

**NO<sub>x</sub> Control XIV Conference**  
**March 12 - 14, 2001**  
**San Diego, California**

**I. Boiler, Burner, & Turbine Single Digit NO<sub>x</sub> Limitations -**  
**Ted Guth, Consultant**

Ted pointed out that in Southern California, retrofit rules have been established for most technologies that are at single digit NO<sub>x</sub> levels for gas firing. This area of the country is the only area that is not in compliance for NO<sub>x</sub>. Since California hasn't built very much in the last 15 years, existing units had to be targeted. These levels are setting the EPA BACT levels that will apply to other areas that are in non-attainment for other criteria pollutants (like ozone). Gas is the BACT fuel. If gas is available, it is likely to be required in California, although last year, when gas prices hit \$80/MMBTU, cost factors were allowed in BACT. These levels are being applied to units down to 20 MMBTU/hr. In addition, when subject to BACT in a non-attainment area, the target is moving until the moment that the permit is issued. This means that there is risk in ordering equipment before the permit is received as the required technology could be changed by the permitting agency.

Single digit NO<sub>x</sub> burners are high, induced FGR, gas burners that are typically deployed. SCR with additional catalyst can get down to low NO<sub>x</sub> levels. SCONOX is being used on gas turbines to get down to 2 ppm. It is also being tested on a gas boiler at similar levels. Coal units are looking at 20 - 30 ppm with SCR (and 98% SO<sub>2</sub> removal). Part of the driver is that for most of California, offsets are required. These have to be purchased. The cost of purchasing these offsets can often be more than the cost of the equipment. Lower emission levels can save on the cost of offsets, even at the risk of operating problems going forward.

**II. Technical Forum Results -**  
**Jim Kyle, Dow**

The topics for discussion were selected by vote. Ultra low NO<sub>x</sub> burners, available retrofit technology, working through NSR, and backend technology. Ken Price of P&G, Larry Day of Nationwide Boiler, Debra Lane of Westvaco, and Bruno Marubito of TrigenCinergy were the panel members. Larry started out with the statement that although single digit NO<sub>x</sub> burners are available, it isn't always that simple. These are not applicable to all boilers and there are cases where a combination of burners and SCRs are more economical. Ken Price noted that dynamic conditions need to be taken into account. They are trying to get burner manufacturers to make guarantees for load changes of 1% per second. Tuning up such as system is critical. Units that get out of control during load changes can

be “off line” for over half an hour for a 5 minute load change. This is costly to the owner. Bruno pointed out that maintenance is becoming more expensive as units are being asked to last longer. The NSR rules, as they are now interpreted by EPA, cause triggers for BACT applications. Simple things like knowing the cost of the maintenance will now be critical. The impact on the life of the boiler must be assessed. Communications is critical in assessing NSR impact. Early in the project, these assessments must be made and discussed with the permitting agencies so that any possible problems can be ironed out before major funds are committed. These assessments also set up the requirements for the equipment that need to be communicated to the suppliers. One question was that adding low NOx burners should reduce emissions and thus should not trigger NSR. Doug Grano of EPA indicated that there is policy in that regard, but it is still a case by case basis review requirement.

John DeLacy of Coen led the manufacturers panel. Panelists included Gil Sy of Forney and Tim Webster of Todd. The topics that were suggested were reviewed including project specification requirements, variable operations and maintenance, and sustainable performance. Gil pointed out that the owners need to get as much information about the project up front. These need to be communicated to the suppliers so that the equipment can meet the owners needs. Compatibility with existing equipment is critical. As was pointed out by the owners session, good communication is essential. Working with the suppliers in some joint manner is preferable to parts purchasing. Compliance testing is also an important part of the project. Adequate time needs to be allowed for commissioning and testing to be sure that the equipment meets the process needs including low changes, etc. Ted noted that owner guarantees of process parameters as well as equipment guarantees are desirable. These might include fuel specs, gas flows and temperatures, load ranges, etc. Commercial terms and conditions need to be established before purchase orders are written. Key personnel need to be identified early and brought into the project early so that all understand what is wanted (and needed). Schedule issues, training, facility availability, etc. all need to be identified early. As emissions are tightened, it is more critical to treat the activity as a real project rather than as replacement parts. Understanding the costs and complexities of low NOx systems is an important education process. In turn, owners should work with suppliers to educate regulators. This ties in with Debra Lane’s comments about talking to regulators early and often. A final recommendation was to form an alliance amongst the parties to assure that all are working to the same goal. The question of upset conditions was raised. This gets to the definition of upset conditions. This will vary with what the particular state has gotten approved in its State Implementation Plan. Typically more sensors and controls as well as additional software will be required as emission requirements are applied to upset conditions.

