37.2	35.5	-2.095	-5.33%	-3.807	-9.70%
Btu/kWh	**Raw Net Unit Heat Rate H/L**	10469	10354	10291	-115	-1.10%	-178.1	-1.70%
Btu/kWh	**Corrected Net Unit Heat Rate H/L**	10357	10267	10180	-90	-0.87%	-177	-1.71%
Btu/kWh	**Net Unit Heat Rate I/O**	10551	10373	-	-178	-1.68%	-	-
Btu/kWh	**Corrected HHV Net Unit Heat Rate I/O**	10551	10473	10427	-78	-0.74%	-124.303	-1.18%
lb/MBtu	**NOx**	0.2513	0.2025	0.2010	-0.0488	-19.43%	-0.050	-20.02%
%	**CO2**	9.29	9.55	10.21	0.26	2.82%	0.927	9.99%
PPM	**CO**	88	78	157	-10	-11.18%	68.200	77.18%
	CO2 Intensity, Tons CO2/MWh	1.069	1.043	1.044	-0.03	-2.43%	-0.02	-2.34%
%	**Average O2**	4.39%	3.23%	2.45%	-1.15%	-26.31%	-0.019	-44.18%
klb/h	**Total Boiler Air Flow**	6313	5926	5483	-387	-6.13%	-830	-13.14%

				Manual Tuning	**Optimizer Tuning**
Combustion Improvement Summary	**Baseline**	**Manual Tuning**	**Optimizer Tuning**	**Change in Heat Rate (Relative)**	**Change in Heat Rate (Relative)**
Dry Gas Loss, %	7.44%	7.14%	6.57%	-0.37%	-1.05%
Unburned Combustible Loss, %	0.07%	0.10%	0.08%	0.03%	0.01%
Aux Power (Fans only), KW	28475	27046	25330	-0.23%	-0.51%
Total	-	-	-	-0.57%	-1.55%

A detailed breakdown of the measured performance changes between the two test sets is given below.

Boiler Efficiency

Boiler efficiency is calculated using the Heat Loss method in this report. Heat rate using the Input/Output method was not presented because it is generally considered less accurate. It is included here to corroborate CO_2/MWh Intensity, Controllable Loss, and Heat Loss findings.

Heat Loss Heat Loss efficiency considers energy added to the working fluid plus calculated losses.. The energy imparted to the working fluid is determined from the energy in the water entering the boiler vs. the energy in the steam leaving the boiler. The Input/Output method uses the energy in the steam leaving the boiler divided by the energy input from fuel as determined from the gravimetric weight and the higher heating value of the coal. Additional fuel and ash sampling was performed during the performance tests to support all calculations. Both methods agree that boiler efficiency improved after the manual tuning exercise and even more after the optimizer tuning as can be seen in Table 19

Table 19: Boiler efficiency summary

Boiler efficiency summary	**Baseline**	**Manual Tuning**	**Optimizer Tuning**
Boiler Efficiency H/L, %	83.1%	83.5%	84.0%
Fuel Corrected Boiler Efficiency H/L, %	83.9%	84.2%	84.8%
Fuel Corrected Boiler Efficiency I/O, %	81.1%	81.2%	81.7%

Net Unit Heat Rate

Unit heat rate is calculated by the same two methods as boiler efficiency. The net unit heat rate change as measured by the Heat Loss method is 0.87% for the manual tuning and 1.71% for optimizer tuning. The raw net unit heat rate is shown in the table along with the net unit heat rate corrected for fuel and turbine boundary condition changes.

