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TECHNICAL PUBLICATION

OPERATING EXPERIENCE AND FUTURE CHALLENGES WITH SCR INSTALLATIONS

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ABSTRACT

The installation and operation of Selective Catalytic Reduction (SCR) systems in the U.S. have benefited greatly from the experience gained by European SCR installations. The installation and operating experience from select European SCR installations are reviewed. The paper also discusses the installation and operating experience of two U.S. SCR systems, Public Service of New Hampshire (PSNH) Merrimack Station Unit 1 and Pennsylvania Power & Light Company's (PP&L) Montour Steam Electric Station Unit 2. Unfortunately, the experience gained from European installations is not sufficient for all designs required in the U.S. due to differences in fuels, design requirements and operating conditions. These differences and their associated challenge for the SCR designer are also discussed.

INTRODUCTION

The Selective Catalytic Reduction (SCR) Systems currently being designed for U.S. installations have benefited greatly from an examination of the European SCR installations (see Table 1). The importation and preservation of the German SCR core technology into the U.S. market with the simultaneous adaptation of this technology to new fuels, design requirements of higher efficiencies with lower outlet emission rates, and operating conditions requiring regular seven-month non-OTAG season layup are some of the challenges that the designers of SCR systems in the U.S. currently face. The German SCR technology holds forth the best experience base of long term performance of SCR systems on coal fired boilers and is the platform upon which the U.S. market is building.

In the past there has been a very meaningful exchange of information between the U.S. and Europe, the best recent example being the technology for Wet Flue Gas Desulfurization (WFGD) Systems. Recall that the original U.S. Clean Air Act of 1970 stimulated the development of the limestone WFGD system that was then exported to Germany for use in response to their regulations. The German regulations of the 1980's encouraged the further development of the U.S. type WFGD system to include generation of a gypsum by-product.

In turn the 1990 U.S. Clean Air Act Amendments for SO2 control were largely met by the reimportation of the German type WFGD systems back to the U.S. with considerable success. Overall, the applications of these systems in the U.S. cost less than the original projections and are performing very well.

Table 1 Technical Data of Selected U.S. and European SCR Plants

Plant	PSNH Merrimack Unit 1	PP&L Montour Unit 2	BEWAG KW Reuter Units D&E	Altbach HKW Neckar Unit 1
Capacity MW_{el}	122	745	300	460
Boiler Type	Bituminous coal	Bituminous coal	Bituminous coal	Bituminous coal
Flue gas volume m^3/h STP SCFM	312,750 217,500	2,606,300 1,646,300	930,000 580,000	1,300,000 821,200
Inlet NO_X as NO_2 at reference O_2 mg/m^3 STP dry lbs./10^6Btu	2018 1.34	600 0.4	650 0.52	650 0.52
Outlet NO_X as NO_2 mg/m^3 STP dry lbs./10^6Btu	<226 <0.15	<60 <0.04	<150 <0.12	<200 <0.16
Design NOx reduction %	88.9	90	77	81.5
Design temperature °F	660	725	725	698
Design NH_3 slip ppm(v)	< 5	< 2	< 5	< 5
No. of SCR reactors	1	2	1	1
Year of commissioning	1999	2000	1988/1989	1985/1990
SCR installation	High dust retrofit	High dust retrofit	High dust retrofit	High dust retrofit
No. of catalyst layers	3 + 1 spare	2 + 2 spare	3 + 1 spare	3
Type of catalyst pitch mm	Plate 5.4	Honeycomb 7.1	Honeycomb 7.4	Honeycomb 7.4
Sootblowers	On all layers	On all layers.	On first layer.	-

We are currently successfully repeating this process of technology importation for SCR systems. Once again, as with WFGD systems, the market place is requiring a significant cost reduction while the core technology is preserved to ensure long-term performance already demonstrated in Europe. This process is very successful when the European experience is directly transferable to the U.S. market with primary design parameters falling within the experience range of European installations. However, when the primary design parameters fall outside the known experience range, the SCR designer must rely on experimentation and analysis methods proven both in Europe and the U.S. to provide insight to the new challenges.

The German SCR installations on coal-fired boilers total about 33,000 MW, equal to about 70% of the world's SCR coal-fired experience base. The Babcock Borsig Power group (BBP) combines the experience of Deutsche Babcock, Steinmüller, and Noell KRC collected into a single operating group. This combination of experience has put the first SCR installations downstream of coal-fired boilers in Germany into service beginning as early as 1985. The BBP group has also equipped 15,000 MW of boiler capacity with SCR systems in both high-dust or tail end configurations.

SCR SYSTEM DESIGN CONFIGURATIONS AND CONSIDERATIONS

In general, there have been three basic SCR system configurations: high dust with the SCR between the economizer and air preheater, low dust with the SCR after precipitator, and tail end with the SCR after the WFGD. In the U.S., the high dust configuration with the SCR reactor installed between the economizer and air preheater is currently dominating the market.

High dust configurations, downstream of the economizer, require that the SCR process inlet temperature be maintained below a minimum to prevent the capillary condensation of ammonium sulfate $(NH_4)_2SO_4$ and ammonium hydrogen sulfate NH_4HSO_4 in the catalyst. These sulfates condense in the pores of the catalyst and result in catalyst deactivation. The condensation process can be reversed by operating the SCR at temperatures above 660°F (350°C), for a period of time after the catalyst has been operated below the minimum temperature. The original catalyst activity can be almost fully restored if such procedures are followed. Some high dust installations require an economizer by-pass to achieve the required minimum operating temperatures at low loads of the boiler. The design of high dust economizer bypass systems in general have four basis configurations: flue gas bypass around the economizer, water side bypass around the economizer, relocation of the economizer behind the SCR reactor, and increased economizer inlet water temperature. The fourth economizer type, increased economizer inlet water temperature, is only an option on supercritical installations. BBP has had good success with all of the above methods of SCR inlet flue gas temperature control in Europe and has applied or studied all methods in the U.S. market. Depending on the design fuel range for the boiler, the design of the catalyst has to be selected accordingly considering dust burden and catalyst poison concentration in the flue gas.

