Final Report

ANALYSIS OF MOG AND LADCO'S FGD AND SCR CAPACITY AND COST ASSUMPTIONS IN THE EVALUATION OF PROPOSED EGU 1 AND EGU 2 EMISSION CONTROLS

Prepared for

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Executive Summary

The focus of this analysis is two-fold: (i) to evaluate differences in the levels of FGD and SCR capacity estimated by the Midwest Ozone Group (MOG) and the Lake Michigan Air Directors Consortium (LADCO) in their evaluations of proposed "CAIR-Plus" control measures for electric generation units in the Midwest (EGU1 and EGU2); and, (ii) to assess the difference in control cost assumptions used in both analyses.

LADCO Database Accuracy

The LADCO database does not contain emission controls on several units known to be installed and operating. These include, among others, SCR installations at Merom Units 1 and 2, and Petersburg Units 2 and 3. Omission of these and other control technology installations likely causes LADCO's estimates of SO2 and NOx emissions to exceed expected levels, and thus to impose a higher percent reduction than is actually needed.

Similarity of LADCO and MOG Technology Estimates When SO2 Allowances Are Not Banked

The use of allowance banking in the LADCO study – and how allowances are used – is a primary factor responsible for differences in estimates of technology deployment between LADCO and MOG. LADCO's analyses assume that banked allowances would be used to defer the installation of emission controls, thus deferring the eventual costs of control with EGU1 and EGU2. However, if SO2 and NOx allowance banking is not considered, then estimates of technology deployment between the two studies would be similar.

Significantly Higher Capital Costs

LADCO's capital cost estimates for EGU1 and EGU2 compliance are based on cost assumptions for FGD and SCR that do not reflect actual costs incurred by industry. Specifically, LADCO's FGD capital costs are approximately $200/kW below industry estimates, while SCR equipment costs range from $25 to $45/kW below industry experience. The IPM model's significant understatement of equipment capital costs explains much of the difference between MOG and LADCO's estimates of the costs of implementing EGU1 and EGU2.

Finally, as discussed below, a number of assumptions were made in our assessment of LADCO's control proposals, based on limited information contained in the initial LADCO EGU White Paper. LADCO's subsequent IPM modeling reveals several critical additional dimensions to the EGU proposals, including the use of multiple phases and a "floating" emission rate-based cap. Our estimates of EGU control costs assumed a more traditional tonnage-based cap similar to that used in the acid rain program and the EPA NOx SIP Call.

INTRODUCTION

In January 2005, the Midwest Regional Planning Organization (MRPO) issued a White Paper outlining a possible set of control measures that electric generating units within the states of Illinois, Indiana, Michigan, Ohio and Wisconsin would have to meet beginning in 2008 and with final implementation in 2013. These control measures would establish regional emission caps based upon specified emission rates for both NOx and SO2. Two sets of emission rates are described in the White Paper: referred to as Electric Generating Unit (EGU) 1 and 2. Since the release of this initial White Paper, two economic studies have been conducted to evaluate the compliance implications to electric generators in meeting EGU1 and EGU2. The first study was conducted by the Midwest Ozone Group (MOG) in the spring of 2005.[1] The second study was conducted by the Lake Michigan Air Directors Consortium (LADCO) in the fall of 2006.[2]

This analysis evaluates differences in the levels of FGD and SCR capacity estimated by MOG and LADCO needed to comply with EGU1 and EGU2, and discusses differences in the control cost assumptions used in both analyses. The discussion of cost assumptions is an update of a previous analysis for MOG.[3]

EMISSIONS, CAPS AND CONTROL TECHNOLOGIES – HAS THE IPM ANALYSIS MODELED ENOUGH SO2 AND NOx CONTROL TECHNOLOGY TO ACHIEVE EGU2?

This section evaluates the level of SO2 and NOx control technology that has been modeled by LADCO to achieve the reduction targets outlined by EGU2, and whether the level of capacity approaches the level of capacity modeled by MOG in order to achieve EGU2 emission caps.

It should be noted that LADCO's (IPM) modeled control capacity seems to represent "summer net" capacity, while MOG's estimated control capacity is the "nameplate" capacity of the affected generating units Therefore, to enable a better comparison between MOG and LADCO's modeled control capacities, we converted MOG's "nameplate" to "summer net" capacity.