Tom Fitzpatrick of SFT, Bill Randall of Randall Associates, Siva Sethuraman of Process Combustion, and Jim Ansell of Black and Veatch were the panelists. The topics were what people need to be on the team, does the team come before the spec or the spec before the team, and what are the five key questions for the A/E. People include the project manager, the chief engineer, the operations people, the environmental manager, the financial people, the legal and insurance people, the real estate people (for new plant), the community relations people, R&D (for newer technologies), and government affairs people. As was pointed out by the other forums, communications is the key to success. Setting up the team before the specification promotes more flexibility and identifies more options. Putting the specification first creates the solution first and is less flexible. The five questions that were selected

were:

- what experience in this type of project
- what personnel
- what scope and schedule
- what project management procedures
- what fee structure and flexibility

### **III. The Latest on NO<sub>x</sub> Regulations and Impact**

**Doug Grano, EPA,  
Jake Cox, Black & Veatch, and  
Bill Randall, Randall Associates**

The panel consisted of Doug Grano of EPA, Jake Cox of Black & Veatch, and Bill Randall of Randall Associates. Doug Grano went through the litany of potential negative impacts of NO<sub>x</sub> emissions. Doug noted that the ozone transport commission was set up by Congress consisting of 12 northeastern states and DC to discuss ozone transport in the northeast region. One of the outcomes was the 1994 memorandum of understanding which set up 3 phases for NO<sub>x</sub> control on boilers, turbines, and heaters. This also set up a regional trading system for NO<sub>x</sub>. The NO<sub>x</sub> SIP Call was upheld by the courts and calls for 0.15 lb/MMBTU for utility units and 0.17 lb/MMBTU for industrial units by May 2004. Under the CAA Section 126, some states can petition the EPA for relief due to pollution transported from other states. The compliance date for upwind states in May 2003. It remains to be seen if this discrepancy is corrected. There are some areas in the US that are not able to meet the current 1 hour ozone standard. Southern California, the coastal northeast, Houston, and the Great Lakes areas are the primary locations. This driving the overall thrust for additional NO<sub>x</sub> control, in spite of the fact that all but LA are in compliance for ambient NO<sub>x</sub>.

Jake Cox covered the states responses to the NO<sub>x</sub> SIP Call. Sect. 110 of the 1990 CAA amendments gave the EPA the authority to review and call in state implementation plans which would potentially allow interstate transport of pollutants or would be inadequate meet NAAQS. EPA determined that 0.15 lb/MMBTU could be achieved at a cost of less than \$2000/ton of NO<sub>x</sub>. EPA created a model rule with state budgets. Each state must submit a plan that substantially achieves the budget levels established by EPA. On Dec. 26, 2000, EPA stated that 11 states had failed to provide adequate evidence of a compliant SIP. Sanctions could be imposed in something like 18 months from Jan.25, 2001. These include 2/1 offsets for new sources, loss of highway funds, and imposition of Federal Implementation Plans (FIP). The bulk of the northeast and Missouri are deemed to be either approved or close to approval. The mid-west and the south were basically in the 11 states and DC (the SIP "dirty dozen").

Bill Randall stated that his primary goal was to raise questions on NO<sub>x</sub> permitting and his secondary goal was to hold those questions until the permitting session later in the week. Bill pointed out

that there a variety of issues involved in obtaining a permit and not all of those are technical in nature. By reviewing the process and the requirements and the variability of operations, it may be possible to propose plans that achieve the goals of the regulations at a more optimal cost. Seasonal fuel switching, trading, buying allowances, etc. are all potential strategies. There are several regions in the country where trading regimes are established. Prices have varied from \$100,000/ton in California during its energy shortage to a few hundred dollars per ton. Currently in the northeast, trades are occurring at around \$1500/ton. Credits can be generated by over control in certain areas. These can be sold providing revenue to a project. Sources other than boilers and heaters can be tapped, such as trucks, construction equipment, railroads, boats, etc. From all of these sources, a plan can be developed which can meet the overall requirements of the regulations for permits.

