The Case for Fuel Delivery System Upgrades on Utility Boilers

by

ASME Research Committee on Energy, Environment and Waste

The Fuel Delivery System Upgrades for Utility Boilers Subcommittee

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Abstract

Boilers 50 years and older comprise about 53 GW or 20% of the total U.S. fleet capacity and 40% of all coal-fired units. Most of these will be retired due either to normal business decisions or to mandated upgrades to the air pollution control systems. The next age group, the 30- to 45-year old units, comprises 216 GW and 63% of the total fleet capacity with an average unit capacity of 500 MW. These units will bear the burden of ensuring the usual high standards of electric grid performance, availability, and reliability. A vital part of any coal-fired unit is the Fuel Delivery System (FDS), comprising feeders, pulverizers, classifiers, coal piping and burners. A subcommittee of users, suppliers and architect/engineers under the ASME Research Committee on Energy, Environment, and Waste has investigated three typical 500-MW wall-, tangential-, and cyclone-, fired boilers originally designed for eastern bituminous coal and now firing low sulfur subbituminous Powder River Basin (PRB) coals. The subcommittee reviewed and selected retrofit upgrades to various parts of the FDS, determining costs, and the potential value of the ensuing benefits. The comparison of costs and benefits show surprisingly near-term breakevens of 15, 13, and 18 months, respectively, for the wall-, tangential-, and cyclone-fired boilers.

Introduction

This project was undertaken by the Fuels Delivery System Subcommittee of the ASME Research Committee on Energy, Environment, and Waste (RC EEW). After some 40 years of service the RC EEW has reinvented itself and expanded its horizons. Originally, as the Research Committee on Industrial and Municipal Waste, its focus was on waste and now it has expanded to all fuels, and the energy and environmental aspects of same. More information on the RC EEW is provided in Appendix 1 When forming the Subcommittee, it was important to have representation from the user, supplier and consultant communities. The subcommittee members indeed reflect that balance as shown in the Appendix 2.

In a recent article, “Predicting US Coal Plant Retirements,” by Bob Pelitier and Grant E. Grothen[1] it was shown that that the US coal-fired fleet consists of 1,105 units with a nameplate capacity of 342 GW. Many range in age from 85 to 20 years with only 35 plants having been added in the last 15 years. As a group, the units of 50 years and older comprise about 53 GW or 20% of the total fleet capacity and 40% of all coal-fired units. Many predict that many of these units will be retired due either to normal business decisions or to mandated upgrades to air quality control system (AQCS), imposed by MACT, on the basis that these upgrades will be cost prohibitive. Thus, the next age group, the 30- to 45-year old units, comprises 216 GW and 63% of the current coal fired generation fleet, which were built in the glory days of the 1960s as shown in Figure 1.

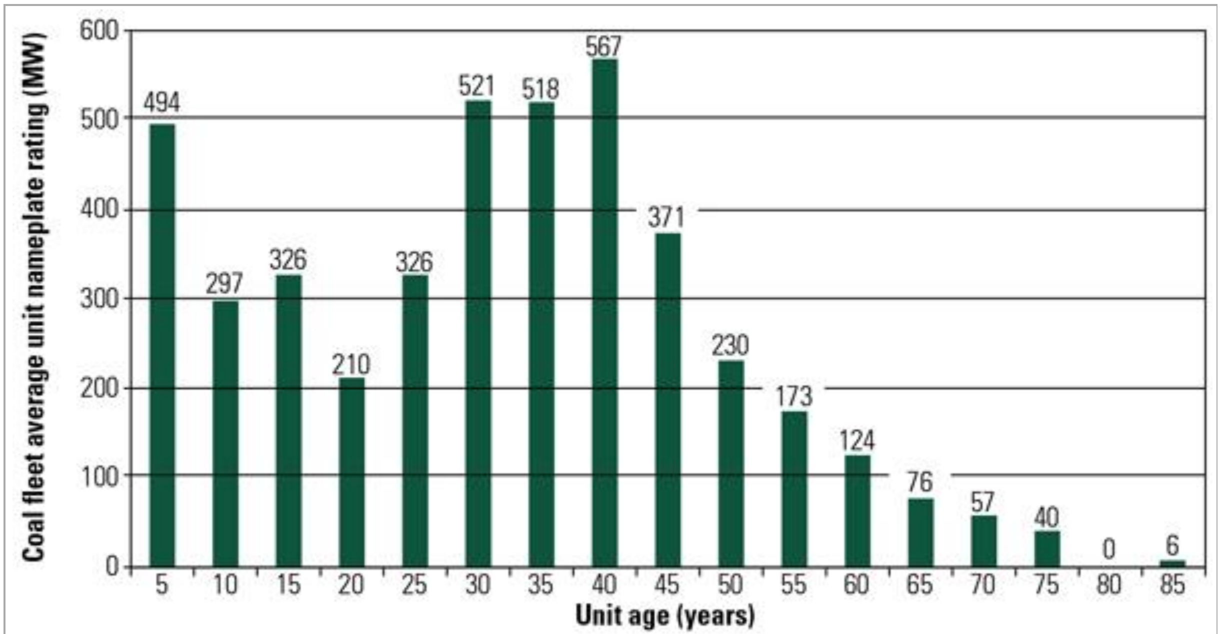

Figure 1. Coal fleet average unit nameplate rating. The average unit rating is calculated by averaging the rating all of the units within each age category. *Source: Ref 1 & POWER and Burns & McDonnell*

