The First 100 GW of SCR in the U.S. - What Have We Learned?

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ABSTRACT

Since 1998, SCR NO_x control has been installed on more than 100 GW of coal-fired capacity in the U.S. The design basis for these applications was experience from Japan, accumulated since 1978 mostly on coals with less than 1% sulfur content, and from Europe, accumulated since 1987 mostly on coals with less than 1.5% sulfur content.

The U.S. experience reveals several lessons not evident from prior observations. Among those most broadly witnessed are: (a) the significant role of large particle ash (LPA), (b) widespread use of static mixers to achieve high NO_x removal, (c) almost universal migration by suppliers to low SO_2 oxidation catalysts, (d) implementation of reagent-based SO_3 mitigation systems, and (e) frequent accumulation of ash within the reactor and required intermittent cleaning, particularly on PRB coal. Other trends less broadly adopted are the use of aqueous ammonia and urea for reagent and temporary reactor operation at low temperature to eliminate economizer bypass.

Each lesson imposes cost and operating consequences that can be either detrimental or beneficial. Specifically, LPA impacts can be significant, but a $300-500K investment in modeling and retrofitting LPA screens can be recovered in two years through lower catalyst cost.

Also, the relatively modest cost for static mixers – usually about $500K for acquisition and 1 in w.g. pressure drop – can add several percentage points to NO_x removal, proving significant near-term payback. Perhaps most significantly, the annual cost for reagent to mitigate SO_3 - depending on the specific process - can approach the annualized cost for catalyst supply.

These and other lessons from the continually-evolving U.S. experience are reviewed, and the cost and performance implications for a 500 MW plant quantified.

INTRODUCTION

Significant SCR capacity on coal-fired power plants has been installed in the U.S. since 1997, most in response to the 1995 NO_x SIP-Call. The timing of installation is shown in Figure 1, which presents the year of unit startup. Figure 1 suggests that by the end of 2005, the 100th GW of SCR-equipped capacity became operational.

**Figure 1**. Coal-Fired Capacity of SCR Retrofits, By Startup Year
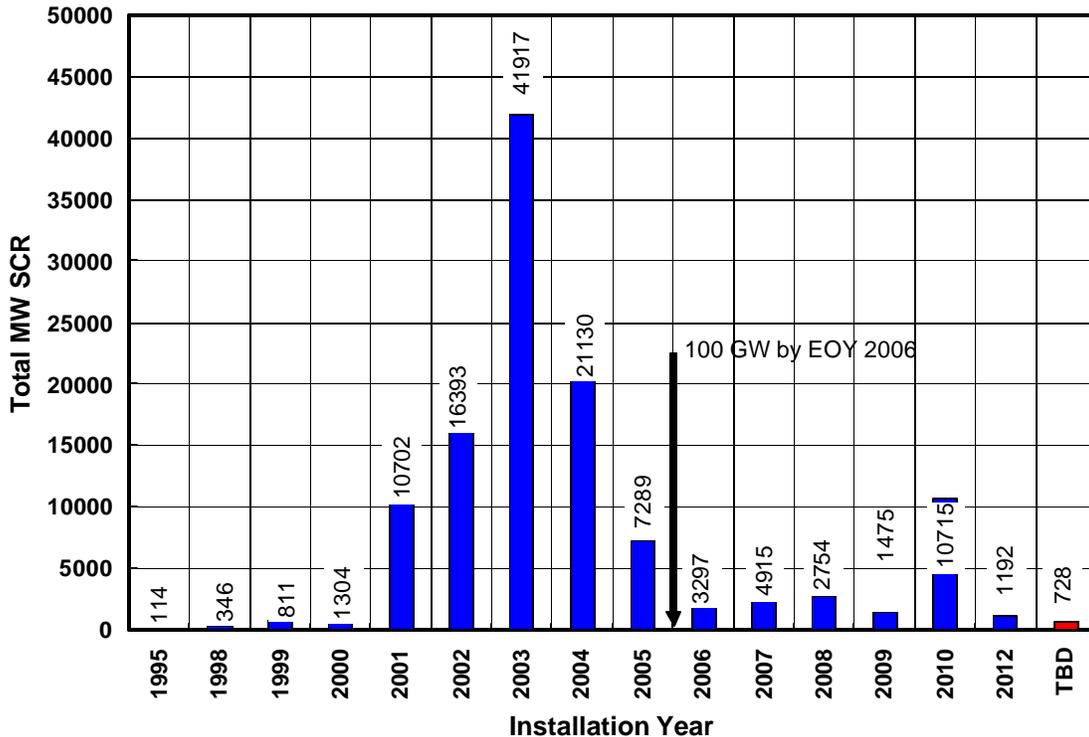
The inventory of SCR-equipped units will continue to grow – Figure 1 shows that between 2006 and 2012, approximately 20 GW of additional capacity are planned, predominantly to meet Phase I CAIR mandates. EPA and industry sources estimate an additional 10-20 GW of capacity will be installed by 2015, to meet Phase II CAIR mandates. The state-of-art of SCR that has evolved and is anticipated to be deployed differs from early U.S. applications. Key evolutions are summarized in this paper.

TECHNOLOGY EVOLUTION AND CATALYST PRICE

Catalyst technology has evolved significantly. The first-generation SCR applications in Japan targeted 50-70% NO_x removal, with residual NH_3 of 5 ppm, and generally did not specify a limit on SO_2 conversion. Development focused on catalyst longevity and performance, with early grid, plate, and pipe-type geometries offered. Development also focused on mechanical integrity, and simply avoiding erosion. As catalyst technology was relatively new, prices were initially high.

Figure 2 depicts the trend in catalyst prices cited in public literature. Figure 2 shows that catalyst prices – on the dollar basis of the year reported and thus not adjusted for escalation - have decreased from approximately $16,000/m^3$ to less than $4000/m^3$. Significantly, present-day demands on catalyst technology far exceed those from the early applications – NO_x removal of 90% is the usual design target, with control of residual NH_3 to 2 ppm, and SO_2 oxidation to usually less than 1%, and in many cases to less than 0.5%. Further, the catalyst substrate is desired to be able to withstand numerous one cleaning or regeneration procedure, and in some cases a guarantee for Hg oxidation.

Figure 2. Catalyst Unit Costs with Time
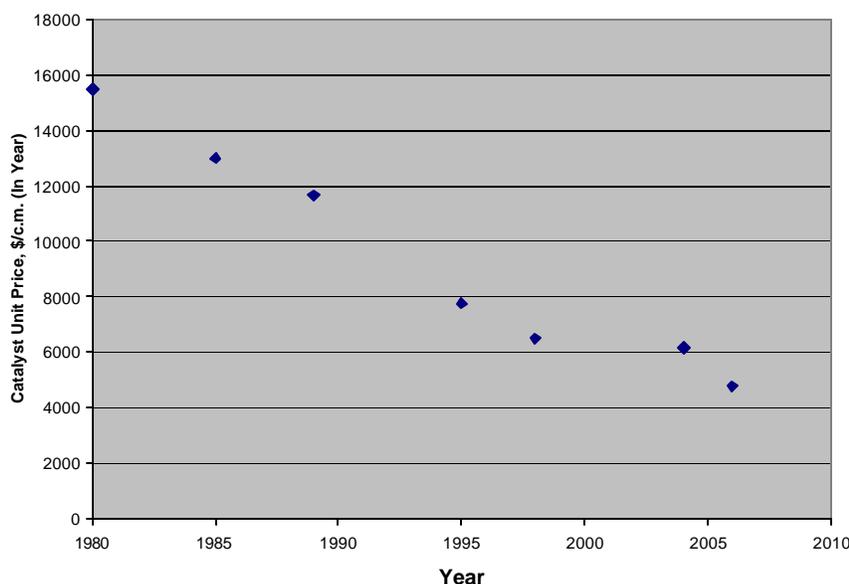
The simultaneous decrease in catalyst price and expansion in demand has provided a challenging environment for catalyst suppliers. At present prices of catalyst and ammonia feedstock (e.g. natural gas), the supply of catalyst is no longer the major contributor to SCR operating cost, and can be significantly less than reagent costs, or costs to mitigate SO_3.