#### Manufacturer's Equipment Development Panel - Russ Moser, ABMA

Panel members were Tim Webster of Todd, Kevin Anderson of Coen, Bob Stemen of ABCO, John Pratapas of GTI, Gil Sy of Forney, and Greg Imig of McBurney. Tim briefly reviewed the basics for NO<sub>x</sub> formation and the potential techniques resulting in lower NO<sub>x</sub>. Single digit NO<sub>x</sub> values are associated with gas firing as fuel NO<sub>x</sub> is not a factor in gas firing. Dilution with flue gas along with staging was sufficient to get gas burners down to 30 ppm. To get lower, elimination of prompt NO as well as thermal formation is needed. As prompt NO is favored by fuel rich zones (due to fuel fragments), a simulated premix zone is created in which a rapid mixing is deployed with induced gas recirculation to control temperature. Gas recirculation levels of 25 - 30%. This level can be induced by the natural gas pressure that is available on delivery, thus reducing the additional fan power that would normally be required for gas recirculation.

Kevin covered two of their applications. The first was the QLA burner for water tube boilers up to 220 kpph. This burner uses a premixing chamber prior to introduction to the furnace. A small amount of gas for stabilization is sent through the central core. A small amount of gas is also staged, along with a movable central plug for flexibility during load changes. Low excess air is required. Controls are used on the fuel/air metering, gas recirculation, core modulation, and gas flow staging. The turndown is 12/1 (although the NO<sub>x</sub> level is not maintained at 1/12th load). For fire tube boilers, the ULN burner is used. No premixing is used. The fuel is divided into several injectors. Slow mixing is used. Additional flue gas recirculation is used to get the equivalent NO<sub>x</sub> performance. However, the controls are much simpler. Safety and stability are important issues. The lower the emission rate, the closer to stability limits of the flame and the more difficult the control problem becomes.

Bob reviewed the ABCO experience in selecting burners for their boiler designs. There are two commercially available technologies – 9 ppm burners and SCR. The typical conditions that were discussed in the manufacturers forum are evaluated. Depending upon the anticipated operation, burners or burners plus SCR are selected. The latter gives additional operating flexibility at additional cost. Custom designed units give the 9 ppm burners a better chance. Eliminate, where possible, refractory surfaces as they retain heat which promotes NO<sub>x</sub> formation. Bob's recommendations included good communications of the requirements, life cycle cost evaluations, and long term emission regulation

analysis.

John Pratapas covered work on their forced internal recirculation burners with Detroit Stoker. This burner uses a combination of premixing, staging, interstage heat removal, and induced flue gas recirculation. There are no moving parts. In the demonstration units, the burner has been able to maintain performance over a 4/1 turndown ratio with a fairly simple control system. John also covered the methane denox system that was used at Cogentrix. Detroit Stoker is the licensee and supplier. An application to MSW will be demonstrated in Japan. Boise Cascade has put the technology on a bark fired boiler (300 kpph). The system has been in operation for 10 months. Typically a 50% NO<sub>x</sub> reduction is achieved.

Gil Sy noted that Forney does not have an ultra low NO<sub>x</sub> burner for commercial sale at this time. They are using a combination of CFD, chemkin, and a 60 MMBTU/hr test rig for development. He noted that they would like to partner with owners in the application of low NO<sub>x</sub> burners. Low NO<sub>x</sub> systems cost more than simpler burners. These systems cost more to operate. Compliance testing, tuning, maintenance are all increased to stay within regulatory limits.

#### V. SCR, SNCR and Other Control Technologies - Jeff Smith, ICAC

The panel consisted of Vincent Albanese of Fuel Tech, Russ Goerlich of CRI Catalyst, Mike Durilla of Durilla, Anthony Licata of Babcock Borsig, and Rich Oegema of Alstom Power (Environmental Systems in Knoxville). Vince covered the Fuel Tech NO<sub>x</sub>OUT process which uses urea as an SNCR system. Of the 300 world wide installations, about 270 have been retrofits and, of those, 240 were for industrial applications. Various cap and trade regimes are proposed for NO<sub>x</sub>. In such a system, the lowest cost reduction systems are taken first. Fuel Tech is also offering urea base SCR and combination SNCR/SCR systems for certain small industrial applications. Using a roughly 15% capital charge rate, the costs for several applications ranged from \$1000/ton up to about \$3000/ton. Vince noted that smaller units will have higher costs per ton and definitely need to evaluate buying credits as opposed to buying equipment.