When the 50⁺-year old units are retired, the percentage is 75%. The 30- to 45-year old units are mainly opposed wall, cyclone, and tangentially-fired boilers with average capacity factors ranging from 61.8 to 73.3% as shown in Figure 2. These units – the backbone of the base loaded fleet - will bear the burden of ensuring the usual high standards of electrical grid performance, availability, and reliability. While most of these units have high grade AQCSs, they will require upgrades to comply with MACT, but the cost is not forecast to adversely impact unit competitiveness in terms of generation cost. However, the additional AQCSs required for environmental compliance will add to the pressure to maintain and/or increase the unit capacity factor.

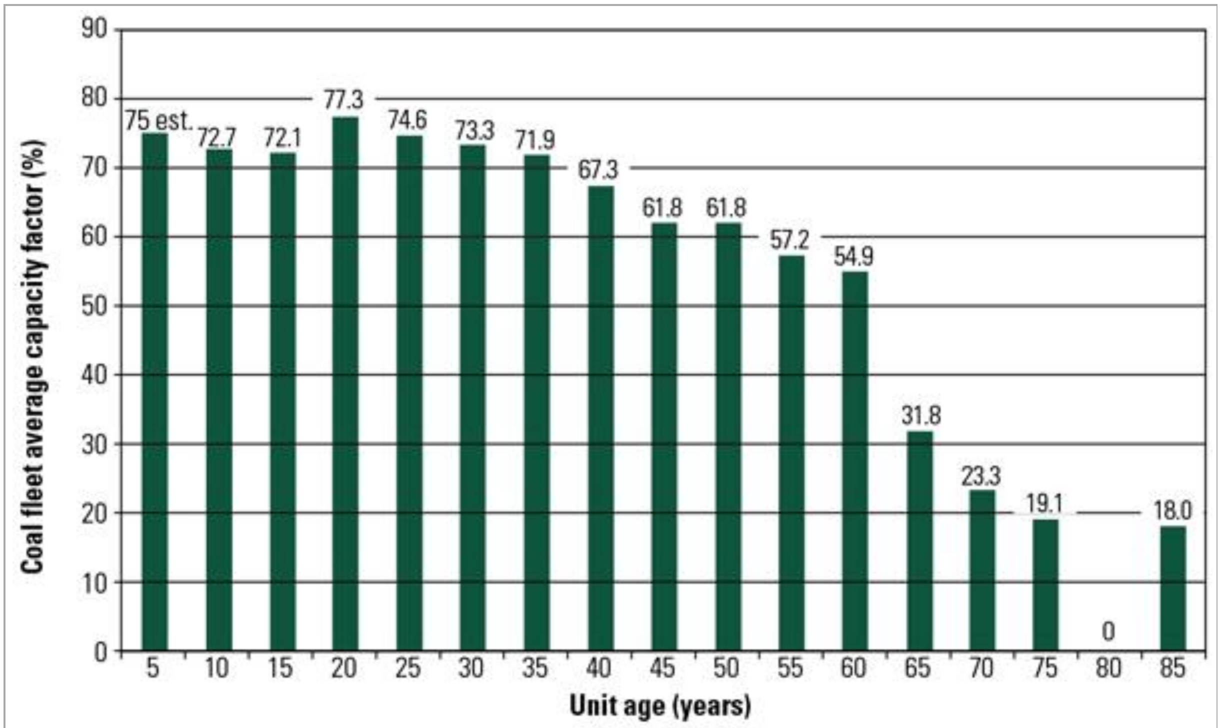

Figure 2. Coal fleet average Capacity Factor. The average unit capacity factor is calculated by averaging the reported capacity factor of all the units within each age category. Many of the units in the five years or less category do not have data available. A 75% capacity factor was estimated. In all categories, if capacity factor data was not available, that unit was omitted from the average. *Source: Ref 1 & POWER and Burns & McDonnell*

A vital part of any coal-fired unit is the Fuel Delivery System (FDS) as shown in Figure 3. This FDS, coined by John Welling, consists of the feeders, pulverizers (mills), classifiers, coal piping, and burners.[2] Such systems are vital for operation, much like a carburetor for an auto engine. Feeders, pulverizers and coal piping are high maintenance equipment due to wear from the coal.