REFERENCE CASE

A 2006 state-of-art SCR application for retrofit to an existing unit will exhibit a variety of performance-enhancing features, that incur either capital or operating cost (or both), but provide benefit. As background, it is instructive to consider the SCR cost components for a 500 MW

coal-fired unit, which provides a basis for comparing the cost impacts of factors unique to the U.S. experience, as well as remedial methods.

Table 1 summarizes the key SCR cost components for a 500 MW medium sulfur (2.6%%) bituminous coal-fired unit, operating at 85% capacity factor, with SCR operation initiating on an annual basis in January of 2007. The SCR process is designed for 88% NO_x removal from 0.40 lbs/MBtu, SO_2 oxidation of 1.5%, and employs a 3+1 reactor layout. Incurred costs for SCR are reported as net present value (NPV) basis, for a seven year period (through 2013).

Table 1. SCR Cost Components: 500 MW Reference Case, 7 Years Annual Operation

Cost Element	'07-13 NPV, $M	Comment
Catalyst Addition/Replacement	4.4	Based on $6200/m^3, four events from '07-13
Reagent Supply	8.6	Delivered reagent cost: $250/ton
Labor for Catalyst Replacement	0.064	
Flue Gas Fan Auxiliary Power	0.54	Aux power charge of $20/MWh

Note: Capacity factor 85%, catalyst cost $6,200/cubic meter, initial guarantee life of 16,000 hours, delivered reagent cost of $250/ton, power cost @ $20/MWh

Table 1 shows reagent supply comprises the largest component, followed by catalyst supply, flue gas fan auxiliary power, and labor for catalyst replacement. Key lessons from the 100 GW of experience in the U.S. will be cast in terms of impact on capital and operating cost, and compared to Table 1 results.

WHAT HAVE WE LEARNED?

The U.S. experience since 1995 has taught us:

- SCR capital cost has exceeded anticipated and projected values,
- NO_x removal performance, based on 5 month operation, is near design targets and generally supports compliance needs,
- LPA has emerged as a key issue; but remedial action is low cost and evolving,
- SO_2 oxidation is perhaps the most significant "unintended consequence", and imposes new constraints on design and additional significant operating cost,
- Uniformity of reagent mixing has evolved from 5-10% RMS basis, to consistently less than 5%, and in some cases 3-4%; to achieve these targets static mixers, if not essential, are the clear "technology of choice",
- Sonic horns provide a lower cost alternative to sootblowers; however cleaning problems may justify both,
- Urea is proven as feasible alternative to ammonia reagent, to simplify permitting obstacles and reduce (possibly misplaced) safety concerns, and
- Hg oxidation is evolving and could soon equate in importance to control of NO_x.

Each of these is considered in the following, including where possible a quantitative evaluation of costs.

CAPITAL COSTS HIGHER THAN PROJECTED

The capital cost of SCR has evolved with time, and significantly exceeds early estimates developed in the mid-1990s by EPA[1]. This escalation has been witnessed in spite of the considerable decrease in catalyst unit cost depicted in Figure 1. Three surveys have documented the increase in SCR capital cost[2, 3, 4]. The findings from these surveys are not directly comparable to each other, as all utilize a different unit population, and a reference year basis. Further, important factors such as the scope of equipment supply and construction labor rates have not been normalized. Regardless, Table 2 shows that initial cost projections by EPA of $55-90/kW, based on early and perhaps atypical applications and market conditions, were not realized. The reasons may never be known without a detailed autopsy of actual incurred project costs. It is likely the initial estimates were low due as (a) strong competitive forces, with 4-5 major suppliers competing for a limited number of projects, (b) relaxed performance target between 60 and 80% NO_x removal, demanding less equipment and engineering compared to present-day applications, and (c) degree of retrofit difficulty of the first sites, that although not simple did not reflect the design challenges of recent for SIP-Call units.

Table 2. SCR Capital Cost Survey Results

Reference	Average Capital, MW ($/kW)	Low-High Cost Observed ($/kW)	Observation
Hoskins, 2003	120 (400 MW)	80-160	Cost Basis: 2002. 15 of 20 reported unit costs exceeded $100/kW. Weak relationship of unit cost and scale.
Cichanowicz, 2004	81 (600-899 MW) to 123 (100-399 MW)	56-185	Cost Basis: 2003. For four categories of generating capacity, the least cost units were among the first installed.
Marano, 2006	118 (>900) to 167 (<300 MW)	Most costs reported to be within 100-200	Cost Basis: 2005. "Units with a capacity of 600 to 900 MW appear to be more difficult to retrofit than those in other size ranges."

The most significant observations from Table 2 are the paucity of units with reported costs < $100/kW, and lack of a correlation with generating capacity. With regard to the latter, Cichanowicz[3] shows capital cost actually can increase (per unit basis, or $/kW) at higher generating capacities. Similarly, Marano[4] concludes that units of 600-900 MW are more difficult to retrofit with SCR than other sizes. The challenge of large capacity retrofit is likely due to the increased complexity of the site. The case of Duke Energy's Belew's Creek Station, where the construction "laydown" area was one mile from the unit has been well documented[5]. Marano[4] notes the early SCR adopters incurred lower capital cost, with the year of 2003 recognized as a milestone after which costs increased significantly.

Lesson Learned. As SCR is deployed on an increasing fraction of generating capacity, the remaining host sites are becoming less amenable to retrofit. Compounding the increasing

complexity of site are greater demands on the process. The early SCR installations, in hindsight, may not have reflected to bulk of the U.S. boiler population.

NO$_X$ REMOVAL PERFORMANCE

If the cost of SCR has exceeded projections, then so has NO$_x$ control performance. NO$_x$ emission rate data available from the EPA Clean Air Markets website (www.epa.gov/airmarkets/emissions/raw/index.html) for 2005 shows that SCR equipment is for many units providing 90% NO$_x$ control, achieving low levels of outlet NO$_x$, and generally meeting industry's needs.

Figure 3 presents a plot of outlet NO$_x$ emission rate as reported to the EPA website, comparing data reported for the third quarter of 2004 and 2005. Notably, in 2004 approximately 28% of the units achieved a 5 month average of 0.06 lbs/MBtu, or less; the fraction of units achieving this outlet rate increased to 42% in 2005.