Russ covered the application of a new Shell SCR catalyst. At a particular application, the SCR system was to be retrofitted onto two new boilers (600 hp). These units fed flue gas to a single SCR. The exit gas temperature was 280 F. The low NO<sub>x</sub> burners supplied with the boilers did not meet the guarantee levels for CO and NO<sub>x</sub>. The units were installed at a federal prison in the Mohave Desert in the summer. With the addition of the SCR system, NO<sub>x</sub> levels have been below 3 ppm.

Mike pointed out that Engelhard supplies the catalyst to the SCR systems supplier. That puts that a further step removed from the ultimate customer needs. The permit is the key starting point for the actual requirements. The solution must be considered from an overall system approach. Some of the developments are to look at different catalysts in succession to either get more reduction or to minimize ammonia slip. Different catalysts have different optimal temperatures for NO<sub>x</sub> reduction. As the temperature drops through the catalyst bed, it is possible to utilize different catalyst for best

performance. As catalyst ages, slip goes up while holding NOx levels constant. An alternative approach is to control to a level of ammonia slip. In the early years, excess reduction will occur. In such cases, potentially salable NOx credits can be generated.

Tony Licata pointed out that Babcock Borsig is the result of the merger of five companies including Riley, Deutsche Babcock, Steinmueller, and others. The boiler applications for this presentation are the larger, coal fired boilers. SCR reactors are built up of modules and layers depending upon the reduction requirement, the catalyst life, and the mode of operation. Two key considerations are gas distribution and fuel characteristics. Most of the idealized curves for ammonia slip and NOx reduction do not show the impact of poor gas distribution. Poor gas distribution changes the residence times, the gas compositions, and the ratios of the reactants. These are often different from the ideal design performance. Flow modeling is critical to the success of these reactors in actual commercial use. An ammonia flow distributor is good practice which gets good gas flow distribution as well as good ammonia dispersion. The closer to uniform flow, the better the performance and the longer life of the catalyst. The other consideration is the fuel characteristics. The fuel is typically the source of poisons for the catalyst. Sulfur leads to ammonium bisulfate. Low calcium leads to arsenic poisoning. High calcium leads to calcium sulfate blinding. A complete fuel analysis is required to assure these problems are addressed. Of course, SCRs add pressure drop. In retrofit applications, the fan capacity is often the critical auxiliary piece of equipment.

Rich noted that SCONOX is an alternative to ammonia bases SCR. It requires a regeneration gas to regenerate the catalyst which is basically an oxidation type catalyst. For gas fired applications, guarantee levels of 1.5 ppm are made. The Alstom license is for gas turbines. CO and VOCs are oxidized. SO2 is captured in a guard bed. There is no ammonia slip. The catalyst is loaded on a series of shelves that are located between isolation dampers. During operation the flue gas passes over the catalyst for cleanup. Sections of the catalyst are isolated from the flue gas by the dampers and a regeneration gas is passed over the catalyst. After regeneration the catalyst is re-exposed to the flue gas. At any one time, one quarter of the catalyst is being regenerated. The catalyst is coated with potassium carbonate which absorbs the oxidized compounds. A reducing gas regenerates the potassium carbonate and drives off the absorbed nitrogen compounds as molecular nitrogen. Steam reforming of a hydrocarbon provides a regeneration gas to supply the required amount of hydrogen for regeneration. The regeneration gas is mostly steam with some non condensables. The steam can be condensed to recover the water. In regard to a question on the percentage removal, Rich noted that catalyst saturation tends to limit the inlet to 50 ppm which is reduced down to 2 ppm. Higher inlets would not economically result in 90 - 95% reduction.