Table 20: Net Unit Heat Rate summary

				Manual Tuning		Optimizer Tuning	
	As Found	Manual Tuning	Optimizer Tuning	Change (Absolute)	Change (Relative)	Change (Absolute)	Change (Relative)
Raw Net Unit Heat Rate Heat Loss, Btu/kWh	10469	10354	10291	-115	-1.10%	-178	-1.70%
Corrected Net Unit Heat Rate Heat Loss, Btu/kWh	10388	10297	10210	-91	-0.88%	-178	-1.71%
Raw Net Unit Heat Rate I/O, Btu/kWh	10551	10373	N/A	-178	-1.68%	N/A	N/A
Net Unit Heat Rate I/O, Btu/kWh (corr HHV)	10551	10473	10427	-78	-0.74%	-124	-1.18%

Boiler Losses

Boiler efficiency determined using the heat loss method has the added benefit of highlighting the major boiler losses. With a focus on balancing combustion and lowering excess air, the majority of the efficiency gain is realized in the dry gas loss. The dry gas loss is a function of excess air quantity supplied to the boiler and the temperature of the flue gas leaving the boiler. Manual boiler tuning improved the dry gas loss contribution to unit heat rate by 0.37%. Optimizer tuning improved the dry gas loss by 1.05% as shown in Table 21.

Table 21: Individual boiler losses (Heat Loss Method)

				Manual Tuning		Optimizer Tuning	
Individual Boiler Losses	Baseline	Manual Tuning	Optimizer Tuning	Change (absolute)	Change (relative)	Change (absolute)	Change (relative)
Dry Gas Loss	7.44%	7.14%	6.57%	-0.31	-0.37%	-0.88	-1.05%
H2 & H2O In Fuel Loss	7.18%	6.99%	7.20%	-0.19	-0.23%	0.02	0.02%
Moisture in Air Loss	0.27%	0.26%	0.24%	-0.02	-0.02%	-0.03	-0.04%
Unburned Combustible Loss	0.07%	0.10%	0.08%	0.03	0.03%	0.01	0.01%
Other Misc Losses	1.70%	1.71%	1.73%	0.01	0.01%	0.03	0.03%
Auxiliary Power (Fans), KW	28475	27046	25330	-5.02%	-0.23%	-11.05%	-0.51%

Auxiliary Power

Auxiliary power not consumed by the unit is available for export to the grid. The auxiliary power savings from the tuning exercise were significant. Fan power usage fell by 1.43 MW during manual tuning and 3.15 MW during optimizer tuning when compared to baseline conditions as seen in Table 22.

Table 22: Summary of combustion related auxiliary power usage

				Manual Tuning		Optimizer Tuning	
Auxiliary Power	Baseline	Manual Tuning	Optimizer Tuning	Change (absolute)	Change (relative)	Change (absolute)	Change (relative)
Induced Draft (ID) Fans, KW	15199	14187	13152	-1012	-6.66%	-2047	-13.47%
Forced Draft (FD) Fans, KW	6828	6447	5921	-381	-5.58%	-908	-13.29%
Primary Air (PA) Fans, KW	6448	6412	6257	-36	-0.56%	-191	-2.96%
Total Fan Power, KW	28475	27046	25330	-1429	-5.02%	-3146	-11.05%

Turbine Cycle Summary

Turbine cycle heat rate is an indication of the entire turbine cycle performance including the turbines, feedwater heaters, pumps, and the condenser. Turbine testing is necessary to ensure that the unit performance results are not biased by unrelated changes in turbine cycle performance.

Based on the tests conducted at turbine valves-wide-open, the turbine cycle performance minimally contributed to testing results. Corrected turbine cycle performance was worse in the manual tuning test by about 10.8 Btu/kWh in unit heat rate and 43.1 Btu/kWh better during the closed-loop optimizer efforts as shown in Table 23.