Figure 3. NO$_x$ Outlet Emissions in 3Q: 2004 vs. 2005
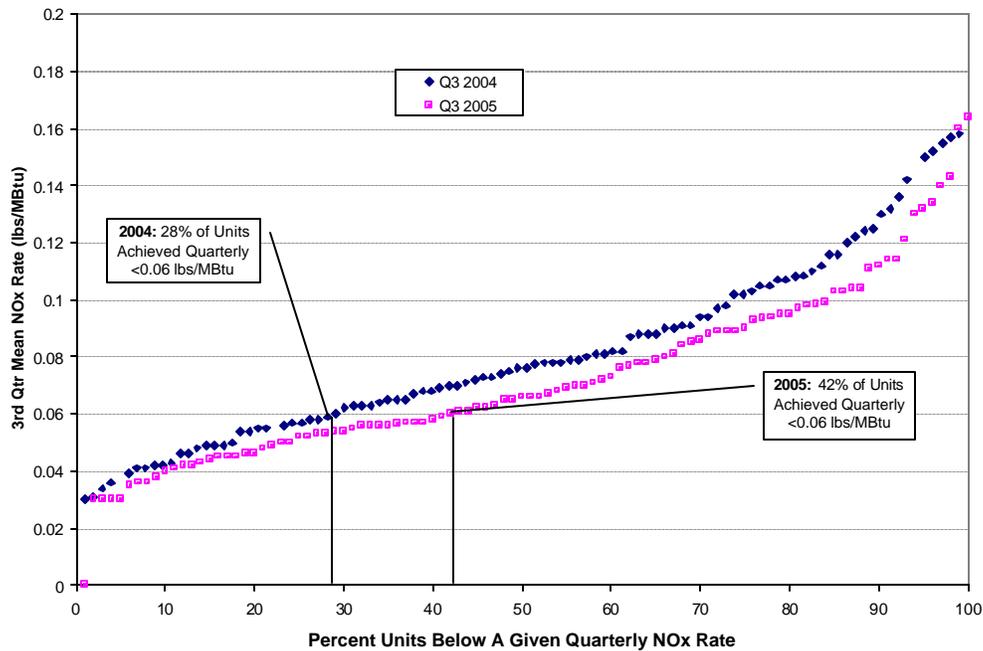
How were these reductions in 2005 achieved? Examining the hourly NO$_x$ data is revealing. Figure 4 shows the cumulative distribution of NO$_x$ data as measured in 2004 and 2005 for a medium high sulfur coal-fired unit. Figure 4 is prepared by ordering the entire population of data from lowest to highest NO$_x$ emission rate, and plotting this rate as a fraction of the total population. Compared to data in 2004, the data in 2005 is distinguished by a relatively small population above 0.20 lbs/MBtu. The essence of Figure 4 can be captured by noting the NO$_x$ emission rates that typify the 5% and 95% population – that is, NO$_x$ emissions at which 5% and 95% of the data are below. Figure 4 shows that in 2004, 5% of the operating time NO$_x$ exceeded 0.20 lbs/MBtu – suggesting either partial or compromised performance of instrumentation and

control systems, reagent feed system, partial blockage of catalyst, inadequate distribution of NH_3, or any other reason. These issues were corrected in 2005.

**Figure 4**. Cumulative Distribution of NO_x Emission Rates: 2004 vs. 2005
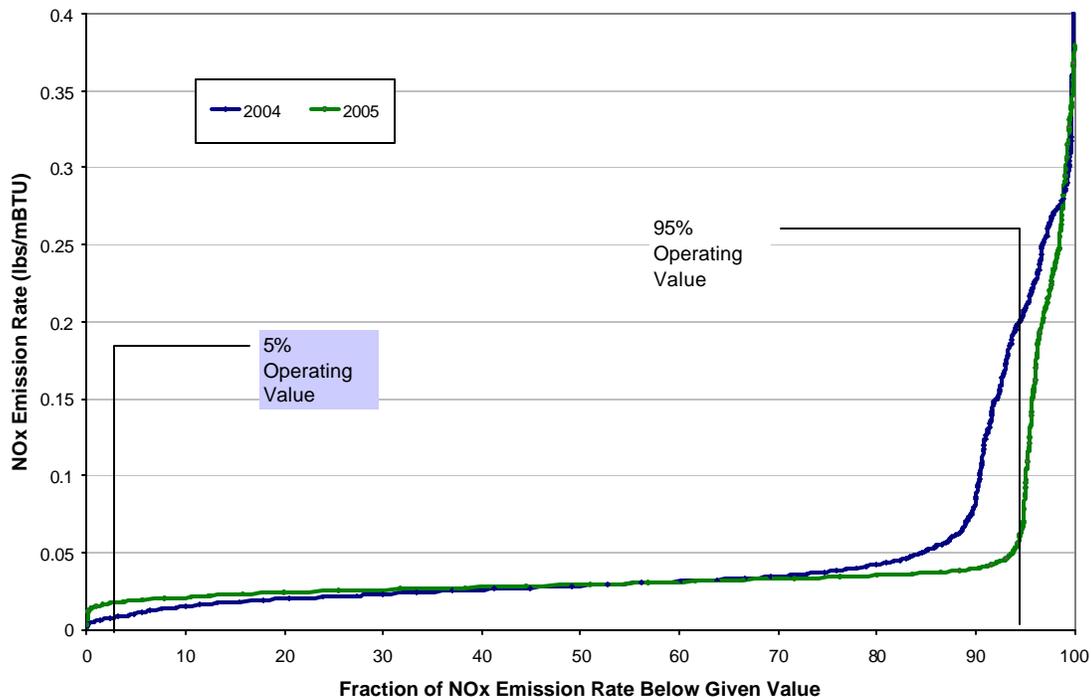
Comparing the 5% and 95% NO_x emission rates for several units shows that eliminating the data population with high NO_x is usually responsible for achieving low NO_x for an ozone season. Figure 5 compares 2004 versus 2005 NO_x data for 6 units, showing the mean values and those characterizing 5% and 95% of the data. Four of these units reduced ozone season NO_x in 2005 by eliminating many of the incidents of high (e.g. 95%) NO_x emissions. One unit incurred higher 2005 seasonal NO_x as the data population with high NO_x increased. Figure 5 suggests that process upsets and equipment malfunctions are being eliminated as experience increases, resulting in lower seasonal NO_x values.

Of the 101 units reporting to the EPA website with single stack data, most exhibited a decrease in NO_x in 2005, when comparing third quarter data with 2004. Specifically, 52 units reported lower NO_x, while 28 were unchanged and 21were higher.

Lesson Learned. A significant number of SCR equipped units – over 40% - can achieve on a seasonal basis a NO_x emission rate of 0.06 lbs/MBtu, or less. SCR NO_x outlet levels have been reduced in 2005 by improving equipment reliability so that the fraction of data incurring high NO_x "peaks" is reduced.

Figure 5. Mean, 5%, and 95% Percentile Emission Rates: 2004 vs. 2005
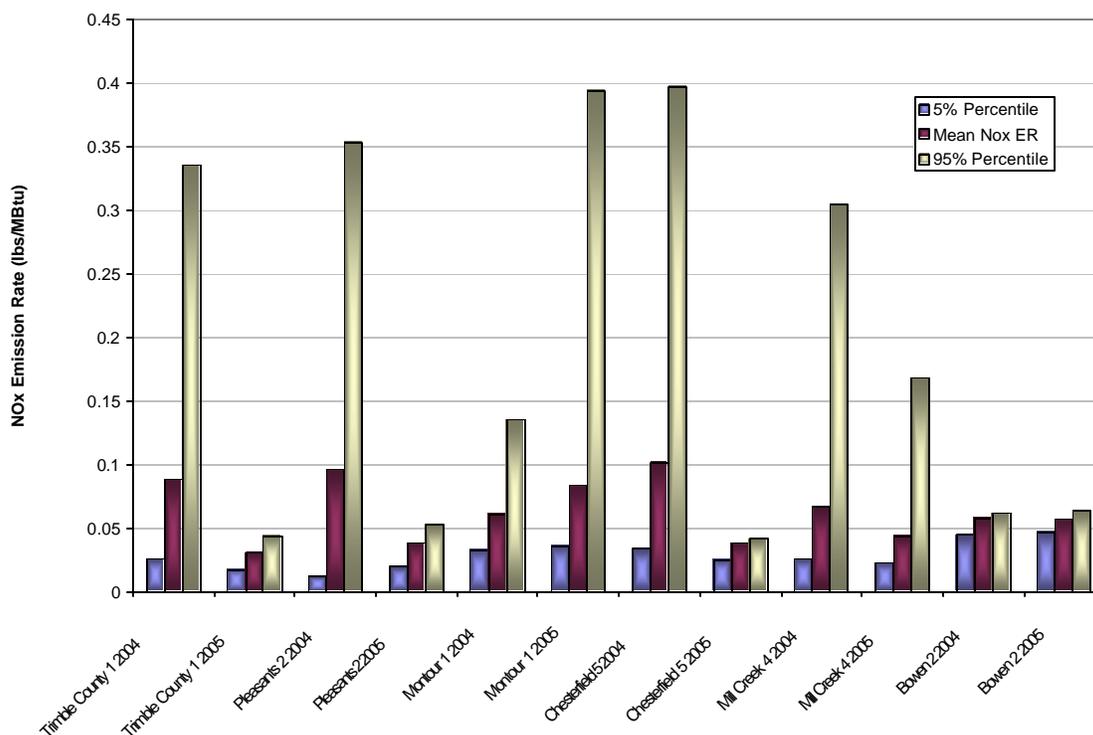
THE GENERATION AND ROLE OF LARGE PARTICLE ASH (LPA)