The tail end arrangement in power stations is mainly employed for retrofits if a high dust arrangement cannot be implemented for layout reasons, or if the concentration of catalyst poisons in flue gas are unacceptability high. The disadvantage of this arrangement is the need to reheat the flue gases to the reaction temperature of approximately 570°F (300°C) at the inlet of the SCR reactor. The concentration of the SO_3 remaining in the flue gas after desulfurization and the proportion converted in the catalyst dictate this inlet minimum operating temperature requirement. This minimum temperature is same as that required in the high dust configuration described above. The flue gas that has been cooled down in the desulfurization plant to its saturation temperature now must be heated up either by passing it over a steam coil type heat exchanger system or through direct heating with induct burner systems. Using the above methods, the heat required to increase the flue gas temperature for acceptable heat transfer areas in the gas-gas heat exchanger comes from either high-pressure steam or natural gas and fuel oil. This heating capacity corresponds to approximately 3% of the unit output, so that the efficiency of the power station is correspondingly lowered. The gas-gas heat exchanger minimizes the heating required and lowers the stack gas temperature to acceptable levels with a regenerative heat exchanger following the Ljungstrom principle. Since the regenerative heat exchanger system will have leakage between the inlet raw gas and the outlet clean gas, it requires that increased reactor removal efficiencies be obtained to achieve the same overall SCR system removal efficiency. The decision of whether the tail end system is economical requires a case-by-case evaluation.

The main advantage of this arrangement is the considerably smaller loss of activity over the working life compared to the high dust catalysts, because many catalytic poisons such as arsenic, alkali metals, and alkaline earth metals are removed in the upstream flue gas cleaning stages.

The low dust configuration is identical to the tail end with the exception that the SCR is installed before the desulfurization plant (if one exists). This configuration has not proven to be economically effective since it requires the additional capital equipment and operating costs of the tail end configuration without the benefit of reduced inlet SO_2 rates and reduced inlet ash concentrations typical downstream of a WFGD. The BBP group has experience with both the high dust SCR and tail end SCR system configurations. The primary focus of this paper is the high dust SCR systems installed immediately after the economizer, currently the most popular configuration in the U.S. market.

BEWAG KW REUTER UNITS D AND E

The KW Reuter Project is a retrofitted SCR System to each of two 300 MW pulverized bituminous coal-fired boilers. The SCR Systems started up in November 1988 and January 1989 respectively. The SCR reactors are top-supported and located immediately after the economizer. Anhydrous ammonia is injected through a multi-nozzle grid and the catalyst is honeycomb type with a 7.5 mm pitch. (This pitch dimension is roughly the length of one side of the square opening through which the gas flows.) The inlet NO_x is about 650 mg/Nm^3 (0.52 lb/10^6 Btu) and the reduction is 77% to 150 mg/Nm^3 (0.12 lb/10^6 Btu). The end-of-life ammonia slip guarantee was 5 ppm at 20,000 hours. The flyash loading is fairly typical at 11,700 mg/Nm^3 (about 6 gr/dscf).

This project was designed, constructed, and successfully put into operation in 1988/1989. Unfortunately, the ductwork configuration contained a relatively short horizontal run where during prolonged low load boiler operation the gas velocity was insufficient to keep all the flyash in suspension. This resulted in some of the flyash settling out on the floor of the horizontal duct. It is believed that when there is a rapid increase in load from low to high, the flyash traveled as a moving dune and flowed at very high concentrations into the reactor. This high flyash loading overwhelmed the catalyst to the point that the flyash accumulated on a section of the uppermost surface of the catalyst face and greatly restricted gas flow. The pressure loss became excessive and load was curtailed to unacceptably low levels. The solution was the installation of ash hoppers immediately upstream of the reactor entrance. This configuration diverted the ash flow from the reactor and catalyst face and allowed satisfactory operation. The SCR designer must fully understand the ash characteristics and loading under normal full-load operation, part-load operation, when sootblowing, or when excursions occur.

BBP has found the best solution of this problem to be a total ductwork system design approach. This design approach utilizes the known characteristics of the ash, ash samples if available, and the normal and unusual operating conditions. Using the proposed ductwork and reactor configurations, a scale three-dimensional flow model is constructed that can, through empirical evaluation, detect and control flyash accumulations both in the ductwork and on the face of the catalyst. The ductwork arrangement is then finalized incorporating the knowledge gained from the flow model. In extreme cases hoppers may be the best solution, but often they can be avoided through optimizing the ductwork configuration. This achieves overall system cost reduction and simplified system operations.

At KW Reuter, after a few years of operation, the owner had experienced problems with low boiler exit temperature operation. Operation below a minimum temperature can cause ammonia salts to deposit on the catalyst surface. The owner elected to retrofit an economizer by-pass to keep the gas temperature higher at low loads. The retrofitted economizer bypass introduced two new problems; a non-uniform NO_x concentration profile in the flue gas and a flue gas velocity maldistribution. Attempts were made to improve performance, adjusting the ammonia injection flow among the 130 nozzles that make up the ammonia injection grid. These adjustments proved unsuccessful and three years after initial start-up both Unit D and E were retrofitted with Delta Wing™ static mixing devices. The installation of these static mixing devices resolved the maldistribution problems at the inlet catalyst face.