Table 23: Turbine cycle heat rate at Valves-Wide-Open

Turbine Cycle Performance	Baseline	Manual Tuning	Optimizer Tuning	Manual Tuning Change (absolute)	Manual Tuning Change (relative)	Optimizer Tuning Change (absolute)	Optimizer Tuning Change (relative)
Turbine Heat Rate, Btu/kWh	8552	8531	8492	-0.26%	-27.0	-0.75%	-78.1
Total Turbine Corrections, Btu/kWh	-99.9	-70.4	-72.6	0.36%	37.9	0.33%	35.0
Corrected Turbine Cycle Heat Rate, Btu/kWh	8453	8461	8419	0.10%	10.8	-0.41%	-43.1

The individual turbine cycle corrections are shown in the figure below for the turbine valves-wide-open tests. The corrections are intended to correct turbine cycle performance back to design by accounting for boundary condition changes that are not the fault of the turbine. Correcting each turbine test back to design conditions removes external influences on turbine performance and allows the turbine cycle to be fairly evaluated between tests. The turbine corrections were similar in all three tests as expected due the short duration between tests.

Table 24: Turbine cycle parameters

Turbine Cycle Parameters	Design	Baseline	Manual Tuning	Optimizer Tuning	Baseline Heat Rate Correction	Manual Tuning Heat Rate Correction	Optimizer Tuning Heat Rate Correction
Condenser back pressure avg, in HgA	1.50	2.27	2.24	2.26	-43.0	-37.9	-43.0
Throttle Pres, PSIG	2400	2380	2390	2374	-5.4	-2.4	-7.4
Throttle Temp, deg F	1005	996	1002	1009	-17.51	-5.44	5.42
RH Temp, deg F	1000	998	1004	1012	22.6	27.6	18.4
Main steam attemp spray, klb/h	0	9.1	10.1	12.2	-0.5	-0.4	-0.6
Reheat Steam attemp spray, klb/h	0	126.9	121.9	103.4	-57.9	-54.0	-47.9
Final Feedwater Temperature	481.3	484.0	483.9	482.9	1.7	2.3	2.5
Total					-99.9	-70.4	-72.6

Emissions

Table 25 shows that NOx decreased by about 20% in both manual and CombustionOpt tuning efforts. It is conjectured that NOx did not decrease further during CombustionOpt testing because less air was being delivered through the OFA ports even though the shroud set points were largely unchanged. Should the reduced OFA flow become a concern in the future, the shroud set points on the burners could be reduced to force more air to the OFA ports.

The CO measured during the post-tuning testing showed reduced or minimal increases in CO over the baseline test. Additionally, the unit did not show increased slagging or unburned carbon in ash. CO measurements also did not exceed regulatory limits.

Table 25: NOx and CO emission comparison

Emissions	Baseline	Manual Tuning	Optimizer Tuning	Manual Tuning Change (absolute)	Manual Tuning Change (relative)	Optimizer Tuning Change (absolute)	Optimizer Tuning Change (relative)
NOx, lb/MBtu	0.2513	0.2025	0.2010	-0.049	-19.43%	-0.050	-20.02%
CO, PPM	88	78	157	-10	-11.18%	68.200	77.18%

Fuel and ash Samples

Fuel sample results showed that the heating value of the coal in the post-tuning test and CombustionOpt test were higher than the fuel used in the baseline test. The heating value of the fuel is a measure of the amount of energy available for combustion. The moisture content of the fuel was slightly higher in the baseline test than in the other two tests. The higher moisture consumes energy to vaporize the moisture during the combustion process. The slight differences in fuel have been accounted for in the performance results.

Table 26: Coal sampling results

	Baseline	Manual Tuning	Optimizer Tuning
Higher Heating Value (HHV), Btu/lb	9186	9298	9287
Ash In Fuel, %	3.83	3.79	4.16
Carbon In Fuel, %	53.11	53.14	54.14
Chlorine In Fuel, %	0.00	0.00	0.00
Hydrogen In Fuel, %	3.76	3.71	3.88
Moisture In Fuel, %	26.03	25.68	25.55
Nitrogen In Fuel, %	0.70	0.73	0.71
Oxygen In Fuel, %	12.26	12.61	11.23
Sulfur In Fuel, %	0.33	0.35	0.33

Ash sampling is required to verify that unburned carbon in ash did not increase with the reduction in excess air. Combustible material that fails to burn and produce usable energy in the boiler is considered a loss and is specifically accounted for in the heat loss method as Loss-On-Ignition (LOI). The LOI value includes carbon in ash plus all other combustibles. Table 27 shows the LOI levels were minimally changed between tests.