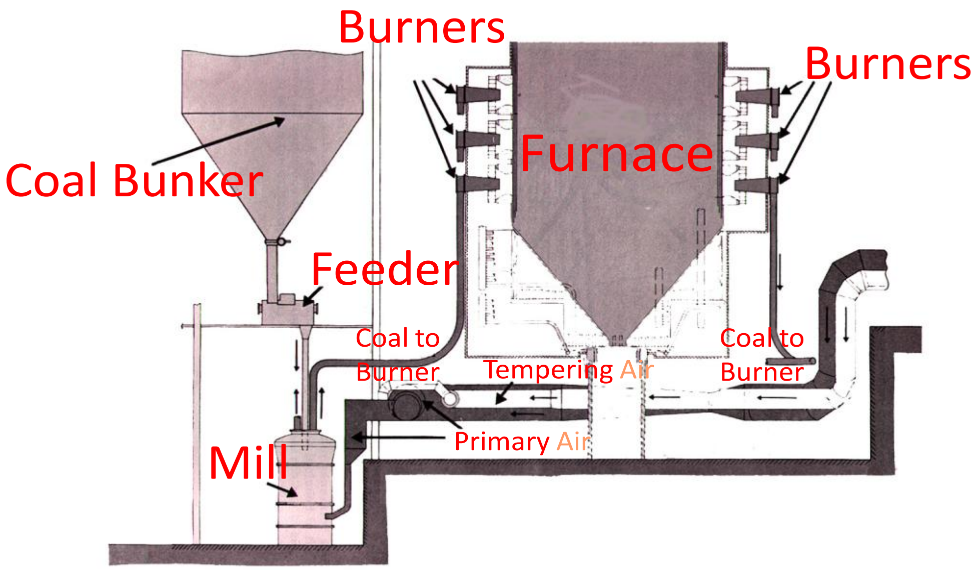

Figure 3. Fuel Delivery System

In recent years improvements in monitoring equipment have led to significant performance improvements in FDS equipment. Many of these have been in flow measuring devices for enhanced control:

- Feeder coal flow
- Pulverized coal flow in coal pipes
- Air flows
  - Total pulverizer preheated air
  - Coal pipe air
  - Total windbox air
  - Individual burner air (secondary and tertiary)

Thus, the amount of coal and air flows for all parts of the individual burners, so vital for Low NO_x Burner (LNB) operation, can be measured and monitored, assuring good combustion and minimized CO emissions. Please note that cyclone boilers utilize a different Fuel Delivery System comprising feeders, crushers, and cyclone burners that will be identified separately in the project economics.

Project

This project attempts to show that FDS upgrades can impact the availability, and reliability, as well as sustainability of a plant. Examples of potential upgrades for FDS components include:

Component	Upgrade	Benefit
Feeders	Metering	Flow control
Pulverizers	Dynamic Classifier	Fineness/Capacity
Coal Pipes	Coal-air flow metering	Flow and Air/Fuel Ratio
Burners	Metering	Improved combustion
Boiler Control System	Neural Networks	Improved performance

Each FDS component upgrade can have benefits, most of which can be quantified. An example is the retrofit of a Dynamic Classifier, which improves coal fineness and virtually eliminates the coarse coal particles (>50 mesh). Coarse particles are a main cause of fouling and deposition in the furnace and the convection sections of the boiler. They also impede good Low NO_x Burner performance. Improving fineness also reduces the unburned carbon in the fly ash, thus improving combustion and boiler efficiency.[3]

Methodology

It was decided that three boilers representative of the 35- to 50-yearold fleet would be selected - opposed wall, tangential-, and cyclone-fired boilers. It was also decided that these boilers would be real boilers, but that their identity would not be revealed, and the three would serve as case studies. In considering fuels, it was determined that most boilers in this age bracket had been originally designed for eastern or Illinois Basin coal and have been or are being considered for conversion to a subbituminous Powder River Basin (PRB) coal. Most boilers had had some burner modifications over their operational life and new modifications would be considered more for performance improvement considerations than for emissions reduction. In focusing on the FDS, it was further assumed that air pollution retrofits would not be part of the FDS upgrades. It was also assumed that any FDS upgrade would not increase the heat input over its original design rating, and that there would be no increase in emissions so as not to be a cause for New Source Review (NSR). In addition, the emissions would be less than 100 t/y for individual pollutants, thus not triggering PSD. It was assumed that the opposed wall and cyclone boilers had Selective Catalytic Reduction (SCR) systems installed for NO_x control, but that the tangential-fired unit did not yet require installation of an SCR due to the inherently low NO_x emission characteristics of the boiler design.

Naturally, there was considerable debate about these assumptions, and some were changed in the course of the Subcommittee's work. Traditionally, the 35- to 50-year old units have become workhorses of the fleet. The basic premise was to ensure that these units have higher reliability and higher availability, and also improved performance with the FDS upgrades. Thus, it was assumed that the capacity factor for this study would be 80 percent (7008 hours/year). In the current low natural gas price environment, this 80 percent capacity factor is likely higher than many units are currently operating. A sensitivity analysis was performed utilizing lower capacity factors. Higher capacity factors will likely return to the industry upon natural gas prices moving closer to the breakeven cost for gas-only wells, thus in the $4.50-5.50/10^6 Btu range.

Determining Upgrades and Benefits

For each case study the FDS Components were identified, and upgrades were proposed. Then the potential benefits of the upgrades were discussed and evaluated. Such sessions were always the source of interesting discussions with the collective expertise and experience of the subcommittee providing diverse inputs into each evaluation.

Determining Costs

Again for each case study the scope of the upgrade was defined in sufficient detail so that reliable estimated costs could be determined. Fortunately, the various suppliers and A/Es on the subcommittee were able to provide estimates of the installed costs for each upgrade considered based on prior experience.