SO2 and NOx Control Capacity in 2012

Before evaluating the LADCO modeled control capacities for EGU2, we compared the level of existing, planned and modeled FGD and SCR expected to be on-line beginning in 2012 under CAIR. It should be noted that 2012 is also the first year of

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[1] Marchetti, Cichanowicz and Hein, (MCH), *Evaluation of the Midwest RPO Interim Measures and EGU1 and EGU2*, August 1, 2005.
[2] ICF Resources, *Implementation of EGU1 and EGU2 Policies Using the Integrated Planning Model in the Midwest RPO Region*, September, 2006.
[3] Marchetti, Cichanowicz and Hein, *Comparison of FGD and SCR Capital Cost Assumptions Used by MCH and EPA*, September 29, 2005.

implementation of EGU1 and EGU2 in the 5-State MRPO. The MOG capacity levels are drawn from its 2005 study and updated information from the *Emission-Economic Modeling System's* Data Base, while the LADCO capacity levels were obtained from its *VISTASII_PC_1f* run, which includes the 5-State MRPO Region.

Table 1 compares the level of existing and planned capacity in both studies, revealing significant differences between the two sources. Specifically, MOG has identified almost 37.9 GW of FGD capacity that is or will be installed (existing and planned) by electric generators in the 5-State Region by 2012, while IPM only shows 14.7 GW. This same type of differential can also be seen with regard to SCR capacity in the 5-State Region. Specifically, MOG estimates 36.8 GW of SCR capacity (existing and planned) will be in operation by 2012, while IPM only has 26.4 GW operating in 2012.

Table 1: Comparison of 2012 Controlled Capacity in the 5-State MRPO (GW)

FGD Capacity	Existing (2005)	Planned	Modeled	Total
MOG	12.0	25.9	2.2	40.1
LADCO	11.9	2.8	18.4	33.1
SCR Capacity				
MOG	27.5	9.3	9.1	45.9
LADCO	23.0	3.4	10.3	36.7

Note: 1. Existing is installed capacity for year end 2005.
2. Planned capacity is based upon announced FGD and SCR systems by electric generators in the 5-State MRPO.

Even taking into account the modeled capacity (additional technology required beyond already known deployments) to meet CAIR for both SO2 and NOx, the IPM results fall significantly below the MOG results. Consequently, there is a concern that base data used in the IPM analysis is not reflective of industry experience/compliance, specifically with regard to what is installed and planned to be installed. For example, MOG indicates there are 27.5 GW of existing SCR capacity, while LADCO (IPM) shows only 23.0 GW, a 4.5 GW difference. In reviewing the IPM file (*VISTASII_PC_1f*), we noticed several operating SCRs missing, including E.W. Stout 7 (422 MW), Merom 1 & 2 (1,020 MW), Warrrick 4 (270 MW) and Petersburg 2 & 3 (917 MW). Therefore, if the base data is not correct, the question then arises whether the modeled data is a realistic representation of industry compliance and thereby may have *over-estimated* pre-EGU 1 and 2 SO2 and NOx emission levels.

SO2 and NOx Control Capacity to Meet EGU2

The LADCO report contains several new elements related to EGU compliance with EGU1 and EGU2, which were not made known to us when our original work was undertaken in the spring of 2005. These new elements are as follows:

- EGU1 and EGU2 compliance date is 2012, whereas, the MOG analysis assumed 2013;
- The EGU SO_2 and NO_x emission caps are moving or floating caps, which change from year-to-year based upon changes in annual heat input, unlike the MOG caps which are fixed and based upon a historical baseline;
- Compliance with EGU1 and EGU2 utilizes two phases: (i) Phase I is from 2009 to 2011, which has caps based upon the Interim Measures in the White Paper; and, (ii) Phase II is 2012 and beyond and has caps based upon EGU emission rates from the White Paper;
- MRPO electric generators that over-control in Phase I are able to carry-forward their excess/banked allowances for compliance in Phase II. This feature was not included in the MOG analysis because phases were not assumed or modeled and the White Paper *did not* mention that generators would be allowed to carry-forward allowances from a earlier phase; and,
- MRPO electric generators are allowed to sell excess/banked allowances from EGU1 and EGU2 compliance to electric generators outside the 5-State MRPO Region.