ALTBACH HKW NECKAR UNIT 1

The 460 MW steam generator in Altbach was retrofitted with an SCR plant in 1989/1990. Since little space was available in the almost completed boiler house, the SCR reactor was designed to treat 80% of the boilers flue gas flow rate. An increased removal efficiency of 87.5% allowed compliance with the boundary value of < 0.16 lb/10^6 Btu (200 mg/m^3 STP dry) for the entire flue gas flow entering the stack. The plant was modified to a 100% full-flow plant in 1990 when one of the two bypass ducts were enlarged as an additional reactor and loaded with catalyst. The reagent used on the project is anhydrous ammonia with a vaporizer and a grid injection/mixing system. The plant has been in operation for over 90,000 hours and, for the most part, fires domestic Ruhr and Saar coal with an ash content of 6-8%. The reactor was planned without sootblowers to clean the catalysts. Although, flow conditions were not optimal due to the need to integrate the plant into the completed boiler house with little space available, no significant catalyst fouling has occurred without sootblowing. The plant uses all three available catalyst planes as well as a former flow rectifier, which has now been charged with catalyst. Originally a honeycomb catalyst with 7.4 mm pitch was employed. Meanwhile a pitch of 6.7 mm is used, which offers a bigger specific surface area. The activity loss of the catalyst was balanced by adding additional catalyst volume up to the full capacity of the reactor. Later the catalyst layers that had suffered the biggest drop in activity were replaced. This allowed the best possible use of the residual activity in the remaining catalyst. The conversion rate for SO_2 to SO_3, which increases proportional to the catalyst volume, does not present any problem in the downstream heating surfaces in this plant since the cold end of the air heater is enameled [< 460°F (<240°C)].

PUBLIC SERVICE OF NEW HAMPSHIRE MERRIMACK STATION UNIT 1 PROJECT

Merrimack Station Unit 1 is a B&W radiant boiler design with three nine-foot diameter cyclones and a pressurized furnace. Figure 1 shows a schematic of the unit. The boiler fires bituminous coal. The boiler is rated at 815,000 lb/hr main steam flow and 717,500 lb/hr reheat steam flow. Steam outlet conditions are 1005°F. Main steam pressure is 1875 psig; hot reheat pressure is 461 psig. The boiler is equipped with regenerative type air preheaters. Steam temperature control is achieved by gas recirculation and spray attemperation.

This retrofit project consisted of the installation of a high dust SCR system (see Figure 1). The SCR system provided consisted of a single SCR reactor with a bypass designed for 50% boiler flue gas flow. The retrofit of the SCR system was performed on a fast schedule with an engineering release on October 9th, 1998 followed by a contract awarded November 4th, 1998 with scheduled start-up on June 4th, 1999. The actual start-up of the system was achieved two days behind schedule on June 6th, 1999. Merrimack Station Unit 1 uncontrolled NOx emission of 1.34 lb/MMBtu requires year round operation of its SCR to comply with NOx emissions requirements.

Babcock Borsig Power Inc. (BBP, Inc.) had turnkey scope of supply including the reactor, all associated support steel, ductwork, isolation/bypass dampers, expansion joints, access and testing provisions, platforms and stairs, reagent unloading, storage and injection system with complete erection and construction of the SCR system. The initial catalyst charge was supplied by PSNH and installed by BBP, Inc.