## VI. Hardware/Software Issues Relating to Upgrading DEM/DAS - R. Constantine, Forney

Bob noted that some industrial boilers will have to upgrade their CEM systems from part 60 to part 75 if they are in one of the trading programs that will result from the NOx SIP Call or other regulations. Part 60, Appendix B, contains the testing requirements for certification. Appendix F contains the maintenance and reporting requirements. These are strongly influenced by the individual

permit. These vary considerably from site to site. Part 75 was originally applied to the “acid rain” program, which was national in scope. These requirements are in addition to the Part 60 requirements. As more NOx trading programs become authorized, more Part 75 requirements will be seen. Reporting requirements are greatly increased under Part 75. Hourly conditions for the instrument must be reported. The CEM data is the “gold standard” that backs up not only the compliance data, but also the availability (and thus value) of allowances. Under Part 60 emissions were reported in lb/MMBTU. Under Part 75, lb/hr is the appropriate requirement as allowances are on an actual weight basis. This means an accurate flow meter is required (typically on the flue gas). Frequency of valid data reporting increases to 3 (and some times 4) data sets per hour with 100% data capture. For missing data (CEM down), the requirements are to supply missing data in 3 tiers (between 95% and 100%, between 90% and 95%, and less than 90%). This implies additional data acquisition systems are in operation or other means have to be taken to get the missing data. Prior requirements were to supply missing data when the monitor was down more than 45% of the time. Data accuracy has to improve from 20% to 10%. Calibration testing with 3 point linearity and 5% accuracy will be required. Greater attention, including documentation, will be needed for the upgraded monitor. Daily calibration will be required. A written quality assurance plan will be required that provides for maintenance procedures, reporting and documentation procedures, calibration procedures, and certification procedures. Help in understanding the new requirements can be obtained from several sources including the air permit, the trading program, the epa website, the local regulatory agencies, the CEM vendors, and specialist consultants.

## VII. Catalyst Design for NOx Reduction

The panel consisted of Kristi Morris of BASF, Julie Crowe of Hitachi Zosen, and Tom Stobert of Cormetech. Tom noted that Cormetech is a joint venture between Corning and Mitsubishi Heavy Industries. They provide catalyst for SCR systems. Catalyst is manufactured in the US. Just-in-time catalyst delivery, catalyst guarantees, start up support, and catalyst recycle are featured. Honeycomb blocks are extruded into blocks that are bundled and load into steel frames for shipment to the customer. The advantages of honeycomb catalyst are efficient geometry and high resistance to poisoning. In system design, SCR location and orientation, ammonia system, and process conditions are the key factors. For clean fuels, the catalyst can operate at lower temperatures as the risk of bisulfate formation is minimized. For sulfur bearing fuels, a higher operating temperature is desirable. Periodic replacement of catalyst will be needed as the catalyst is degraded by poisoning, aging, and fouling (or blinding). Common poisons are sodium, potassium, chromium, phosphorus, arsenic, selenium, and potentially vanadium (as a catalyst for bisulfate formation which fouls the catalyst). In all systems, there is a coupon section where a sample of the catalyst can be removed and replaced. This sample is then sent back to the Cormetech labs for analysis to aid in determining remaining life in the catalyst as well as any potential problems.

Julie Crowe presented the Hitachi SCR system. Hitachi Zosen is different from Babcock Hitachi. They have progressed from pellet type catalyst to plate type catalyst to honeycomb type catalyst. The openings are triangular in shape compared to the square openings of the Cormetech catalyst. These systems have been applied to a wide range of gases including all types of boilers, gas

turbines, diesels, refinery heaters, incinerators, etc. On gas turbines, 1.5 ppm NO<sub>x</sub> at 12% O<sub>2</sub> has been guaranteed. Hitachi Zosen does system and equipment design and supply as well as catalyst. Catalyst delivery times are 6 - 8 months. Catalyst is manufactured in Japan and shipped to the US.

In the interim, several questions concerning poisoning and limitations were raised. The arsenic question was raised. Past history of coal ash analysis would be used as a guide for the approximate levels of arsenic to be expected. Water in various quantities slowly degrades catalyst. There were no specific limitations on moisture content in the flue gas other than to say that the catalyst works better with lower moisture.