Our review compares incremental control capacity, as modeled by MOG and LADCO, which generators in the 5-State MRPO Region would install under EGU2. The LADCO EGU2 policy run is identified as *LADCO_PC_1d*. However, both analyses were modeled under different regulatory regimes; therefore, our approach compares outcomes under a similar regulatory regimes and data. As mentioned above, the MOG analysis assumed a 2013 compliance date, with no carry over of allowances from any earlier phases. Under this type of regulatory regime, electric generators within the 5-State MRPO Region would be required to meet EGU2 SO_2 and NO_x emission caps by that date. The LADCO analysis indicates EGU2 would be implemented in 2012; however, between 2012 and 2020, generators are allowed to carry-forward both SO_2 and NO_x allowances for compliance, as illustrated in Table 6 of the LADCO report.

There is a particular concern with regard to modeling in 2012. The LADCO report illustrates in 2012 affected units within the 5-State MRPO Region would have SO_2 emissions of 432,000 tons under EGU2. Also shown in Table 6, the 2012 EGU2 SO_2 emission budget computed by IPM is 473,000 tons, which seems to allow the banking of excess allowances. However, there may be an issue concerning the precision of the IPM model related to emissions and banking, which ultimately would affect the deployment of technology. Since the model *does not* evaluate compliance on an annual basis, the LADCO report indicates the 2012 cap is an average of 2010 – 2013 year caps, which encompasses the two phases of EGU2. Also, the related LADCO Stratus report seems to imply on pages ES-2 and ES- 4 that the SO_2 emissions may be an average of the same years.[4] As mentioned earlier, Phase II of EGU2 compliance begins in 2012, when affected EGUs would have to meet SO_2 emission caps based upon an SO_2 emission rate

[4] Stratus Consulting Inc., *Benefit Study of MRPO Candidate Control Options for Electricity Generation*, August 25, 2006.

of 0.10 lbs/mmbtu, and not an average or hybrid cap. Consequently, the lack of precision in the LADCO IPM report could erroneously project a 2012 EGU2 SO2 cap and emissions that are too high. *This error creates unrealistic SO2 reduction targets and allowance banks from 2010 to 2013, which results in the deferral of technology deployment beyond 2012.*

Differences in Heat Input Assumptions

Regardless of these concerns about banked allowances, our review of the LADCO report suggests that by 2020 electric generators would achieve the 2020 SO2 EGU2 cap *without* the use of banked allowances. Further, their NOx emissions would be slightly above the EGU2 cap, requiring the withdrawal of a small amount of banked NOx allowances. In addition, as best as we can determine, LADCO's 2020 regional heat input of 6,011 TBtu is comparable to MOG's 2013 regional heat input of 6,088 TBtu.[5] A discrepancy does arise when performing the same calculation using the 2020 NOx EGU2 cap (from Table 6) and the EGU2 NOx emission rate. This method provides an estimate of 2020 regional heat input of 6,482 TBtu, representing a significant difference. Therefore, two questions arise: (i) is there a computational error in computing the regional heat input; or, (ii) has the LADCO report included more capacity in computing the EGU2 NOx budget than they used in computing the EGU2 SO2 budget. Since this question cannot be answered based upon the available information in the LADCO report, we used the regional heat input derived from the SO2 budget of 6,011 TBtu. This value is very close to MOG's 2013 regional heat input (for units >25 MW) of 6,088 TBtu, and allows a better comparison of technology deployment.

Therefore, comparing MOG's 2013 technology deployment with LADCO's 2020 technology deployment is appropriate, because LADCO's compliance requires either very little or no use of allowances, and the regional heat input is comparable to both studies. However, we were unable to obtain and review the IPM parsed files for 2018 and 2020 for the EGU2 policy run (*LADCO_PC_1d*); consequently, we had to make some inferences on the level of FGD and SCR capacity that would have to be installed within the LADCO region to meet EGU2 in 2020. To do this, we evaluated two distinct data sets, based upon available data.

Because only aggregated information is available from the LADCO report, we can make only initial comparisons between MOG's 2013 compliance and LADCO's 2018 compliance estimates. As shown in Table 2, MOG's FGD capacity in 2013 is about 9.3 GW greater than LADCO, while MOG's SCR capacity is 13.1 GW greater than LADCO.