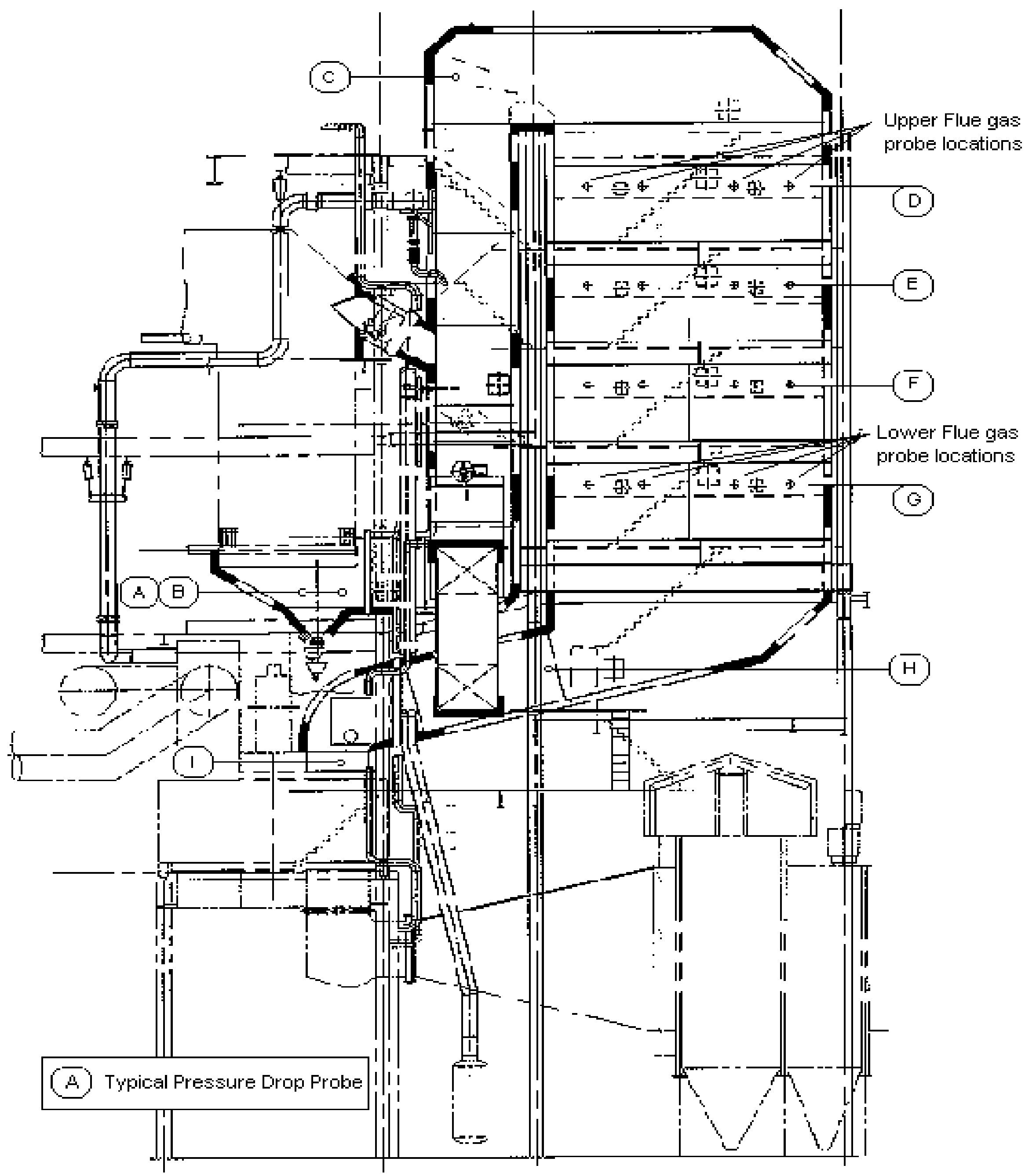

Figure 1 Public Service of New Hampshire Merrimack Station Unit 1

The fuels fired in Unit 1 are generally a blend of high sulfur bituminous coal with either a medium or low sulfur bituminous coal. The sulfur content of the fuel is typically between 0.5% and 2.8% with the ash between 5% and 10%. Due to the levels of CaO in the ESP ash (>3.0%) arsenic poisoning of the catalyst was not expected even with complete flyash recirculation from the ESP's to the cyclones.

The following characteristics define the design basis for the SCR:

- Twelve month per year operation with 2 years between catalyst charges.
- 5 ppm ammonia slip at 88.9% NO_x reduction.
- Inlet NO_x of 1.34 lb./MMBtu.
- Maximum system pressure drop of 3.9 iwc with full complement of catalyst.

BBP, Inc. constructed two a scale models of the SCR installation, including all ductwork from the economizer outlet connection up to the SCR exit duct, to determine the location, number and size of turning and mixing devices to be installed. The two models differed in scale with one emphasizing on flow characteristics and the other on ash distribution characteristics. Tests were performed to assure the required velocity, temperature, NO_x to ammonia ratio and ash distribution would be achieved while minimizing the system pressure drop. Special consideration was given proper mixing and distribution of the flue gas side economizer bypass.

Siemen's plate catalyst with a pitch of 5.4-mm was selected and purchased by PSNH for the initial catalyst charge. The catalyst was designed for 88.9% removal efficiency and 5 ppm ammonia slip with a two year replacement cycle. The catalyst selected has a rate of conversion of SO2 to SO3 of less than 1.5%.

The reagent chosen for the project was anhydrous ammonia. The existing reagent unloading system for the SCR system on unit 2 was utilized for the Unit 1 project. The existing 30,000-gallon aqueous ammonia storage tanks for the SNCR for Unit 1 were replaced with 30,000-gallon anhydrous ammonia storage tanks. BBP, Inc. also provided a leak detection system around the storage and unloading areas. The liquid anhydrous ammonia is delivered to the process from the ammonia storage tanks using pumps. The ammonia is then evaporated in an electrically heated vaporizer. The saturated vapor from the vaporizer is then electrically superheated to prevent condensation during the metering and delivery to the dilution air. The dilution air is provided from the FD fans, taken after the regenerative air heater. The dilution air ammonia mixture is distributed into the flue gas flow via five nozzles. Several mixing devices in the flue gas ducts assure a homogeneous distribution of the reagent and provide additional homogenizing of NO_x concentrations, temperatures and velocities.

The startup of the SCR system was scheduled to take four weeks, with the unit to be placed in commercial operation on July 4, 1999. Due to difficulties with the ammonia pump/vaporizer, the system was not placed in commercial operation until July 20, 1999. During the start-up period the SCR system was operated at approximately a 70% removal efficiency using ammonia vent directly from the ammonia storage tank.

The following are some of the problems that were encountered during the startup and initial operating period.

- The inlet and outlet NO_x monitors required modifications to their seal air gaskets. Using an inputted curve of inlet NO_x vs. boiler load and the plant stack CEM the system has been successfully operated.

- The original ammonia transfer pumps with single mechanical face seals were replaced with seal-less canned motor pumps.
- The bypass guillotine dampers had limit switch problems, resulting in mechanical damage when the switch failed. This problem was fixed with the installation of a second set of switches and a torque-limiting switch on the drive.
- The dilution air system encountered pluggage problems due to ammonia bisulfate salts. This fouling resulted in distribution problems at the inlet face of the catalyst. The cause of this problem was the trace amount of SO_3 carried into the dilution air from air heater leakage. This occurred because the air heater outlet air temperature is below the minimum temperature required to prevent the formation of ammonia bisulfate. Re-routing the dilution air system inlet from the air preheater outlet to the FD fan discharge solved this problem.

PSNH Merrimack Station Unit 1 SCR system has been operational for approximately 12,000 hours. The pressure drop of the complete SCR system is 3.0 iwg, that is, 24% below the predicted value of 3.9 iwg. Rake type steam sootblowers are operated once daily on all catalyst layers of the SCR system. During this period of operation no operating problems have developed. The unit has been inspected several times during outages with no evidence of ash pluggage in the catalyst. The unit successfully passed an acceptance test in May 2000. The ammonia slip, measured using multi point extraction, was half of the design value based on the hours of operation on the catalyst.