Kristi Morris pointed out the BASF owns boilers, but also makes catalyst. BASF has production facilities in the US that are impacted by NO<sub>x</sub> regulations. BASF provided the first de-NO<sub>x</sub> catalyst for nitric acid plants in the 60s. While they have supplied SCR catalyst to all power applications, they specialize in waste to energy plants and chemical plants. As a chemical plant owner, they are especially familiar with chemical plant problems. Cat crackers, incinerators, nitric acid plants, etc. have all been supplied with BASF catalyst. Key parameters are gas flow conditions (temperature, pressure, flow rate, & composition), removal efficiency, location, process requirements, and physical site constraints. The poison list for power boilers includes arsenic, phosphorus, sodium, potassium, HCl, and heavy metals. As an owner, BASF evaluated the various types of catalyst supply. These included honeycomb, plates, and extrudates. BASF selected the honeycomb arrangement as the lowest cost and most flexible design. Lower pressure drops, arrangement flexibility, and ease of extension. BASF does take back catalyst for recycle. BASF offers custom made catalyst for SCR applications in a wide range of industrial settings.

#### VIII. Operating Cost Effective, Low NO<sub>x</sub> Installations - Larry Day, Nationwide Boiler

Nationwide primarily supplies rented boilers. In California, low NO<sub>x</sub> has been an issue since 1983. A refinery was in need of a package boiler, but needed 0.1 lb/MMBTU on gas (83 ppm). This was considered to be very low at the time. Air staging in a "D" boiler was used to meet the regulation. Over time, Southern California lowered the limits down to single digit NO<sub>x</sub> levels. Nationwide has experience with 15 different boiler manufacturers and 29 different burner models in over 1000 low NO<sub>x</sub> start ups. The current fleet of rental boilers is equipped with 30 ppm NO<sub>x</sub> equipment. Front and side wall ports, steam and water injects, gas recirculation, staged combustion, burner modifications, premixed burners, and SCRs have all been utilized. Important considerations include unit efficiency, turndown, gas compositions, controls, and equipment age. The first step to add, or improve, a low NO<sub>x</sub> system, is a tune-up. This is important for baseline performance information. Safety and efficiency concerns can also be addressed. The baseline also identifies the gap that is needed to meet the current regulations.

Often times, simple fixes can be deployed to meet the regulation. One of the easier modifications was to apply induced flue gas recirculation to the gas burners. NO<sub>x</sub> levels of 25 to 30 ppm can be achieved. For further reductions, low NO<sub>x</sub> burners with high FGR and premixing are needed. Back end technology can also be applied. The choice is dependent upon the application. Experience on a unit in Fresno demonstrated a low NO<sub>x</sub>, high excess air burner from Alzeta. The fan size was doubled with the high excess air. The NO<sub>x</sub> level was 6 - 8 ppm. Existing, simple controls were adequate. CO was 5 ppm. No FGR was required. However, a 2 - 4% energy penalty was taken due to the high excess air. The start up was managed in one day. In another example with the same burner, start up took 3 months. With the high gas flows, there are often hidden problems such as flow distribution, stability, vibrations, harmonics, etc. Nationwide has been using X-ID tubing in their fire tube boilers. This gives some inside roughness that improves the heat transfer rate, thus requiring fewer tubes. As a result of a refinery installation for a 200 kpph in California, Nationwide now offers an SCR packaged system for rental boilers. The unit has been certified in Southern California. The catalyst package fits into the base of the stack. Shell catalyst was used due to the low temperature application and the low pressure drop requirement.

## IX. New Systems and Advanced Technologies

The panel consisted of Richard Kopang of GE-EER, Ron Lutwen of SFT, and Leslie Witherspoon of Solar Turbines. Richard covered a layered NO<sub>x</sub> approach for high fixed nitrogen fuels. This approach uses overfire air and SNCR after the low NO<sub>x</sub> burners. In addition, fuel reburning can also be deployed. In a catalytic cracker, the regeneration step often involves a waste gas that can have nitrogen bearing gases that are normally burned out in a CO boiler. For a cyclone unit firing coal, coal reburning is being deployed on a unit in the Southeast. CO boilers fire a gas that is low in heating value with gaseous nitrogen compounds (including NO<sub>x</sub>). They often have refractory areas to provide areas for heat stability to avoid flame stability problems due to the variability of the fuel. In one refinery application, the fuel gas was high in ammonia that burns with the fuel to NO<sub>x</sub>. Typical uncontrolled NO<sub>x</sub> was 350 ppm, while 70 ppm was desired. The existing overfire air ports were too close to the burner zone and were actually detrimental to the NO<sub>x</sub>. The port was moved farther downstream to get significant reductions. The addition of SNCR with urea injection was able to get down to the required levels. Interest in gas reburning has waned with the increase in natural gas prices. Coal reburning has now been demonstrated using coal as the reburn fuel. Reductions of 40 - 55% can be achieved. Key correlating parameters for coal are volatility and calcium availability. A 30 MW cyclone boiler was retrofitted with coal reburn. Cyclone units are inherently high NO<sub>x</sub> emitters as the goal is to slag the ash in the coal at high temperatures. At full load, this unit produced nearly 1.5 lb/MMBTU of NO<sub>x</sub>. (10 times the current standard) Roughly 50% removal was achieved with the coal reburn system. An 800 MW, tangential fired, twin furnace is planned for retrofitting. With overfire air modifications, and coal reburning, a 50% reduction is expected.