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[5] The 2020 LADCO regional heat input is determined by dividing the 2020 SO2 EGU cap of 301,000 tons (from Table 6) by the EGU SO2 emission rate (0.10 lbs/mmbtu) yields a regional heat input of 6,011 TBtu.

Table 2: Estimated Incremental FGD & SCR Capacity under EGU2 (GW)

Study	FGD	SCR
MOG (2013)	60.7	41.0
LADCO (2018)	51.4	27.9

As mentioned earlier, the LADCO analysis allows for the banking and carrying forward of allowances, which allows for the *deferral* of both FGD and SCR deployment, while the MOG analysis did not allow for this type of banking. Even with the use of banked SO2 allowances for compliance and a less stringent emission cap in the LADCO analysis, the levels of FGD capacity in the two studies are very close. So the question arises, when the banks are drawn down to zero, would the LADCO FGD and SCR capacity mirror the MOG capacity?

Comparison of Emissions and Caps

Evaluating regional heat input and emissions in 2020 may provide additional insight. Using the regional heat inputs described earlier and computed emission rates from Table 6 of the LADCO report yields the following emission/cap comparisons for both studies:

Table 3: 5-State SO2 & NOx Emissions and Caps under EGU2 (tons)

	MOG (2013)			**LADCO (2020)**		
	Emissions	**Cap**	**Over/Under**	**Emissions**	**Cap**	**Over/Under**
SO2	**371,536**	**304,403**	**67,133**	**300,530**	**300,530**	**0**
NOx	**249,203**	**213,082**	**36,121**	**213,391**	**210,385**	**3,006**
Regional Heat Input	**6,088 TBtu**			**6,011 Tbtu**		

Note: 1. The 2020 LADCO NOx emissions are based upon multiplying a computed NOx emission rate (from Table 6) of 0.071 and multiplying it by the LADCO regional heat input.
2. The SO2 and NOx caps for both MOG and LADCO were computed by multiplying the EGU2 SO2 and NOx emission rate by the regional heat input.

As shown in the above table, both the SO2 and NOx emission caps for both MOG and LADCO are very close; however MOG's emissions are higher. The primary factor affecting the emissions disparity between MOG and LADCO are assumptions defining the capabilities of control technologies. LADCO assumes more aggressive control levels can be achieved by FGD and SCR technology. Specifically, LADCO estimates that electric generators would achieve a NOx emission rate of 0.071 lbs/mmbtu and a SO2 emission rate of 0.10 lbs/mmbtu by 2020. In comparison, MOG estimated control levels of 0.082 lbs/mmbtu for NOx and 0.122 lbs/mmbtu for SO2.

It should be noted that MOG modeling to achieve these NOx and SO2 emission rates showed 18.6 GW of existing coal-fired capacity would switch to PRB coal with FGD systems. The LADCO study still models a NOx bank; however to achieve a region-wide SO_2 emission rate of 0.10 lbs/mmbtu it would seem the LADCO modeling would require either: (i) a larger shift to PRB coal with scrubbing within the 5-State Region than projected by MOG; or, (ii) the retirement of a significant amount of existing coal capacity. *Therefore, it seems the use of banked allowances has allowed LADCO to defer the level FGD and SCR capacity to 2020 or beyond what MOG projected in 2013 under a no allowance carry-over regime. This suggests that the compliance implications discussed by MOG eventually would occur in the LADCO modeling if it were extended further in time.*

IPM COSTS AND INDUSTRY EXPERIENCE

This second section of the analysis provides an update of control technology capital costs for flue gas desulfurization (FGD) and NOx control, focusing on wet FGD for the former and selective catalytic reduction (SCR) NOx control for the latter. The wet FGD process cited in this documents refers to a wet limestone-based process, producing gypsum as a byproduct, and capable of 95-97% SO_2 removal, depending on coal composition and averaging time.

Background

There is considerable information both in the public domain and reported anonymously describing the capital and operating cost of process equipment to control SO_2 and NOx. Significant discrepancies exist among these various data sources provided by equipment suppliers, EPA, and industry.