PENNSYLVANIA POWER & LIGHT MONTOUR STEAM ELECTRIC STATION UNIT 2 SCR RETROFIT PROJECT

Montour Steam Electric Station Units No. 1 and 2 are rated at 745 MW gross and 755 MW gross maximum continuous load. Units 1 and 2 and were placed in service in 1972 and 1973 respectively. On each unit, the flue gas is discharged from one Combustion Engineering, Inc. tangentially fired, supercritical, combined circulation, pulverized bituminous coal-fired, divided furnace, single reheat, positive pressure, outdoor type boiler. The boiler has been retrofitted with ABB's LNCFS Level III NO_x reduction system, comprising concentric firing, with both close-coupled and separated overfire air. It has a maximum emergency rating of 5,700,000 lb/hr steam at 785 MW gross with superheater outlet conditions of 3830 psig and 1010°F. Reheater outlet conditions are 644 psig at 1005°F.

This retrofit project consisted of the installation of a high dust SCR system, see Figure 2, in conjunction with the SCR retrofit the electrostatic precipitators on Unit 2 were also replaced. The SCR system provided consisted of two identical reactors, each designed to handle half of the total flue gas flow from the boiler. The retrofit of the SCR system was scheduled for operation during the 2000 ozone season. PP&L had opted for early compliance with the pending NO_x emission limits and to sell or bank trading allowances. The installation of an identical SCR system for Unit No. 1 is scheduled for completion prior to the 2001 ozone season.

BBP, Inc.'s scope of supply included the reactor, all associated support steel, ductwork, isolation/bypass dampers, expansion joints, access and testing provisions, platforms and stairs, initial catalyst charge, reagent unloading, and storage and injection system. PP&L's scope included the erection and construction of the SCR system.

The fuel fired in Unit 2 can be any Eastern bituminous coal as defined in ASTM-D-388 as Class II, medium volatile and high volatile A, B and C bituminous coal. There are no spe-

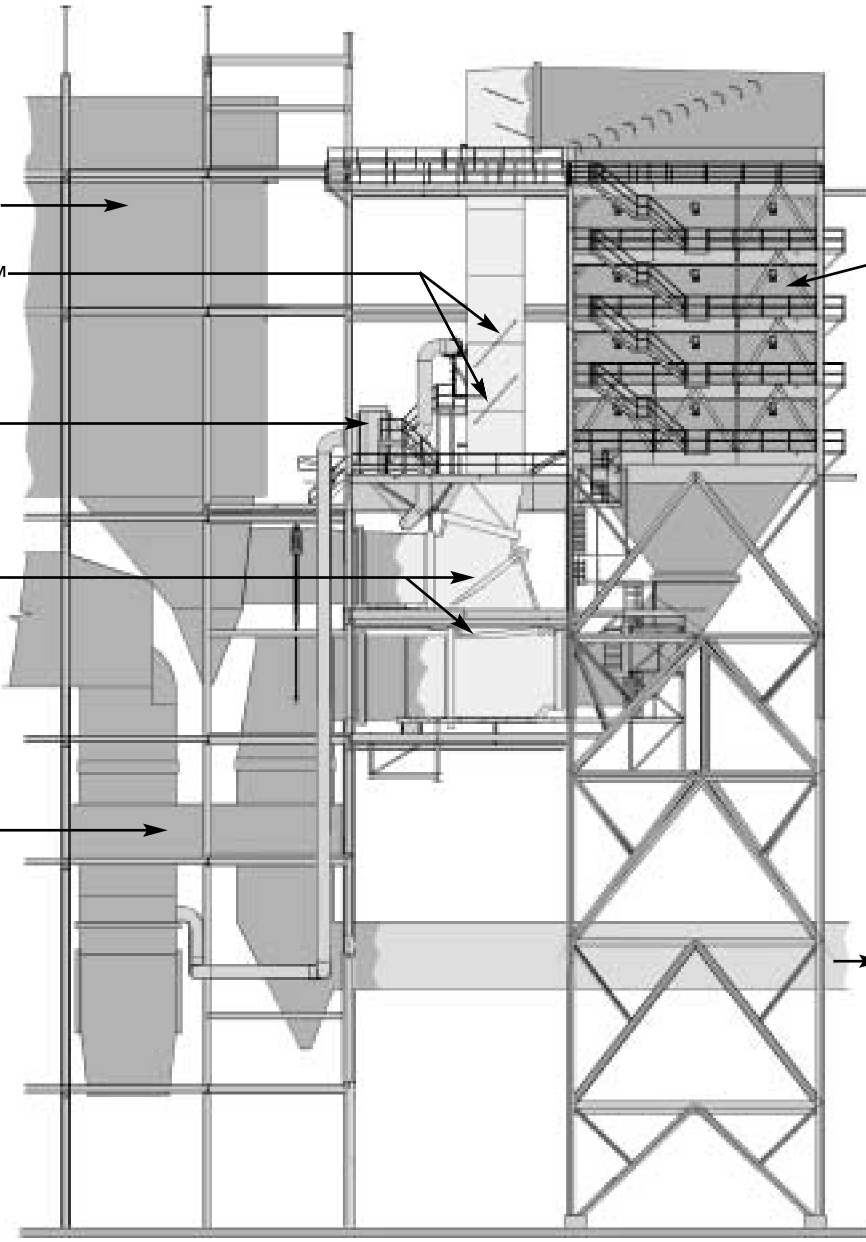

Figure 2 Pennsylvania Power & Light Montour Steam Electric Station Unit 2

cific restrictions to any coal from any mine within the above category. Prior to the selection of the catalyst, an extensive testing program was undertaken to examine the coals most commonly used at the Montour Electric Steam Station. The reported arsenic poisoning of the catalyst at two other plants with installed SCR systems burning similar coals prompted this examination.