Perhaps the most significant and unprecedented phenomena experienced in the U.S. is the generation and accumulation on catalyst surfaces of large particle ash (LPA) – historically referred to as "popcorn ash". In general, LPA is defined as particles that are 4-7 mm in characteristic dimension, of adequate dimension to lodge within the openings of grid- or plate-type catalysts. LPA asserts an impact on catalyst performance that is separate and distinguishable from conventional fly ash.

The genesis of LPA is not clear – most perplexing was the infrequent observation of LPA in early SCR applications in Germany, where the rare occurrence was viewed atypical. It is also unclear why U.S. SCR applications have been so prone to LPA-induced reliability problems. Several reasons have been speculated: the composition of coal that is fired, degree of combustion staging and low NO_x firing conditions, and the physical geometry of the furnace and convective section. Ryan[6] speculated that LPA was generated from the convective section, and further that 100% capture of particles 5 mm and greater would be necessary to protect the integrity of a conventional 7 mm pitch catalyst. It is interesting to note that most SCR applications in Germany have been on tower design boilers, in which the convective section is located directly above the radiant zone. If LPA is generated as a consequence of sootblowing furnace walls and the subsequent fragmentation of deposits, the geometry of the tower design boiler may provide a barrier to penetration of LPA particles to the SCR reactor. In U.S. applications, where the Carolina-type boiler geometry is predominant, there is a smaller physical barrier between the convective section and the reactor. Further, some observers have noted

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minor accumulation of LPA within air heater prior to SCR retrofit, only to experience significance LPA plugging after SCR retrofit. It is possible the change in ductwork preceding the SCR reactor – and possibly the loss of the economizer hopper and increase in flue gas velocities at the economizer exit – are responsible for a higher degree of LPA reporting to the SCR reactor.

Several mitigation methods exist and have been summarized by Ryan[7] and Gretta[8]. First, frequently evacuating the economizer ash hoppers and implementing minor modifications to encourage LPA capture and minimize re-entrainment are the least cost options. Next, installing screens and baffles to deflect LPA to the economizer hoppers encourages LPA removal. Expanding ductwork to slow flue gas velocity, and increasing hopper slope angles to retain more LPA is effective but can require significant ductwork modifications. The screens and baffles can be rigid and fixed as described by Ryan[7], or flexible as described by Gretta[8]. Designs can be modularized allowing replacement of screens, which may erode in high velocity areas. One screen design employs a robust, erosion-tolerant, self-cleaning design that, depending on space available and capital cost, may be appropriate[9]. Screen material can be uncoated if ductwork velocities are consistently less than 40 aft/s, but may require flame-spray coating if velocities exceed 60 aft/s. McLaughlin[10] recommends that economizer hoppers be enlarged as part of any SCR retrofit, particularly if baffles or screens are employed. These mitigation methods are offered by individual suppliers or boiler manufacturers, for both new and existing applications. Finally, the design of ductwork routing flue gas to the SCR reactor should be maintained at modest levels, generally not exceeding 40-45 aft/s, to encourage particle drop-out.

LPA remedies provide cost-effective means to prevent premature deterioration of SCR performance. Table 4 summarizes the cost impact of LPA mitigation methods and benefits for the reference 500 MW unit. The capital cost for a simple rigid screen can require from $200K up to $500 K installed, for an erosion-tolerant design to accommodate high flue velocities, and include exotic material of construction. Operating costs can be 1 in w.g. pressure drop, and an additional $150 K every 2 years to replace eroded screen panels.

For the reference plant in Table 1, the 7 year NPV for these costs elements is approximately $1.1 M, which can be recovered over any of three scenarios. First, this $1.1 M cost can be recovered by avoiding a single outage, or accelerating an outage, to clean catalyst. Alternatively, as shown in Table 3, simply providing for an increase in open area by 10 percentage points – e.g., reducing plugging so that a reactor 80% open (20 % plugged) can be 90% open (10% plugged) - provides at least 2% additional NO_x removal at the same residual NH_3 limit. The NPV of the additional NO_x removed over the 7 year period significantly exceeds the cost of adding screens. Alternatively, the LPA remedy prevents catalyst replacement rate from being accelerated to meet the same performance targets – maintaining the open reactor area by an additional 10 % will avoid the purchase of one more layer of catalyst over the seven year period. The NPV of these actions is reported in Table 3.

LPA Lesson Learned. For a variety of reasons stemming from coal properties, low NO_x firing conditions, or boiler design, U.S. SCR-equipped units have been prone to LPA. Experience to date suggests perhaps 1 in 4 or 1 in 5 units are susceptible to some impact. LPA mitigation methods that are state-of-art require modest cost, and provide significant benefit.

Table 3. LPA Mitigation Cost, Benefits: 7 Year NPV Basis

Item	Capital Cost (EOY 2006)	Other Fixed Charges	Annual Cost ($000)	LPA NPV ($M)	Benefit/NPV
LPA Mitigation	500	$150K screen replacement at 24 months	60	1.1	Consistently achieve additional 2% NO_x removal over 7 years. NPV: $13.5
					Prevents need for 5 catalyst events over 7 year period, saving $1.5 M

SO$_2$ Oxidation

The ability of SCR catalyst to oxidize a portion of SO_2 to SO_3 has been recognized as a potential issue since early designs, derived from experience on lower sulfur coals in Japan and Germany, were adapted to higher sulfur environment in the U.S.[11]. In the early 1990s, in Germany there were several occasions of SCR-induced sulfuric acid particle generation and drop-out[12]. Catalyst suppliers recognized the need to mitigate SO_2 conversion, and began development of lower SO_2 conversion designs; however not all procurement specifications in the evolving U.S market called for SO_2 oxidation below 1.5%. Many industry participants envisioned that specifying low SO_2 oxidation catalyst would place a product at a competitive disadvantage, as historically low SO_2 conversion catalyst has required for some suppliers 20-30% greater volume to achieve the same level of NO_x and residual NH_3 control.

Controlling SO_2 became of paramount importance after the first broadly witnessed SO_3 plume[13]. Subsequent to this milestone event in 2001, controlling SO_2 oxidation has evolved to be of equal significance in SCR design as NO_x control. This is due to additional SO_3 control requirements that have been imposed, as SO_3 plumes have come under scrutiny of local regulators. In response, some local jurisdictions have implemented SO_3 limits of 5 ppm or less, significantly lower than the pre-SCR value. As of this writing, at least six states are known to be contemplating SO_3 limits on power stations, triggered by the implementation of SCR.