Determining Savings

Certainly this was a central challenge in developing a complete cost assessment, and not everyone was convinced it could be done. The discussions were even more lively and spirited than the others, and were arrived at by consensus, not just at one session, but revisited several times. Sometimes it was decided that one component upgrade benefit could not be determined on its own, but rather only in combination with another. Such was the case where an evaluation of Neural Networks under the Boiler Control System provided a significant impact on boiler performance due mainly to a burner modernization, which on its own merits provided little in the way of savings.

Case Studies

It was felt that a clear and concise statement of the design, modifications, and current status of each case study 500-MW boiler was important. Yet it was to be representative of the boiler design class. The selection of the case studies was based in large measure by the coal fleet boiler design shown in Figure 4. In considering the ~500-MW units in the 35- to 45-year age range, the vertical and front-wall fired boiler were eliminated on the basis that few, if any, would be 500-MW boilers. Fluid bed units were also eliminated because few are larger units and most burn opportunity fuels. It was also felt that fluid bed units were so unique that they did not lend themselves to having a FDS. The same rationales applied to the Unknown category.

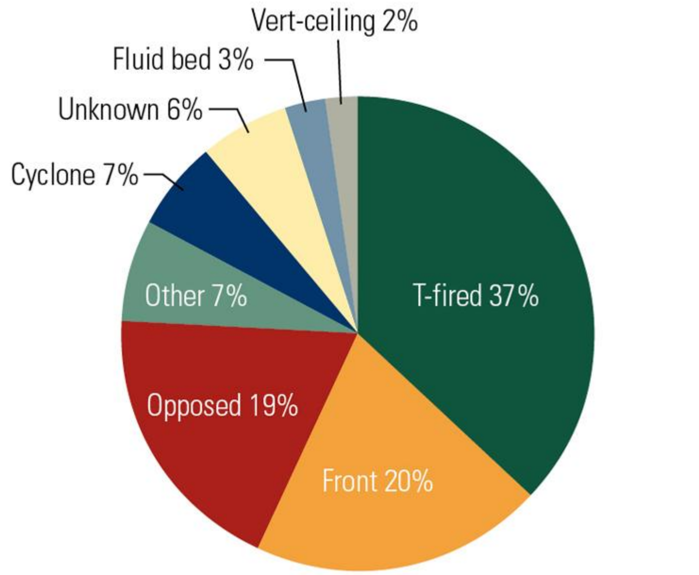

Figure 4. Coal fleet boiler design. *Source: Ref 1 & POWER and Burns & McDonnell*

Cyclone boilers provide an interesting opportunity for evaluation in this study. Cyclone boilers were essentially taken off the market in the 1980s when they were characterized as high NO_x emitters and not amenable to combustion modifications. Supposedly, they were also not amenable to PRB coal. In spite of such predictions there are upwards of 60 units still in operation, of which ten are in the 400 to 600 MW size range and four greater than 600 MW. Many of these have been converted to PRB coal and have had Overfire Air Ports installed for NO_x control. Thus, it was decided to keep them as a separate case study. However, the FDS boundary was expanded beyond the individual cyclone feeder to beyond the coal conveyors to the crusher-feeder island, usually located some distance from the boiler. It was felt that the crusher, more than any other device, controlled the particle sizing, and the upgraded feeder provided a more uniform flow of coal to the crusher improving overall crusher performance.

Case Study 1 – Opposed Wall Boiler

This opposed wall, natural circulation boiler was originally designed for eastern coal and now burns a western subbituminous PRB coal. It has a retrofit SCR and the original ESP with plans for a retrofit wet scrubber. The proposed FDS components for upgrade include:

- Replacement of original feeders
- Retrofit dynamic classifiers on vertical shaft pulverizers
- Coal pipe flow metering devices
- Burner modernization
- Retrofit ovefire air
- Air flow metering devices

- Retrofit boiler control system with a neural network
- Project management and engineering services

Feeders - The original ~40 year old feeders were volumetric and the new feeders are gravimetric with improved metering. They also provide some increased capacity since PRB, with its lower heating value, requires more material throughput than the original eastern bituminous coal. Six new feeders were estimated at 6 x $75k x 2 (Installation) = $900,000. Benefits were included with dynamic classifiers.

Pulverizers - Dynamic classifiers (DCs) are used primarily to increase coal fineness at a given coal throughput. In so doing DCs also reduce the coarse grind, the 50 mesh material, which is a primary cause of slagging and fouling. A lesser known feature of DCs is that they can also increase pulverizer capacity depending on DC speed; fineness at higher speed and throughput at lower speed. Typically this is accomplished with little or no increase in pressure drop.[3] Because PRB is a volatile coal, there is little need for an increase in coal fineness but there is a need for increased pulverizer throughput over the original Eastern coal design conditions. DCs costs were 6 x $300k x 2 (Installation) = $3,600,000 with the comment that $300,000 is on the high side and normal installation is usually less than 2x. With the previous switch from Eastern to PRB coal with its associated lower heating value the amount of coal passing through the FDS and the vertical shaft mills was limited so that the heat input to the boiler was reduced. Thus, the DCs enable the "recovery" of lost pulverizer and boiler capacity especially when one or more pulverizers are out of service for required maintenance work. A conservative value of five percent was used. The reduction of 50 mesh coal particles and improved combustion was estimated to result in recovery of two days of operation at full load. Other benefits included improved load response, improved coal drying, often less vibration, but modest NO_x and Unburned Carbon (UBC) reduction. The savings from the five percent capacity "recovery" was $8,760,000 and two days of full load operation at $0.05/kWh was $960,000, for a total savings of $9,720,000.