Table 27: Ash sampling results

	Baseline	Manual Tuning	Optimizer Tuning
LOI Econ, %	0.13%	0.15%	0.16%
LOI Precip, %	0.32%	0.29%	0.31%
LOI Avg, %	0.22%	0.22%	0.24%
UNB In Ash Econ, %	0.04%	0.04%	0.05%
UNB In Ash Precip, %	0.11%	0.16%	0.11%
UNB In Ash Tot, %	0.07%	0.10%	0.08%

Appendix C: Progress Summary

Project tasks status based on the scope of work under Purchase Order RES 1000046.

Phase I – Plant Integration

Task 1 – Project Management
 Subtask 1.1 – COMPLTE. Reports were produced in compliance with Project Management Practices.
 Subtask 1.2 – COMPLTE. Reports detailing project progress was delivered monthly since the project inception.

Task 2 – Site Selection
 Subtask 2.1 – COMPLETE. Two sites selected for demonstration.
  AEP John Amos U3 < 11/2009 DTE Belle River U2 < 11/2009
 Subtask 2.2 – COMPLETE. Delineation of available equipment and equipment to be purchased.
  AEP John Amos U3 12/2009 DTE Belle River U2 < 11/2009

Task 3 – Partner selection
 Subtask 3.1 – COMPLETE. Partner Selection.
  AEP John Amos U3 < 11/2009 DTE Belle River U2 < 11/2009
 Subtask 3.2 – COMPLETE. CO_2 monitor.
  AEP John Amos U3 12/2009 DTE Belle River U2 < 11/2009

Task 4 – Test plan
 Subtask 4. 1 – COMPLETE. Definition of baseline performance tests. .
  AEP John Amos U3 3/2010 DTE Belle River U2 2/2010

Task 5 – Combustion Equipment Procurement.
 Subtask 5.1 – COMPLETE. Combustion monitoring equipment procured.
  AEP John Amos U3 < 11/2009 DTE Belle River U2 < 11/2009

Task 6 – Performance Engineer
 Subtask 6.1 - COMPLETE. Identify site engineer.
  AEP John Amos U3 < 11/2009 DTE Belle River U2 < 11/2009

Task 7 – Plant Remediation
 Subtask 7.1: COMPLETE. Addressed plant remediation requirements.
  AEP John Amos U3 12/2010 DTE Belle River U2 12/2010

Task 8 – Install Zolo*BOSS*
 Subtask 8.1 – COMPLETE. Site Installation Plan
  AEP John Amos U3 < 11/2009 DTE Belle River U2 < 11/2009
 Subtask 8.2 – COMPLETE. Plant preparations
  AEP John Amos U3 3/2010 DTE Belle River U2 3/2010
 Subtask 8.3 – COMPLETE. Install Zolo*BOSS* combustion measuring equipment.
  AEP John Amos U3 3/2010 DTE Belle River U2 3/2010
 Subtask 8.4 – COMPLETE. Training
  AEP John Amos U3 4/2010 DTE Belle River U2 3/2010

Task 9 – NETL Phase 1 completion review
 Subtask 9.1 – COMPLETE. NETL Phase I Review - 4/13/2010.

Phase II – Plant Demonstration

Task 1 – Project Management
 Subtask 1.1 – COMPLTE. Reports were produced in compliance with Project Management Practices.
 Subtask 1.2 – COMPLTE. Reports detailing project progress was delivered monthly since the project inception.

Task 2 - Performance Engineer training

Subtask 2.1 – COMPLETE. Performance engineering training.

AEP John Amos U3 4/2010 DTE Belle River U2 3/2010

Task 3 – Plant Remediation

Subtask 3.1 – COMPLETE Addressed plant remediation requirements.