Consequently, all catalyst suppliers have further explored low SO_2 designs. With capabilities of different catalyst for NO_x and residual NH_3 becoming similar, SO_2 oxidation can be a key deciding point for replacement or initial inventory catalyst. At least one eastern bituminous coal-fired unit of greater than 1000 MW capacity has replaced one layer of the initial inventory of catalyst with a low SO_2 oxidation variety; and further the authors have advised several catalyst decisions where the deciding factor has been SO_2 oxidation, not control of NO_x. The only downside is that depending on the catalyst supplier, low SO_2 oxidation designs can require greater catalyst volume to meet the same NO_x removal and residual NH_3 performance. This trend does not reflect all suppliers, and evolving technology may provide alternatives[14], but recent procurement actions suggest this trend is valid at present.

A key impetus to minimize the SO_2 oxidation is to reduce the relatively high operating cost for reagent-based SO_3 mitigation methods. Dombrowski[15] has shown that reagent costs alone to lower SO_3 from 40 to 3 ppm can range from $1.2-1.5 M annually, for any of the sodium, magnesium, or calcium-based sorbents. This cost rivals that for annual SCR reagent supply and can exceed catalyst replacement charges.

Table 4 summarizes the cost impact of specifying low SO_2 conversion catalyst. For the reference unit in Table 1, it is assumed a low SO_2 conversion catalyst of 0.3% is available but requires 20% more catalyst to achieve the same degree of NO_x control as the "baseline" 1.5% SO_2 oxidation catalyst. As a consequence the SO_3 exiting the SCR reactor is reduced from approximately 45 to 23 ppm (at 3% O_2). If the unit is required to meet a strict SO_3 limit of < 5 ppm and uses any of the reagent-based methods, the lower SO_3 generated translates into a reduction in reagent consumption.

Table 4. Cost Summary: Low SO_2 Catalyst and SO_3 Remediation

Case	Initial Catalyst Volume (m^3)	Catalyst Layers Purchased In 7 Years	7 Year NPV Cost ($M, NPV)	SO_3 Reduction Cost ($M, NPV)
Baseline	3 layers at 220 each	4	4.4	N/A
Low SO_2 (0.35% oxidation) Case	3 layers at 264 each	4	5.3	1.3
Low SO_2 (0.35% oxidation) Case	3 layers at 220 each	6	6.7	2.3

Depending on reactor and catalyst layer design, higher cost can be incurred in two modes, which are shown in Table 4. If the catalyst layer height can be expanded from the initial design, higher costs will be incurred for a 20% greater initial inventory, and commensurately larger addition or replacement layers. Alternatively, if the catalyst layer height cannot be increased, the catalyst replacement rate will be increased to compensate for the lower activity (with respect to NO_x) catalyst.

Table 4 shows that compared to the baseline case, catalyst costs (7 year NPV) can be $1.3M greater if an enlarged quantity of initial and replacement catalyst is used to achieve the same NO_x reduction/residual NH_3 target. Alternatively, if reactor design limits the catalyst volume in each layer, more frequent catalyst changeout is required and a 7 year NPV of $6.7M may be incurred, representing an increase by $2.3M.

Any additional costs for lower SO_2 oxidation catalyst are either fully or partially compensated for by lower operating costs for reagent-based SO_3 mitigation. As shown in Table 5, reagent cost to provide 80-90% SO_3 removal can be reduced for the reference case between $155,000 to $440,000 annually. These costs equate to a 7 year NPV of almost $1M to $2.7M, and may not completely offset the higher catalyst management costs. However, lower SO_3 provides benefits beyond the scope of this paper.

Table 5. Reduction in SO_3 Mitigation Cost Due To Lower SO_2 Oxidation Catalyst

Reagent	Delivered Cost ($/ton)	Stoichiometric Ratio (X/SO_3)	Reduction in Annual Cost (~80-90% Removal)	7 Year Cost ($M, NPV)
Hydrated Lime	100	3/1	285,000	1.7
Trona	125	2/1	155,000	0.95
$NaHSO_3$	250	1.2	440,000	2.7

<u>Lesson Learned</u>. Specification of SO_2 oxidation – to 0.75% and possibly to as low as 0.30 % - for replacement or for new catalyst inventory is evolving to be of equal importance to control of NO_x and residual NH_3. The use of extremely low SO_2 oxidation catalyst can – depending on the supplier –increase catalyst volume and alter management strategy. Higher catalyst management costs can be partially or completely offset by reduced reagent for SO_3 mitigation.

REAGENT MIXING

The ability of to mix NH_3 with NO is perhaps the most important factor in determining – and maintaining – high NO_x removal and low outlet NO_x emissions. Criteria for NH_3/NO uniformity for present-day SCR design of 90% NO_x removal and 2 ppm residual NH_3 is specified to be less than 5%, where the degree of uniformity is based on a RMS or coefficient of variation basis.

Reagent mixing technology has evolved significantly from the first SCR applications, which were based on the design criteria in Europe to control of NO_x to a nominal 100 ppm per unit, and required on average 80-85% NO_x reduction. This level of control was usually achieved with a grid-type array of injectors, with occasional use of static mixers. The early grid-type injectors at the time could feature over 1000 individual injection nozzles on one unit – offering flexibility in NH_3 control, but potential maintenance issues. One of the early SCR installations in the U.S. – the Orlando Utilities Commission Stanton Unit 3 – featured static mixers. In general, an SCR specification for NH_3/NO ratio in the mid 1990s might require 5-7% NH_3/NO, but recent needs are evolving to be less than 5% and in some cases 3-4%.

At present, most SCR installations will employ some type of static mixer to achieve this level of NH_3/NO mixing. There are several options by which to acquire static mixer technology - some proprietary to a process or boiler supplier, with others available for unrestricted use. Three boiler suppliers offer an exclusive technology: Babcock-Power offering the delta-wing, Siemens both the Parmix and Turbomix designs, and Babcock & Wilcox developing a proprietary design, in addition to their "bat-wing" particle knock out device. Individual suppliers such as Koch and Sulzer offer static mixers for any boiler or SCR process application. Significantly, static mixers provide a more uniform flux of NO_x, temperature, and induce mixing of NH_3 and NO with a simple system. Although static mixer use is prevalent, it is not a requirement for success – several installations such as the AES Somerset and First Energy's Mansfield station have achieved at or near 90% NO_x removal with conventional grid-type systems.

Figure 5 depicts the degree of NH_3/NO uniformity achieved after tuning the ammonia injection grid (AIG) on numerous SCR reactors, and considering six different reagent injection schemes,

Figure 5. NH$_3$/NO Uniformity (RMS Basis): Various Reagent Injection Schemes
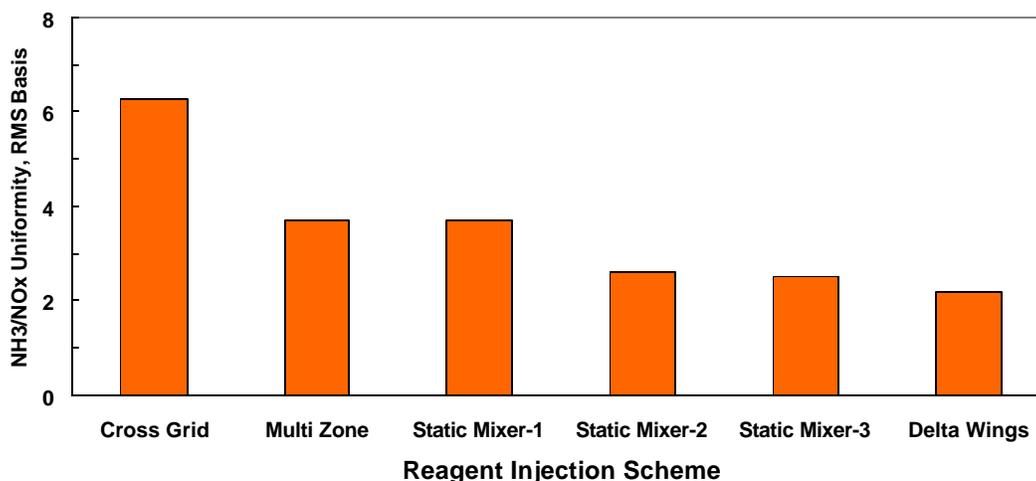
including four different static mixer designs. Figure 5 suggests static mixers of any design will improve NH$_3$/NO uniformity compared to multiple injectors alone.