Coal Pipes - Coal Pipe flow meters were considered and benefits were acknowledged on the basis that flow measurement may still not be exact. However, coal flow can at least be compared on a relative basis to assure more equal and consistent coal flow to the burners to ensure good air to fuel ratios. There was some discussion about replacing coal pipes on the basis of increased pressure drop or fan limitation. It was felt that coal pipes are seldom replaced, and thus, sizing is never an issue. Upgrades required: Coal pipe flow - $500,000, and Primary air flow - $200,000 for a total of $700,000. One has to accurately measure both coal and air to gain a potential for an aggressive efficiency improvement. It was also felt that the DCs would resolve a potential pressure drop issue, and pressure drop issue was further clarified as shown below in Boiler Control System

Burner Modernization - The present Low NO_x Burners (LNBs) are a third generation and a fourth generation is the planned burner modernization to include air flow monitoring devices. Overfire Air is also included. NO_x reduction with these new LNBs and OFA would be about 10 percent (~0.02 lb/10^6 Btu) but serve primarily to reduce NH_3 consumption. UBC would not be decreased, and CO would be held to <100 ppm.

The combination of retrofit DCs and LNBs would reduce slagging and fouling, improve flue gas flow to the SCR and air heater, provide better combustion and improve boiler performance. Typically, LNBs are upgraded every 6 to 8 years due to improvements. Costs were estimated as - LNBs $75k x 24 burners x 2 (Installation) = $3,600,000; OFA $25,000 x 8 + $50,000 x 8 (Installation) = $600,000; Electrical $1,000,000 (Installation); and $200,000 for Burner Management (new scanners, cabinets, etc.) for a grand total of $5,400,000. The only direct benefit was some NO_x reduction which reduced annual NH_3 usage by $210,000. The other benefits for improved combustion were improved boiler performance, which is shown in the Boiler Control System Savings.

Boiler Control System - In a detailed analysis by a Burns and McDonnell team, all the various upgrades were examined and critiqued with a review and modification of the cost when merited. In the original consideration of upgrades to Boiler Control System (BCS) it was felt a new BCS would provide benefits as well as a Neural Net system. As it turned out, the BMcD team revised the BCS upgrade to only a Neural Network. This applied to pulverized coal fired boilers (Case Studies 1 and 2) and provided unexpected benefits.

Two good rules of thumb is “10 percent Excess Air = 0.5 percent Boiler Efficiency” and “10 percent Excess Air = 22 percent Fan Power”. Using these rules of thumb, difference is (22.8%-16.1%) 6.7 percent change in Excess Air which results in approximately 0.34 percent improvement in Boiler Efficiency and 15 percent improvement in fan power. 500 MW x $0.05/kWh x 7008h/y x 0.0034 = approx. $600,000/y savings for Boiler Efficiency. Assuming 2 x 4,000 HP fans, 8,000HP x 0.7457kW/HP x $0.05/kWh x 7008h/y x 0.15 = approx. $314,000/y savings in fan power. Improving NO_x from 0.17 lb $NO_x/10^6$ Btu to 0.15 lb $NO_x/10^6$ Btu – (Assume 10,500 Btu/kWh, $400/ton Anhydrous Ammonia, SCR outlet NO_x 0.04 lb/NOx/10^6 Btu at 80 percent C.F.) Reagent (Anhydrous Ammonia) savings – $85,000/y, for a total savings of $999,000.

Boiler Cleaning - One Subcommittee member suggested that there is a need for boiler cleaning upgrades for PRB coal to address both the furnace reflective ash and fouling of convective sections, both of which negatively impact heat transfer. Such an upgrade would include Furnace Exit Gas Temperature monitoring instrumentation and some additional wall and convective pass cleaning equipment and/or improved controls. While a worthwhile consideration, the instrumentation and boiler cleaning hardware are downstream of the FDS, and thus not considered to be part of the FDS.

Project Management & Engineering Services - An unanticipated cost was project management and engineering services. Once it became clear that there were several upgrades and they were somewhat complicated to install, the Architect/Engineer (A/E) colleagues on the Subcommittee successfully argued that project management would be necessary for successful upgrade installation and integration. Such PM services were estimated to be ten percent of the upgrade costs and engineering services including commissioning costs, to be about 15 percent plus an additional 10 percent for Project Management costs for total of 25 percent, which amounted to $2,725,000.

Thus, the total costs were $13,625,000 and the total savings were $10,925,000 and the Breakeven is 15 months, as shown in Table 1. It is worthy to note that 83% of the savings stem from the recovery of a presumed 5 percent unit derate when the unit was converted from eastern bituminous coal to a western subbituminous PRB coal.