Ron Lutwen reported on the LoToxNO<sub>x</sub> removal system. A demonstration at the Medical College of Ohio has been installed on a stoker boiler firing Ohio coal. The college has 3 x 70,000 lb/hr and one 40,000 lb/hr coal fired units that all lead to one flue. After a dry FGD system, ozone is added

to the gas to oxidize NO<sub>x</sub> to N<sub>2</sub>O<sub>5</sub>. Mercury, CO, and VOCs are also oxidized. The oxidized products are scrubbed in a caustic scrubber. Ozone generation is a high energy cost. In areas where electric costs are low, or self generated, this is not too severe a penalty. If the commercial/industrial electric rates are high, the costs could be prohibitive. The advantages are a relatively low capital cost along with the reduction of other pollutants. Initial operating difficulties have been a problem with the variable speed drive, inadequate well water for cooling, and delays in getting the Title V permit. This is expected to occur in the next 4 - 6 weeks. A 6 month test program is planned.

Leslie presented Solar's Dry Low NO<sub>x</sub> Technology for mid range gas turbines (25 MW and smaller). Federal BACT is still 25 ppm in most areas of the country. This is due to the fact that SCR or SCONOX is not really cost effective on small size units. Federal LAER is down to 2 - 3 ppm. The main competitors are GE (Nuovo Pignone) and Alstom (STAL and Rugby). There have been some guarantee levels at 9 - 15 ppm under unique conditions. Hitachi has deployed a catalytic combustor to get NO<sub>x</sub> levels at about 3 ppm. Liner technology and injector optimization have been used to reduce NO<sub>x</sub>. Catalytic combustors are also being studied. The development goals are to improve system robustness. Dry, low NO<sub>x</sub> systems operate closer to the lean extinction limits giving flame stability considerations. Increasing the operating range is desirable. Increasing compliance margins can add risk in that local regulations can now permit these levels, while doing so may avoid triggering an SCR. Cost figures range from \$165 K for dry low NO<sub>x</sub> systems (5 MW) to \$230 K for SCR to \$1.1 MM. Operating costs range from \$41 K/yr for DLN to \$300 K/yr for SCR and \$600 K/yr for SCONOX. On a \$/ton basis, the costs are \$370/ton for DLN to \$1500/ton for SCR to \$8000/ton for SCONOX. One of the new developments has been the Catalytica XONON system for a very low NO<sub>x</sub> burner. This is a natural gas only, catalytic burner that operates down to 80 - 85% load. Price level has been on same order as SCR. Only one demonstration has been done in the US. The unit is no longer operating as the plant owner reused the space for other products. Inquiries are up for cogeneration applications with the "energy crisis" in California.

## X. Tours

The Solar assembly facility in Kearney Mesa will be toured. The Solar Mercury 4 MW unit is being demonstrated under the DOE/ATS program. The main units are the Centaur, Taurus, Mars, and Titan units are assemble at this plant. Leslie Witherspoon is organizing the tour. John Dilliot will lead the tour of University of California, San Diego which has a Solar Titan with a SCONOX system. The total unit is a cogeneration plant of about 30 MW. The plant will be starting up in the near future. California regulations limit the emissions of NO<sub>x</sub> to 50 ton/yr. Going above this limit would put the University into a major pollutor category as well as trigger Title V requirements. Under these conditions, SCONOX was cheaper than other alternatives.