The cost of installed static mixers will vary – units with reactor inlet ductwork well above grade can incur major structural costs to support the additional mass. As an example, a 500 MW unit may incur an installed capital cost of $750K, and induce an additional 1 in w.g. of flue gas pressure drop. The 7 year NPV cost incurred for this mixing system can be $1.05M.

Equally important to achieving good NH$_3$/NO uniformity is retaining it. Figure 6 compares the NH$_3$/NO ratio for eight SCR reactors, comparing the (a) as-found state, after at least one year of operation after startup, and (b) immediately after tuning. Figure 6 suggests that an investment in annual tuning – $30K-$50K depending on the unit size – can consistently reduce NH$_3$/NO unmixedness by 2-5%, RMS basis.

The benefit of employing static mixers and frequent tuning to reduce unmixedness in NH$_3$/NO can be quantified. For the hypothetical plant reported in Table 1, reducing the NH$_3$/NO ratio from 7 to 3% RMS basis can either increase NO$_x$ removal at the same residual NH$_3$, or extend catalyst life at the same NO$_x$ removal. Table 6 summarizes the benefits of the latter, showing that maintaining the lower NH$_3$/NO ratio can eliminate one layer of catalyst purchased over a seven year period, saving $1.1 M. Even after accounting for the $0.17 M NPV cost for outsourced tuning ($50 K at 18 month internals), significant savings are derived.

Lesson Learned. The requirement to achieve 90% NO$_x$ removal and 2 ppm residual NH$_3$ requires NH$_3$/NO uniformity significantly less than 5%, and perhaps to 3%, as measured on a RMS basis. There is no guarantee that this degree of unmixedness can be achieved, or attained consistently after startup. Static mixers, although perhaps not essential to meet these strict requirements, enables achieving these levels. Annual tuning of the AIG can also help maintain NH$_3$/NO$_x$ uniformity and reduce operating costs.
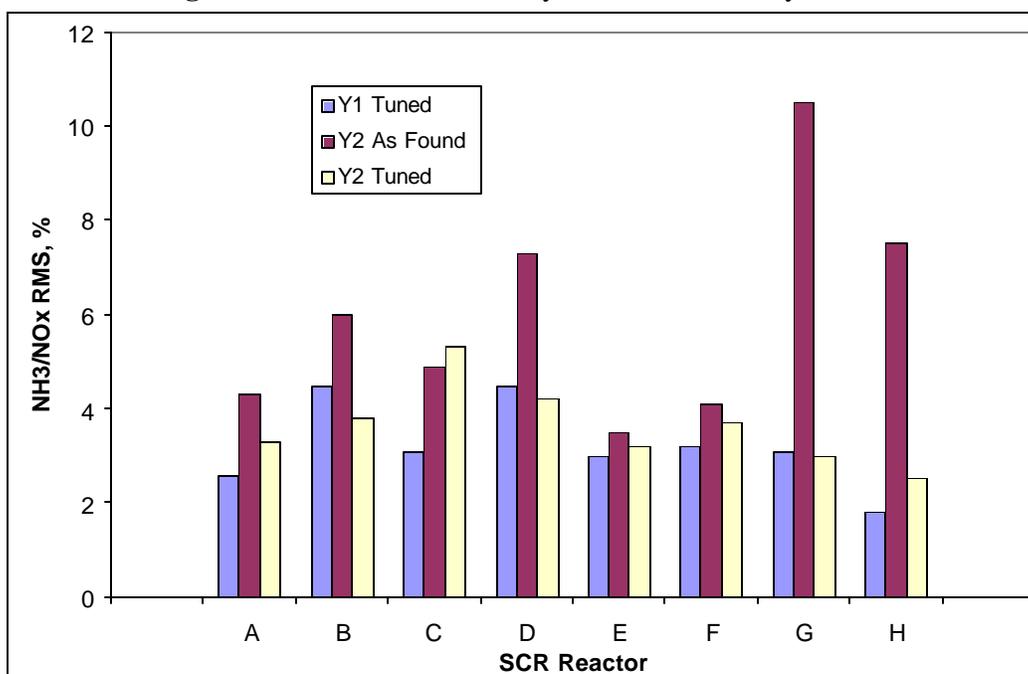
Figure 6. NH$_3$/NO Uniformity: As-Found, Newly Tuned

Table 6. Catalyst Savings Due to Improved NH$_3$/NO Uniformity (90% Design Target)

Case	Initial Catalyst Volume	NH$_3$/NO Uniformity (% RMS)	Catalyst Layers Purchased In 7 Years	7 Year Cost ($M, NPV)
Baseline	3 layers at 220 m^3 each	3	4	4.4
As-Found	Same	7	5	5.5

Catalyst Cleaning: Sonic Horns

The use of sonic horns in maintaining a clean catalyst has progressed in 10 years from experimental to a standard design practice. In 1998, a fact-finding trip by EPRI to SCR-equipped units in Europe identified only several units experimenting with sonic horns, some exploring side-by-side trials with sootblowers. In the U.S., as recently as 1999, few units featured sonic horns – the first reportedly tried in the U.S. at Orlando Utilities Commission Stanton Unit 3. The use of sonic horns in the U.S. has risen steadily to where approximately half of the new retrofit or new units are designed to include sonic horns; one supplier claims installation on 100 reactors

Sonic horns are reported to not remove ash deposits but prevent accumulation on catalyst surfaces. Early European and U.S. experience suggested sonic horns maintained catalyst as clean as sootblowers, but for less capital and operating cost. Also of importance, sonic horns are reported to require less preventative maintenance, and cannot damage catalyst through either high pressure operation, or through steam leaks.

Sonic horn capital cost can be 25% of that required for steam sootblowers, thus a single layer of catalyst can be equipped with sonic horns for $40,000-100,000 depending on the size of the unit. In comparison, traveling-rake steam sootblowers can require an installed cost of $120,000-160,000. Operating cost savings can be significant – one supplier reports that the auxiliary power to operate two sonic horns at the conventional frequency (10 seconds every 10 minutes) equates to about $1 per day. The cost for operating steam sootblowers depends on the quantity of steam required, and how that steam is valued – as either a heat rate penalty, or a capacity penalty, or both. At the 250 MW Birchwood Generating Facility in Virginia, where both cleaning modes were compared side-by-side, operators report maintaining the 1.5 layers of catalyst clean with sonic horns requires a daily operating cost of less than $4/day, compared to approximately $41/day for conventional sootblowers. For the 500 MW reference unit equipped with a 3+1 SCR reactor design, the total investment for sonic horns including installation could approximate $275K, with $5K required annually for power. Travel-raking sootblowers could require $550K, with $20K required annually in the value of steam consumed. Based on these assumptions, sonic horns provide a saving on a 7 year NPV basis of $375K ($305K for sonic horns vs. $680K for sootblowers). In the present-day competitive utility market, these savings cannot be ignored – as long as equivalent cleaning is provided.