Table 1 - FDS Upgrade Benefits and Costs for Case Study 1- Opposed Wall Boiler

Component	Upgrade	Cost, $k	Savings, $k/y
Feeder	New Feeders	900	Combine with DCs
Pulverizer	Dynamic Classifiers	3,600	5% "Recovery" 8,760 2 Days Operation 960 Subtotal 9,720
Coal Pipes	Coal-air flow	700	Combine with BCS
Burner Modernization	LNBs & OFA	5,400	Some NOx reduction as NH3 savings but other benefits claimed in BCS: NH_3 210
Boiler Control System	Neural Network	300 Subtotal 10,900	Efficiency 596 Fan 314 NH_3 85 Subtotal 995
Proj Mgt & Engr Services	25%	2,725	
Total		13,625	10,925

Breakeven 15 months

Case Study 2 – Tangential Fired Boiler

A 500-MW tangential-fired boiler would be a single furnace, and not a divided or twin furnace. It has 5 levels of burners and 5 pulverizers, 100 MW per pulverizer. Many in this size and age do not have SCRs. In many ways tangentially fired boilers are similar to opposed fired boilers, but they typically have lower NO_x and UBC. The consensus was that burner mods would be appropriate regardless of whether or not a SCR was added. Instead of concentrating the fire ball, the burner levels are now separated, and thus further reducing NO_x emissions. The benefits of DCs with regard to recovery of lost capacity apply, but the need to improve slagging and fouling may not be as great. Burner mods would involve changing buckets and Separate Overfire Air (SOFA). NO_x reduction may be less but the NO_x emissions are likely to be low. Neural Networks would provide similar improvements

Feeders – As with Case Study 1 the original ~40 year old feeders were volumetric and the new feeders are gravimetric with improved metering. They also provide some increased capacity since PRB, with its lower heating value, requires more material throughput than the original Eastern coal. Five new feeders were estimated at 5 x $75k x 2 (Installation) = $750,000. Benefits were included with DCs

Pulverizers – Dynamic classifiers (DCs) are used not so much to reduce fineness but to eliminate the 50 mesh material, which is the cause for slagging and fouling. DCs costs were 5 x $300k x 2 (Installation) = $3,000,000 The reduction of 50 mesh coal particles and improved combustion was estimated to result in recovery of two day of operation at full load. Other benefits included improved load response, improved coal drying, often less vibration, but modest NO_x and Unburned Carbon (UBC) reduction. The savings from the 5 percent capacity "recovery" was $8,760,000 and two of full load was $600,000, for a total savings of $9,368,000.

Coal Pipes – As in Case Study 1, unit upgrades chosen were coal pipe flow and primary air flow measurement at a total of $584,000.

Burner Modernization – The modernization comprise some bucket replacement and the addition of Separate Overfire Air ports, which would require some boiler pressure part modifications. SOFA was estimated at $6,000,000. Benefits were some NO_x and UBC reductions claimed but no significant savings were estimated.

Boiler Control System - The same upgrade of a Neural Network with no new BCS costs $300,000 with the similar savings forecast as delineated in Case Study 1 for reduction in excess air operation – boiler efficiency $600,000 and fan reduced power costs $314,000 – albeit there is no savings for NH_3 because the is no SCR. Thus, the estimated savings were $914,000.

Project Management & Engineering Services – PM&ES services were estimated to be 25 percent of the upgrade costs, which amounted to $2,359,000.

Thus, the total costs were $11,793,000 and the total savings were $10,282,000, and the Breakeven is approximately 13 months, as shown in Table 3. As before, 82 percent of the savings are attributable to recapturing 5 percent of the unit capacity incurred with the initial fuel switch from an eastern bituminous coal to a lower heat content subbituminous PRB coal.

Table 2 – FDS Upgrade Benefits and Costs for

Case Study 2 – Tangential-Fired Boiler

Component	Upgrade	Cost, $k	Savings, $k/y
Feeder	New Feeders	750	Combine with DCs
Pulverizer	Dynamic Classifiers	3,000	5% "Recovery" 8,760 2 Days Operation 960 Subtotal 9,720
Coal Pipes	Coal-air flow	584	Combine with Boiler Control System
Burner Modernization	New Burners SOFA, pressure part mods, ducts, & dampers	4,800	Some NO_x and UBC but no significant savings 0
Boiler Control System	Neural Network	300 Subtotal 9,434	Efficiency 596 Fan 314 Subtotal 914
Proj Mgt & Engr Services	25%	2,359	
Total		11,793	10,630

Breakeven 13 Months

Case Study 3 – Cyclone Boiler

The cyclone boiler investigated for this case study was originally designed to fire Illinois Basin bituminous coal (late 1960s), but now burns PRB coal (late 1980s), and has retrofit Overfire Air (1990's), SCR, Dry Flue Gas Scrubber, Fabric Filter, ID fans (converted from pressurized to balanced draft), various boiler and turbine mods, and new O_2 analyzers (2000's). FDS upgrades that were considered included):

- Twelve cyclone sectionalized secondary air damper upgrades,
- Air flow monitors for individual cyclone sectionalized air flow measurement
- Feeder-Coal crusher upgrades and additions

The Feeder - Crusher "Island" was included in the FDS boundary since this equipment is such a vital part of coal sizing for good combustion. It was generally agreed that some modification would have been made to the Feeder-Crusher Island when switching to PRB coal, which would have included dust control and other safety related issues. The same would have been included in all the coal conveyors, but the coal conveyors from the Feeder-Crusher Island to the Cyclone are not part of the FDS. As part of the FDS upgrade some upgrades will be made to the Feeder-Crusher Island to improve coal grind at a given or increased throughput and these costs were estimated. In discussing the Cyclone Modification, it was agreed that the twelve Cyclones Feeders and Burners would have had some modifications previously, but that the upgrades considered now as part of this program would include upgrades to reduce UBC (Loss on Ignition), which in some cases is 20 to 30 percent. .