This examination found that several of the coals had arsenic to calcium ratios that could lead to rapid deactivation of the catalyst. Some of the coals had over 100 ppm of arsenic and less than 1% CaO. A test program was undertaken to evaluate the feasibility of adding limestone to the coal to control arsenic poisoning of the catalyst. The practice of using limestone addition for the control of gaseous arsenic in flue gas has been successfully applied in Europe on wet bottom and cyclone fired units with continuous flyash reinjection. The addition of limestone was of primary concern to PP&L since the Montour boilers tended to have a high slagging characteristic and additional limestone could aggravate this situation. The test program found the optimum limestone feed rate, which controlled the gaseous arsenic to acceptable levels to prevent early catalyst deactivation without causing any additional slagging problems in the boiler. Based on this study a limestone feeding system was installed to insure that life of the catalyst would be preserved.

The following characteristics define the design basis for the SCR:

- Twelve month per year operation with 2 years between catalyst charges.
- 2 ppm ammonia slip at 90% NOx reduction.
- Inlet NO_x of 0.4 lb./MMBtu.
- Maximum system pressure drop of 7.63 iwc with full complement of catalyst.

BBP, Inc. constructed two scale models of the SCR installation, including all ductwork from the economizer outlet connection up to the SCR exit duct, to determine the location, number and size of turning and mixing devices to be installed. The two models differed in scale with one emphasizing on flow characteristics and the other on ash distribution characteristics. Tests were performed to assure the required velocity, temperature, NO_x to ammonia ratio and ash distribution would be achieved while minimizing the system pressure drop. Special consideration was given to minimizing of ash fallout in the ductwork throughout the gas flow range of 45% to peak load conditions.

KWH's honeycomb catalyst with a pitch of 7.1 mm was selected for the initial catalyst charge. The catalyst was designed for 90% removal efficiency and 2 ppm ammonia slip and to permit eventual twelve-month operation with a two-year replacement cycle. The catalyst selected has a rate of conversion of SO_2 to SO_3 of less than 1.5%.

The reagent chosen for the project was anhydrous ammonia. The reagent unloading, storage, and feed system includes the capability to transfer anhydrous ammonia from trucks (two trucks at a time) as well as rail cars (one rail car per time) to either of two 60,000-gallon ammonia storage tanks. A leak detection system around the storage and unloading areas was also provided by BBP, Inc. PP&L provided a water deluge system to minimize off-site ammonia vapor in the event of a storage tank or pipe leak. The liquid anhydrous ammonia is pumped to the process from the ammonia storage tanks using seal-less canned motor pumps, then the ammonia is injected directly into heated dilution air where the ammonia is evaporated. The dilution air is provided from the FD fans and heated via steam coils. The dilution air ammonia mixture is distributed into the flue gas flow via five nozzles per SCR reactor, and several mixing devices in the flue gas ducts assure a homogeneous distribution of the reagent and provide additional homogenizing of NO_x concentrations, temperatures and velocities.

The startup of the SCR system was not complicated and proceeded without major problems. Prior to the startup an extensive training program was conducted for PP&L's operating and maintenance staff. This training program was a significant factor in minimizing delays or problems during the startup phase.

Prior to bringing the SCR system on line the boilers were brought up to full load after the outage period. The boiler was operated for approximately three weeks prior to the introduction of flue gas into the reactors. This period gave the PP&L and BBP, Inc. startup engineers an opportunity to make system checks and adjustments.

The following are some of the problems that were encountered during the startup period:

- The inlet and outlet NO_x monitors required modifications to their seal air gaskets. While modifications to the monitors were made, the SCR system could not be run at the 90% reduction design set point. Since both the inlet and outlet NO_x analyzers were affected, automatic operation with only the stack CEM for control was not possible. To operate the system during this period, the relationship between ammonia flow vs boiler load to achieve 80% removal efficiency was used as the feed forward signal with the stack CEM used for trim. The removal efficiency of 80% was chosen to avoid the over supply of ammonia due to the inaccuracy of the inlet NO_x relationship.
- The piping arrangement of the dilution air steam coil heat exchangers caused flow stratification entering the heat exchangers, limiting their effectiveness. It was found that temperature set points could be achieved only with both the primary and backup heat exchangers operating. Guide vanes and perforated plate have been installed to correct the stratification problem.
- The damper hydraulic system has had leaks and has required rework in the field to correct. The second unit, Unit 1, will have welded joints to the greatest extent possible. We are still looking for a permanent solution to the leaks on Unit 2.

Montour Electric Steam Station Unit 2 SCR system completed its first ozone season of operation on October 1. During this first season of operation, no operating problems have developed. Rake type steam sootblowers are operated once daily on all catalyst layers in the SCR system. The average outlet NO_x emission rate for Unit 2 during the months of July, August and September was 0.119 lb./MMBtu, 0.0427 lb./MMBtu and 0.049 lb./MMBtu respectively, based on 15-minute average data from the plant CEM equipment. During the month of July the above-mentioned inlet and outlet NO_x analyzer problems prevented lower outlet emissions. Construction on Montour Electric Steam Station Unit No.1 SCR system is currently proceeding and is scheduled to be in operation prior to the 2001 ozone season.

CHALLENGES FOR THE DESIGN OF FUTURE U.S. SCR SYSTEMS

Increased Removal Efficiencies and Reduced Outlet Emissions Rates

At the beginning of SCR development, we assumed that for high dust SCR plants, the maximally attainable removal efficiency was 85%. In the acceptance trials for the high dust SCR Berlin Oberhavel, a removal efficiency of 89.5% with a mean slip of 0.4 ppm (v) was obtained, this experience indicated that removal efficiencies of 90%, or greater, could be achieved with the high dust configuration. The tendency nowadays with high dust SCR plants behind dry bottom furnaces is to design the slip to 1.5 - 2 ppm (v) at end of catalyst life. The objective of the low slip design is to limit the NH_3 content of the fly ash. Depending on the ash content of the coal fired, the NH_3 content of the ash would be below 100 ppm with slip values of 1.5 to 2 ppm (v). This limit is necessary when the fly ash is used in the building materials industry as a raw material for processing. Ammonia contents above 100 ppm could, during the moistening required in processing, lead to an odor nuisance from the ammonia. The new high dust SCR plant in the power station Altbach may not exceed a maximum slip of 1.5 ppm (v) after 16,000 hours of operation. The NOx clean gas value as a half-hour mean value is <0.08 lb/10^6 Btu (<100 mg/m^3). The design removal efficiency amounts to 80%.