In terms of operation, traveling rake sootblowers can require significant maintenance, and damage the catalyst if steam leaks and condenses on the catalyst surface, or excessive cleaning pressure if used above recommended values. For sonic horns, the intrusion of moisture and fly ash, particularly PRB ash, into the horn casing can plug the horn and compromise operation. Condensation of moisture that penetrates the housing and enters the horn is promoted by the expanding compressed air that drives the horn and lowers temperatures. Several PRB-fired units have encountered this problem. Insulating the portion of the horn outside of the reactor has helped mitigate this issue.

This favorable summary of experience and cost for sonic horns should not be construed as an endorsement - maintaining the catalyst clean and open to flue gas flow is critically important, and even a slight advantage to sootblowers will justify their use. The demands for high SCR NO_x removal performance requires extremely clean catalyst. The higher cost for sootblowers can be justified in many applications. At least two PRB-fired units have retrofit sootblowers to augment or replace sonic horns in maintaining clean catalyst with PRB coal. As shown by the example for LPA in maintaining a clean surface, increasing the catalyst open surface area derives significant cost benefit that outweighs the additional cost for sootblowers.

Lesson Learned. Sonic horns have evolved to provide a lower capital and operating cost alternative to steam sootblowers. However, the value in providing extremely clean surfaces is so great that the best cleaning system should be used regardless of cost. Experience is the best guide.

REAGENT SUPPLY BY UREA

With the potential hazards associated with anhydrous ammonia, local communities have frequently demanded that utilities find alternate reagents; specifically aqueous ammonia and urea-based systems. By using urea, utilities 1) simplify the permitting process, 2) avoids a risk

management program, 3) mitigate potential hazards shipping ammonia to the site, and 4) mitigate hazard during storage and handling at the site. These advantages require higher process capital, additional energy to convert urea to ammonia, and a more complex reagent handling system to operate; however they can be offset by indirect costs in terms of staff in developing risk management and safety training.

Four systems are sold commercially in the U.S. to convert urea to ammonia for use with SCR systems. Two of these systems hydrolyze an aqueous urea solution, one melts solid urea and reacts the melted urea over a catalyst, and the fourth decomposes an aqueous urea solution by spraying it into a hot air stream. Each is described briefly below:

U2A™ was developed under an EPA Small Business Innovative Research (SBIR) award to EC&C Technologies, and is based on the hydrolysis of an aqueous solution of urea and/or biuret by heating under pressure to form a mixture of ammonia, carbon dioxide, and water. The patent awarded was licensed to Wahlco and Hamon Research-Cottrell.

AOD™ also hydrolyzes a urea solution to form gas phase ammonia and carbon dioxide. The process was exclusively licensed to Environmental Elements Corp. (EEC) from Hera, LLC and Siirtec Nigi. In December 2000, EEC announced that it executed an agreement with American Electric Power Company to provide additional support for the commercialization of AOD™ technology in the power generation market. The agreement also grants AEP an exclusive sub-license to market and sell urea-to ammonia systems.

NO$_x$OUT ULTRA™ has been developed by Fuel Tech NV and involves the atomization of a urea solution within a decomposition chamber containing an air or flue gas stream between 800 – 1200°F The urea dissociates at these temperatures to ammonia and isocyanic acid (NHCO), whereupon the vapor stream is introduced into the flue gas ahead of a SCR through an injection grid.

The SafeDeNO$_x$™ process involves melting urea and mixing the liquor with steam, where it reacts across a catalyst to form ammonia, carbon dioxide, and water vapor. Chemithon is the sole implementer of this process.

Although several startup problems and operating issues were encountered on the first units, in time a reliable system evolved that does not limit the reliability of the SCR process or the power station. Of note is that safety concerns by local communities are evolving, and even for existing SCR equipped units, pressure to adopt urea may exist. Significantly, the Brandon Shores station – one of the first SCR-equipped units in the U.S. – has employed all three forms of reagent supply, due to evolving demands of the local community.

Each of the reagent options - anhydrous ammonia, aqueous ammonia, and urea - will feature a different capital and operating cost. The capital cost of these systems can vary with design, and a comparison is beyond the scope of the present paper. In addition to the capital cost of the reagent supply system, and reagent procurement cost, the energy required to vaporize, or decompose, the reagent is also an important factor.

Table 7 summarizes the key cost components that can influence reagent operating cost. Also shown is an approximate delivered reagent cost; the latter is highly site specific and will vary with delivery distance and volume of material purchased. Table 7 shows that anhydrous reagent is usually the least cost; however local communities may assert their preference for alternative reagents regardless of cost. Further, when considering the demands on management and staffing for safety, planning, and training, anhydrous reagent may not be the least cost.

Table 7. Comparison of Key Reagent Operating Cost Variables

| Reagent	Energy For Vaporization (Btu/lb)	Cost for Vaporization ($/year)	Delivered Reagent Price ($/Ton-NH$_3$/Urea)	NPV For Reference Unit ($M)
Anhydrous	588	$16,000	$225	3.75
Aqueous Ammonia, 29%	2683	$72,600	$250	4.45
Aqueous Ammonia, 19.5%	4312	$116,700	$400	6.82
Urea	3500	$167,200	$300	8.94

Lesson Learned. Local communities have been successful in asserting an influence in reagent selection. Both anhydrous and urea-based reagent supply systems offer state of art and reliable alternatives to anhydrous forms of ammonia. Despite the excellent safety record with anhydrous ammonia to date, pressure to utilize alternatives will persist.

MERCURY OXIDATION

Interest in mercury (Hg) oxidation in the last few years has escalated, with recognition that the combination of SCR and wet FGD can provide some degree of Hg removal. Critical to the amount of so-called Hg "co-benefits" is (a) the degree of Hg oxidation by the SCR, and the ability to retain this oxidation with time, (b) sensitivity to fuel composition, including subtle changes in coal chloride content, and (b) eliminating the Hg re-emission by wet flue gas desulfurization (FGD). Given the importance and cost impact of Hg control, it is possible the so-called "co-benefits" will supercede in importance SO$_2$ conversion for some fuels.

Following early tests in Germany, the first orchestrated attempts to determine the oxidation of Hg by SCR were conducted as part of the EPA ICR program. These early results prompted measurements to date on about 20 individual units, sponsored collectively by EPRI, the Department of Energy, and the EPA. Chu[16] has summarized the degree of Hg oxidation by SCR for 15 different units, and the results in Figure 7 suggest a weak correlation with coal chloride content. Data in Figure 7 are not directly comparable – almost all data points represent a different SCR design, catalyst composition, and operating history. The ability to predict Hg oxidation is the subject of study by almost all catalyst suppliers as well as independent providers of process models[17, 18].