Feeder-Crusher Island – Upgrades include a new posimetric feeder, fine grind cage crusher and motor upgrades at $1,200,000.

Cyclone Modernization – Cyclone were upgraded with new Split Secondary Air Dampers and Damper Actuators. Benefits include reduced NO_x and UBC by improving combustion allowing low excess air operation, more even flue gas distribution in the furnace convection sections, SCR, and air heater as well as reduced slagging. The upgrades were estimated at $2,800,000. The benefits were reduced operation at lower loads with individual cyclones forced out of service due to cyclone slag buildups and also downtime for boiler deslagging. Longer time is usually required to cool cyclone furnaces for deslagging and maintenance work. Thus, the savings was based on the unit being available for an additional seven full days of operation in a year by reducing forced outages for cyclone cleaning, and was calculated at $3,360,000. It was discussed that if the cyclones themselves were nearing the end of their usefully life and planned to be replaced, there are numerous upgrades that should be incorporated in the replacement cyclones to further enhance PRB coal firing, but as it was felt that if the cyclones were not to be replaced, these pressure part upgrades would not be made just to improve PRB coal firing. For this reason the costs of new cyclones or cyclone pressure part upgrades was not addressed by this study.

Boiler Control System – Only an upgrade to the BCS was required. Thus no new BCS and no Neural Network was provided. This upgrade provided a savings similar to that shown for Case Study 1 except there was no significant NH_3 savings: Efficiency $298,000, Fan $157,000 for a total of $455,000

Project Management & Engineering Services- PM & ES were estimated to be 25 percent of the upgrade costs, which amounted to $1,120,000.

It was pointed out that the OFA installed during the PRB conversion was designed to meet a modest NO_x limit with the likelihood that more stringent NO_x regulations would result in a retrofit SCR, which had been installed. Another reason for not deep staging was that it caused problems with slag flow. Since then, the use of iron oxide additives has shown that slag chemistry is changed allowing for improved slag flow under deeper staging. While this would reduce NO_x further and provide savings in NH_3 usage, the use of additives (Refined Coal) was not considered to be part of the FDS, and no costs or savings were determined for same.

Thus, the total costs were $5,600,000 and the total savings were $3,815,000, and the Breakeven is 18 months, as shown in Table 2. Here again, it should be noted that 88 percent of the cost savings are attributable to potential recovery of lost generation due to derates or forced outages due to convective pass slagging.

Table 3 - FDS Upgrade Benefits and Costs for Case Study 3 - Cyclone Boiler

Component	Upgrade	Cost, $k	Savings, $k/y
Feeder/Crusher "Island"	New Feeders & Instrumentation	1,200	Combine with Cyclone Modernization
Cyclone Modernization	Cyclone upgrades and new "Split" air damper	2,880	7 days full load operation due to elimination downtime caused by slagging 7 days 3,360
Boiler Control System	Update Boiler Control System	400 Subtotal 4,480	Efficiency 298 Fan 57 Subtotal 455
Proj Mgt & Engr Services	25%	1,120	
Total		5,600	3,815

Breakeven 18 months

Breakevens – The Costs and Savings along with the Breakevens are summarized in Table 4.

Table 4 - Summary of Case Study Costs, Saving, and Breakevens

Case Study	Type	Cost, $k	Savings, $k/y	Breakeven, Months
1	Opposed Wall	13,625	10,925	15
2	Tangential	11,973	10,630	13
3	Cyclone	5,600	3,815	18

The above is based on a Capacity Factor of 80 percent which was the basic premise of the study where the proposed FDS upgrades were selected to increase reliability and availability, and also improve boiler performance. Since this study began, the market has changed somewhat. Some coal-fired boilers have been used less, because gas-fired units have been used in lieu of coal-fired units, or where applicable, natural gas has been fired in coal-fired boilers. In order to evaluate the impacts of lower Capacity Factors, potential savings were calculated at 60 and 70 percent, assuming the upgrade costs would remain the same, as shown in Table 5.

Table 5 - Impact of Capacity Factor on Savings and Breakeven

Capacity Factor, %			60	70	80
Case Study	Boiler Type				
1	Opposed Wall	Savings, $k	8,295	9,096	10,925
		Breakeven, Months	20	18	15
2	Tangential	Savings, $k	7,973	9,301	10,630
		Breakeven, Months	18	15	13
3	Cyclone	Savings, $k	2,861	3.331	3,815
		Breakeven, Months	23	20	18

As would be expected, the savings decrease, but the breakevens for all the Case Studies are less than 2 years

Redoing Case Studies for Eastern Coal

Initially Eastern coal was to be considered after PRB coal on the basis that many units were installing wet scrubbers so that high sulfur Eastern coal may become more economical. Presently production and transportation costs for Eastern coal has increased so that few utilities are considering conversion back to Eastern coals.