Very high removal efficiencies are required in wet bottom boiler plants since very high raw gas NO_x values before SCR are found here. BBP has fitted SCR reactors in plants with raw gas values of 0.98- 1.54 lb/10^6 Btu (1200 -1900 mg/m^3 NOx referred to 5 Vol. % O_2). Design removal efficiencies of over 90% have been achieved with such systems.

The U.S. market requires removal efficiencies of 90% for high dust SCR at an ammonia slip of <2 ppm (v). This places demands on the reagent mixing into the flue gas and the homogeneous inflow into the catalyst are accordingly high. Therefore, BBP provides a special Delta Wing™ static mixing system that provides low pressure drop and high quality mixing and uniform regular inflow to the catalyst in the SCR reactor. This is the precondition for proper operation of the plant. While 90% removal efficiencies can and have been obtained the U.S. market is requiring these efficiencies with ever decreasing inlet NO_x concentrations. These decreasing inlet concentrations are the result of ever increasing firing system technology. With the inlet concentration falling and the removal efficiency constant, the mixing system requirement must be stricter to maintain the low design ammonia slip requirements. The current state of the art outlet NO_x emission rate in Europe on high dust configurations is approximately 0.08 lb/ 10^6 Btu. The PP&L Montour Steam Electric Station Unit 2 installation has reduced this outlet emission rate limit to 0.04 lb/ 10^6 Btu without requiring increased pressure loss for the mixing system. Based on operation data and ammonia flyash concentrations from Montour during its first ozone season even lower outlet emission rates can be achieved on high dust configurations.

PRB Coal and PRB Bituminous Coal Blends

There is no experience in Europe available with coals similar to those of the U.S. PRB coals. The high CaO content in these coals can result in an increased deactivation rate through a blinding process resulting from the formation $CaSO_4$ on the catalyst surface. The extent of this deactivation is currently not completely known. Since PRB coal is inherently a low sulfur coal the concentration of SO_3 in the flue gas should be correspondingly low thereby limiting the formation of the blinding agent $CaSO_4$. Therefore it is assumed that $CaSO_4$ blinding should not be a significant deactivation mechanism when firing PRB coals and PRB blends. However, the practice of blending PRB coals with bituminous coals for sulfur emission control increases the available SO_3 concentrations in the flue gas. The influence of combustion side reactions between sulfur and CaO are currently unknown for PRB blends. The only operational SCR firing PRB coals a cyclone fired unit with lower ash loading rates than dry bottom units thereby reducing the exposure of the catalyst to the potential blinding agents. Currently there are no operational SCR systems firing a PRB/bituminous coal blend. Several slip stream reactors at different PRB and PRB/bituminous blend boilers should help to find the mechanisms that may cause increased deactivation. This testing will assist in finding solutions to counteract any early deactivation. BBP has designed, installed and is operating several slip stream reactors on both PRB coals and PRB/bituminous coal blends. These test reactors will provide long term operating experience on PRB coals and PRB/bituminous coal blends in actual reactor conditions of velocity, temperature and ash.

High Sulfur Coals and Pet Coke Blends

There is little experience with SCR systems downstream of boilers that are firing fuel blends consisting of pet cokes and bituminous coals. Pet coke is an attractive fuel due to its low price and high heating value. Many pet coke analyses show high vanadium concentrations in the fuel often 5 to 10 times greater than that of bituminous coals. The vanadium content of the fuel has a large impact on the SO_2 to SO_3 conversion rate that occurs in the boiler, and the vanadium also accumulates on the SCR catalyst. This relationship between fuel vanadium content and SO_2 to SO_3 conversion in the boiler is well demonstrated on units firing heavy fuel oils. The vanadium in the flue gas may increase the reactivity of the catalyst resulting in an increased conversion rate SO_2 to SO_3 of the catalyst. The exact effects of firing a blend of pet coke with coal is not completely understood at present, it is possible that the ash from the coal will mitigate the vanadium. It is also possible that boiler and catalyst will have an increased SO_2 to SO_3 conversion rate that will require the downstream equipment of the SCR system to handle high SO_3 levels. These high SO_3 levels can have a big impact on the operation and maintenance of the downstream equipment. The air heater may have to be equipped with enameled heating surfaces, at least at the cold end. The SO_3 removal of the WFGD scrubber is limited, so the SO_4 - aerosol issue downstream of the WFGD has to be considered with pending PM2.5 regulations if the vanadium results in greater SO_3 conversion in the boiler and catalyst. The composition of the catalyst regarding the initial SO_2 to SO_3 conversion rate has to be carefully designed to find an optimum between required catalyst volume and acceptable conversion rates at end of lifetime of catalyst. In addition to the vanadium, the pet coke blends have sulfur contents beyond known operating experience. The European experience with sulfur content of the fuel is limited to bituminous coal with max sulfur contents of between 2% to 2.8%. The pet coke blends contain sulfur contents of between 5% and 6%. It should also be noted that many U.S. bituminous coals contain sulfur at levels greater than those of the known European operating experience. Catalyst deactivation rates with coal sulfur contents twice that of current European experience is unknown. The only known operating SCR experience with fuel sulfur contents this high is with pet coke, Orimulsion, and heavy fuel oils. BBP is currently investigating these relationships with full scale test firing of various pet coke and coal blends, and measuring SO_2 to SO_3 conversion in the boiler and on test catalyst coupons.