Figure 7. Hg Oxidized by SCR Process Equipment: Field Tests (after Chu, 2006)
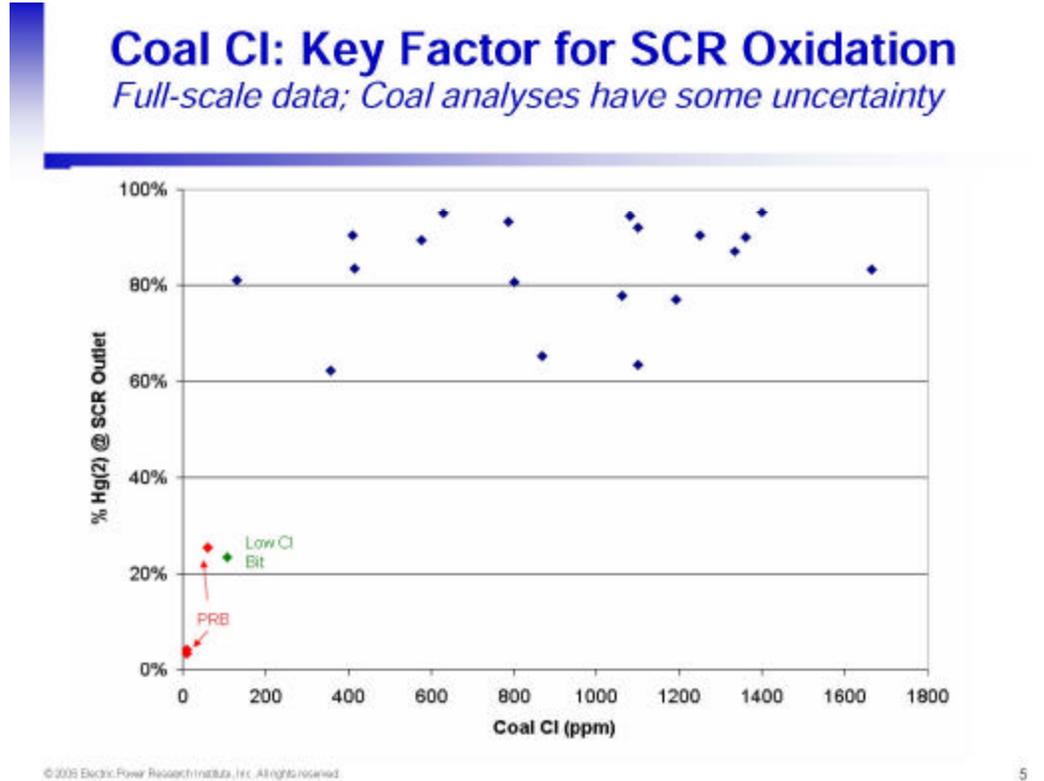
Each of major SCR catalyst suppliers is addressing the prospect of offering Hg oxidation guarantees. Discussions with these suppliers suggest it is not clear if there is a link between the oxidation of SO_2 and Hg. At least one supplier reports any link between Hg and SO_2 oxidation is weak, and high Hg oxidation catalysts may not necessarily promote SO_2 oxidation; however not all suppliers agree with this position. Further complicating the analysis is accuracy of Hg measurements, which are highly variable, and may not provide the basis for guarantee provisions.

Additional experience and field tests in the next years will provide key information. Two catalyst suppliers at present will provide guarantees for Hg oxidation, depending on coal composition and system design. However, owners must consider the value of the guarantee and the difficulty of Hg measurement – so much so that a dispute may not be satisfactorily resolved. First, some agreement on Hg measurement should be pursued – should it be in commercial systems where uncertainty may be high, or in a laboratory environment with simulated flue gas with well controlled conditions? Also, owners should examine the significance of the guarantee – as is the case with an evolving technology, the protection offered to the owner may not be significant in terms of liquidated damages or the value of a replacement catalyst layer.

The importance of Hg controls and their cost will elevate Hg oxidation to a major decision factor in purchasing replacement or new catalyst inventory. For the 500 MW reference unit, if the reference coal fired contained 400 ppm chlorides, then Figure 7 suggests Hg oxidation could vary between 60 and 90 %. The cost significance of providing a guarantee for the higher value

(90%) compared to simply deriving the average of 75% is significant. For the reference unit, assuming an Hg coal content of 7 lbs/TBtu, providing for the higher guaranteed level of 90% oxidation increases the production of oxidized Hg (and decreases the production of elemental Hg) by 40 lbs per year. Assuming 95% of this oxidized Hg is collected and not re-emitted by the FGD, and Hg removal allowances are valued at the minimum of DOE's research goal of $25,000/lb, the 90% Hg guarantee translates into an annual benefit of $0.90 M. The NPV 7 year value of acquiring these Hg reductions is $5.5M, rivaling the significance of any other SCR operating cost reported in Table 1. Accordingly, Hg control issues may dominate SCR catalyst design and selection.

Lesson Learned. Depending on coal composition and SCR design, some degree of Hg oxidation is provided by SCR. The extent and longevity of the effect of SCR is not clear – it is possible the degree of oxidation will decrease with time at a rate equal to or greater than for NO_x. Hg control may drive future catalyst design and selection decisions.

FURTHER OBSERVATIONS

Several additional observations, although not necessarily comprising a "lesson learned", are noteworthy. These items are either unresolved, have not projected a consistent trend, or represent concepts for which our understanding is incomplete.

Catalyst Plugging with PRB

PRB-fired SCR units have been prone to excessive plugging by fly ash – without LPA. Several units have experienced nearly complete blocking of turning vanes and catalyst layers, in some cases to 40% and more across several layers of catalyst. Conversely, other PRB-fired units have experienced extremely clean reactors. To date, no trend can be detected that is responsible for the catalyst plugging – boiler type, inlet NO_x and reactor design, reagent type, etc. have all been evaluated. Figure 8a depicts the plugging on the catalyst surface witnessed below a reactor structural support, and Figure 8b shows deposits on flue gas distribution vanes.

Excessive deposits have been reported have been reported with coals other than PRB, but not to the same extent, unless prompted by LPA. Additional work is necessary to resolve the sources for this blocking, on both PRB and other coals.

Regenerated Catalyst

The use of regenerated catalyst has increased from negligible in the late 1990s, to where regenerated catalyst can for some applications be considered equivalent to new catalyst. The role of regenerated catalyst has been partially responsible for the decrease in catalyst prices witnessed since the mid-1990s.

At present there are at least two major players in catalyst regeneration – SCR Tech and Enerfab. Further, at least one catalyst supplier has teamed with providers of regeneration services to offer this approach.

Figure 8a. Deposits of Ash On Catalyst Surface Below Support Beam

Figure 8b. Deposits of Ash on TurningVanes

Early experience was limited, but additional installations have not identified any fatal flaws or compromises to design. Further, one supplier claims to be able to not restore but actually increase catalyst activity, for a price of approximately 60% of new catalyst costs[19]. As with any evolving technology, additional experience is desired to evaluate how claimed catalyst performance characteristics change with operating time.

Although the fraction of regenerated catalyst as of mid-2006 is small compared to the initial inventory of new catalyst, the technology is a major factor and will provide a cost ceiling to catalyst prices.

Residual NH_3 Monitors

The technology of continuous residual NH_3 monitors has progressed to where equipment is reliable, and can be used if not for process control, then at least as a operating guideline. At present approximately 10 stations employ residual NH_3 monitors on a daily basis, to provide insight as to process operation. The value of the residual NH_3 may not be accurate, but relative trends are. Residual NH_3 data provides operating staff with insight as to both process upsets, the stability of reagent injection during load changes, and the degree of catalyst deactivation or plugging.

CONCLUSION

Since the first SCR applications in the U.S. in the mid-1990s, significant experience has been derived and taught numerous lessons. Accordingly, U.S. SCR applications are unique compared to previous generations. Several problems unique to the U.S., notably plugging by LPA and excess SO_3 production, were not predicted by the suppliers and have been partially but not fully resolved. Although SCR capital costs have been higher than the early estimates, the resultant NO_x control performance as shown by EPA emission rate data has in general supported industry needs. Innovations in achieving uniform NH_3/NO mixing – key to successful performance - have been produced primarily through the use of static mixers, and more detailed and protracted cold flow models or CFD studies of mixing systems. Other innovations such as cleaning catalyst with sonic horns instead of steam-driven sootblowers have become popular, as have urea–derived reagents to satisfy the concerns of local communities. Eventually, the impact of SCR on an Hg control strategy – by oxidizing a fraction of elemental Hg - may supercede all other factors except NO_x control. Future challenges will focus on maintaining catalyst open and catalyst clean, retaining catalyst high activity, and precisely controlling NH_3 injection and mixing.

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