Market Size

A supplier would naturally ask how many units are the in the 30- to 45-year old group. Rough estimates indicate over 220 opposed wall, over 140 tangentially-fired, and about 15 cyclone fired boilers.

Conclusions

Most the Subcommittee members were surprised at the relatively short breakevens or short project payback periods. The costs and savings were revisited and largely remained unchanged. Clearly the Dynamic Classifier and Neural Net upgrades provided some amazing projected savings at the 80 percent capacity factor, and acceptable savings at lower capacity factors.

As stated previously the assumed Capacity Factor was 80 percent, and the costs and savings will change at lower Capacity Factors, which can be driven by electricity demand.

Next Steps

The next step is just what is being done with this paper and presentation – getting the word out, and soliciting feedback.

As EPA prepares regulations for the control of carbon dioxide (CO_2) emissions, the Subcommittee is planning to consider redirecting its efforts to ways to reduce CO_2. For the opposed and tangentially fired boilers (Case Studies 1 and 2) an improvement of 0.34% improvement in boiler efficiency resulted in a reduction of 6.5 lb CO_2 /MWh or 1,380 t CO_2 /y. Cyclone units (Case Study 3) were about half of pulverized coal units. The Subcommittee will investigate other potential way of reducing CO_2 Emissions not only for the 30 – 45 year old units but also the 0-25 year old units.

Footnote

This Subcommittee came about as part of a renaissance of the RC EEW. The journey over the past 20 months in monthly one-hour conference calls has been an amazing adventure. The Subcommittee is to be commended for its efforts. As its Chair, it was an honor and pleasure to work with them.

References

1. R. Peltier and G. E. Grothen, “Predicting U.S. Coal Plant Retirements,” POWER, May 2011, pp.56-64

2. J. C. Welling, J. Kinter, and R. E. Sommerlad, "The Benefits of Dynamic Classification and Fuel Line Balancing for Improving Boiler Performance," presented at the International Joint Power Conference & Exposition, Phoenix, AZ, October 3-5, 1994.

3. R. E. Sommerlad and K. Dugdale, “Dynamic Classifiers Improve Pulverizer Performance and More,” POWER, July, 2007, pp. 52-55.

Appendix 1

An Overview of the ASME Research Committee on

Energy, Environment and Waste

The Research Committee on Energy, Environment and Waste (RC EEW) had its beginnings in the late 1960s as the Research Committee on Industrial Waste, focusing on industrial waste. In the 1970s it expanded to include Municipal Solid Waste, and in the 1980s Hazardous Waste and Medical Waste. In the past the RC EEW explored research needs in industrial, municipal, reference method accuracy and precision, solid waste; municipal solid waste disposal; medical waste; hazardous waste incineration, monitoring and control, waste treatment systems; waste management, landfills, recycling, guidelines, regulations, solid residue (ash), vitrification, combustion, municipal solid waste, emissions, incinerator sources, metal emissions, incineration, and other technologies relating to waste materials.

The RC EEW also interfaces with other organizations that deal with design, operations, research and regulations concerning industrial, medical and municipal waste management. These include DOE and DOD in its remediation sites, and EPA in the field of productive use of industrial wastes as energy and material resources, as well as in advance review of new or revised regulations.

At the turn of the century it again expanded to include energy, and other environmental issues. In recent years its activities waned, but two years ago it had a renaissance. Two new subcommittees have been formed. The Fuel Delivery System Upgrades for Utility Boilers Subcommittee deals with coal-fired boilers and the fuel delivery system, namely the equipment from the feeders to the pulverized burners. Since its formation in November, 2011, it has also made significant progress culminating in presentations at two upcoming technical conferences. The Erosion and Corrosion Subcommittee will deal with boiler tube wastage in boilers and erosion and corrosion in air pollution control equipment.

Appendix 2

Roster of the Fuel Delivery Systems Upgrade Subcommittee

Affiliation	Group
Robert Chase, Terrasource Global	Supplier
Blaz Jurko, Gebr. Pfeiffer, Inc.	Supplier
David J. Stopek, Consultant, Sargent & Lundy LLC	Consultant
Grant E. Grothen, Principal, Burns & McDonnell	Consultant
Steven McCaffrey, President, Greenbank Energy Solutions, Inc.	Supplier
Melanie Green, Director, CPS Energy	User
Don B. Pearson, The Babcock & Wilcox Company (Retired)	Supplier
Richard Himes, EPRI	User
Tony Licata, Licata Engineering Consulting (Retired -Babcock Power) & Chair RC EEW	Supplier
Robert E. Sommerlad, Consultant & Chair, FDS Subcommittee	Consultant
Todd Melick, Vice President, Promecon USA	Supplier
Joe Von der Haar, Plant Manager, East Kentucky Power	User