AEP John Amos U3 < 2/2010 DTE Belle River < 2/2010

Task 4 – Establish CO_2 CEM

Subtask 4.1 – COMPLETE. Validate CO_2 data precision and data recording in plant data historian.

AEP John Amos U3 < 2/2010 DTE Belle River < 2/2010

Task 5 – Complete Baseline test

Subtask 5.1 – COMPLETE. Baseline test performed to record plant CO_2 generation efficiency.

AEP John Amos U3 5/2010 DTE Belle River 5/2010

Task 7 – Zero order combustion tuning

Subtask 7.1 – COMPLETE. Manual tuning the combustion process

AEP John Amos U3 4/2010 DTE Belle River 5/2010

Task 8 – Zero order tuning baseline test

Subtask 8.1 – COMPLETE. Performance test after the manual tuning exercise

AEP John Amos U3 4/2010 DTE Belle River 5/2010

Task 9 – Combustion efficiency training for plant personnel

Subtask 9.1 – COMPLETE. Provide formal training on combustion efficiency for control room operators, I&C technicians, maintenance technicians and supervisors.

AEP John Amos U3 10/2010 DTE Belle River 4/2010

Task 10 – Install combustion optimization software

Subtask 10.1 – COMPLETE. Install computers and software as required.

AEP John Amos U3 10/2010 DTE Belle River 1/2010

Subtask 10.2 – PENDING Commission the software.

a) Belle River: COMPLETE. 8/2010
b) Amos: IN PROGRESS. SmartProcess optimizer is training on the combustion control of the Unit 3

Task 11 – Combustion optimization

Subtask 11.1 – IN PROGRESS. Combustion optimization efforts

a) Belle River: IN PROGRESS. Sustaining metrics are being monitored.
b) Amos: IN PROGRESS. SmartProcess optimizer is training on the combustion control of the Unit 3

Subtask 11.2 – IN PROGRESS. Plant testing repeated periodically as required during the optimization period.

a) Belle River: IN PROGRESS. Sustaining metrics are being monitored.
b) Amos: IN PROGRESS. Baseline and manual tuning tests complete. Further testing will occur after optimizer tuning if required.

Subtask 11.3 – IN PROGRESS Optimization will be measured on reduction in CO_2 emissions per MWh without degradation in other plant metrics.

a) Belle River: IN PROGRESS. Sustaining metrics are being monitored.
b) Amos: IN PROGRESS. Baseline and manual tuning tests complete. Further testing will occur after optimizer tuning if required.

Task 12 – Final report

Subtask 12.1 – COMPLETE. A written report will be generated with enough detail to replicate the results at other plants. 12/31/2010

References

[1] Nichols, C., Vaux, G., Zaremsky, C., Murphy, J., and Ramezan, M., (2008) "Reducing CO_2 Emissions by Improving the Efficiency of the Existing Coal-fired Power Plant Fleet", DOE/NETL-2008/1329, July 23, 2008.

[2] Conti, J.J., Holtberg, P.D., Beamon, J.A., Schaal , A.M., Sweetnam, G.E., and Kydes, A.S., (2009) "Annual Energy Outlook 2009 with Projections to 2030" DOE Report #:DOE/EIA-0383(2009) March 2009.

[3] Brindle, R., Eisenhauer, J., Greene, A., Justiniano, M., Kishter, L., Munderville, M., and Scheer, R., (2010) "Improving the Thermal Efficiency of Coal-Fired Power Plants in the United States Power Plant Optimization Industry Experience", Technical Workshop Report DOE/NETL, July 24-25, 2010

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[5] Tsou, J., (1998) "Heat Rate Improvement Reference Manual", EPRI TR-109546, July 1998

[6] Stallings, J., (2005) "Power Plant Optimization Industry Experience", EPRI TR-1011794 Technical Update, December 2005