High Arsenic Coals

In general, German and European coals usually have relatively low arsenic concentrations in the coal. There is experience available with high arsenic concentrations in the flue gas with wet bottom furnaces. Work with experimental slip stream SCR plants behind wet bottom furnaces in Germany rapidly made it clear that high catalyst deactivation rates are obtained with a high proportion of gaseous arsenic present in the flue gas. The high arsenic concentrations in the flue gas range of 500-1000 µg/ cubic meter was attributable to the 100% ash recirculation from the ESP's into the wet bottom furnace. Flyash recirculation is a standard operating method in these plants due to high carbon contain of the flyash and to reduce the overall flyash removal quantities. Of the various methods available to minimize the gaseous arsenic concentrations in the flue gas, BBP decided in favor of ash extraction and has good experience with this method in the high dust SCR plants at Walheim and Oberhavel. The extraction method removes approximately ten percent of the fly ash from the recirculation cycle, preferentially the highly arsenic burdened fine fraction, and the removed flyash is disposed of. The arsenic concentration in the flue gas was lowered with the extraction method so much that the deactivation behavior of the catalyst is only slightly inferior to that experienced in dry bottom furnaces. Other European experience is available with limestone addition to the coal to reduce gaseous arsenic concentration in the flue gas. The limestone addition experience in Europe has been applied at some U.S. dry bottom boilers where considerable arsenic concentrations in the coal (sometimes ten times higher than in Europe) would lead to high gaseous arsenic concentrations upstream of the SCR catalyst. BBP has obtained significant reductions of the gaseous arsenic concentration with limestone addition at operating plants in the U.S. (see Figure 3). These relationships are specific to the individual boiler and must be determined on a project by project basis.

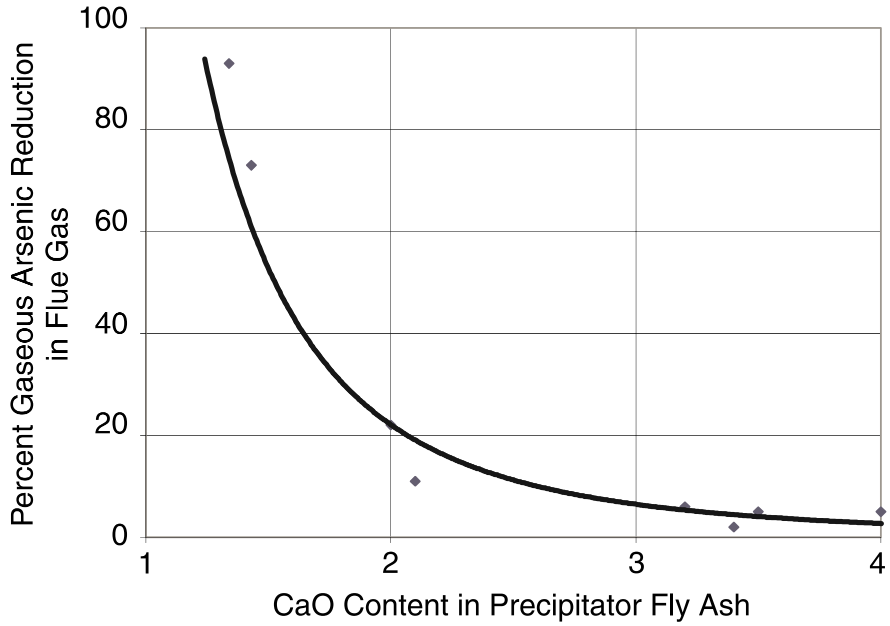

Figure 3 Effect of Limestone Addition for Control of Flue Gas Gaseous Arsenic

Other Challenges

Other challenges facing the SCR designer will be the selection of reagent systems between anhydrous ammonia, aqueous ammonia, and urea based systems. The final selection of the reagent system will depend on economic and public opinion requirements. Currently anhydrous ammonia is the most commonly selected reagent type, but due to concerns over safety this may change. If the use of aqueous ammonia is chosen, the strength of the ammonia mixture will have to be limited to 20% ammonia by weight to avoid OSHA hazardous material regulations. The quantities of aqueous ammonia needed for many of the large installations under design would require the installation of 250,000- to 600,000-gallon aqueous ammonia storage tanks, with the unloading of 6 to 8 railroad tank cars per day. The storage and handling of aqueous ammonia on this scale is not commercially common. The application of urea-based systems on this large scale will require considerable scale up success based on current system size.

The management of catalyst and the determination of the volume of catalyst to be installed are currently based on a fixed catalyst lifetime, which implies a fixed removal efficiency and ammonia slip at end of lifetime. The normal reactor design has an initial number of layers required for the fixed catalyst lifetime design and a single spare layer for catalyst management. By fixing the catalyst lifetime, the different layers of catalyst in a given reactor could have shorter catalyst element lengths that provide less catalyst volume in a layer. This approach does not maximize the catalyst volume in the reactor. If all catalyst layers were supplied with the maximum catalyst length, then the catalyst lifetime would be the open variable, depending on available catalyst volume and catalyst potential. The maximizing of the catalyst length in every layer does impact operational costs due to increased pressure loss in the SCR system. The final decision of catalyst volumes and lengths must be made based on economic analysis of the specific plant, including outage costs, catalyst installation and removal costs, etc.

CONCLUSIONS

The experience gained in Europe with the installation of high dust SCR systems has been and is currently being successfully applied to the U.S. market. However, several future challenges exist in the U.S. market concerning fuel differences and operating conditions. The determination of fuel impact on catalyst deactivation for these new fuel ranges is currently under investigation using slip stream reactors and coupon testing. The current requirement to lower final outlet NO_x emission rates has taken its first step with successful operation at PP&L Montour Unit 2. Further testing at Montour may provide additional progress to even lower outlet emission rates.