Recent capital cost estimates for conventional wet FGD and SCR reported by owners significantly exceed those estimated using information published by the supplier community or the EPA. Several factors are likely responsible for this discrepancy; one significant factor is the strong demand for environmental control equipment, coinciding with strong demand for general chemical process facilities. The confluence of these demands escalates the cost of labor and materials essential for this category of equipment. Compounding these differences in capital cost estimates is that some source data from EPA may not represent current market conditions, due to both the methodology and timing of the estimate.

It is instructive to consider the escalation in the cost for chemical process equipment. One popular indicator of such costs is the Chemical Engineering Plant Index, which reflects the escalation in cost for a wide variety of process equipment. Figure 1 depicts the change in the Chemical Engineering Plant Index (Chemical Engineering, 2006) reflecting the construction cost of general plant process equipment, specifically from 1995 through mid-2006.

Figure 1: Chemical Engineering Plant Index (CEPI): 1995 – July 2006)
(Note: 1957-1959 = 100)

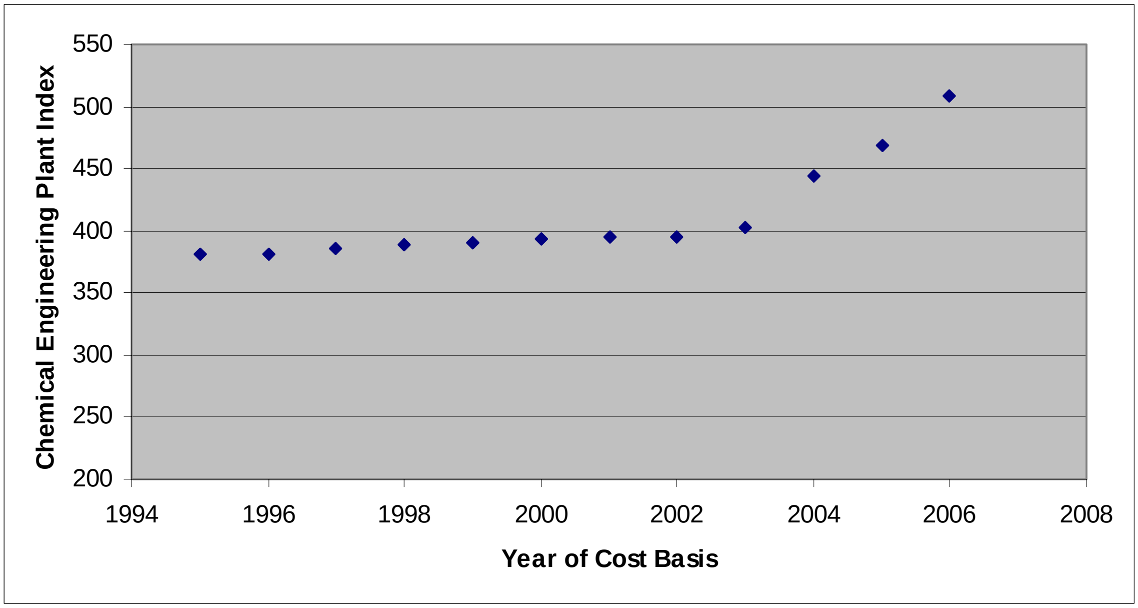


Figure 1 shows little change in the Chemical Engineering Plant Index from 1995 through the end of 2003, but 2004 marked the beginning of significant escalation that continues unabated. This trend reflects several factors important to environmental controls, such as escalation in material cost for upgrading electrical equipment. Due to intensive use of copper and a four-fold increase in copper prices, this index has risen rapidly since 2003. Competition for materials from China, driven by their rapid electrification program, is adding demand-push pressures to U.S. pollution control construction costs. Figure 1 shows that even with all other factors equal, cost escalation due to a robust demand will increase installed cost of process equipment.

Comparison of FGD Estimates: 2000-2006

Estimates of capital and operating cost for both wet and dry FGD equipment have been derived in the last five to seven years from a variety of sources. These include estimates for CAIR compliance, specific costs announced for CAIR retrofits, and projections by EPA and regulatory agencies based upon knowledge of equipment cost and availability. Compounding the complexity of preparing realistic cost estimates is the uncertainty in labor pool availability and cost, and the project scope – what equipment changes are included or excluded in the budget. This section summarizes the cost trends noted prior to the year 2006.

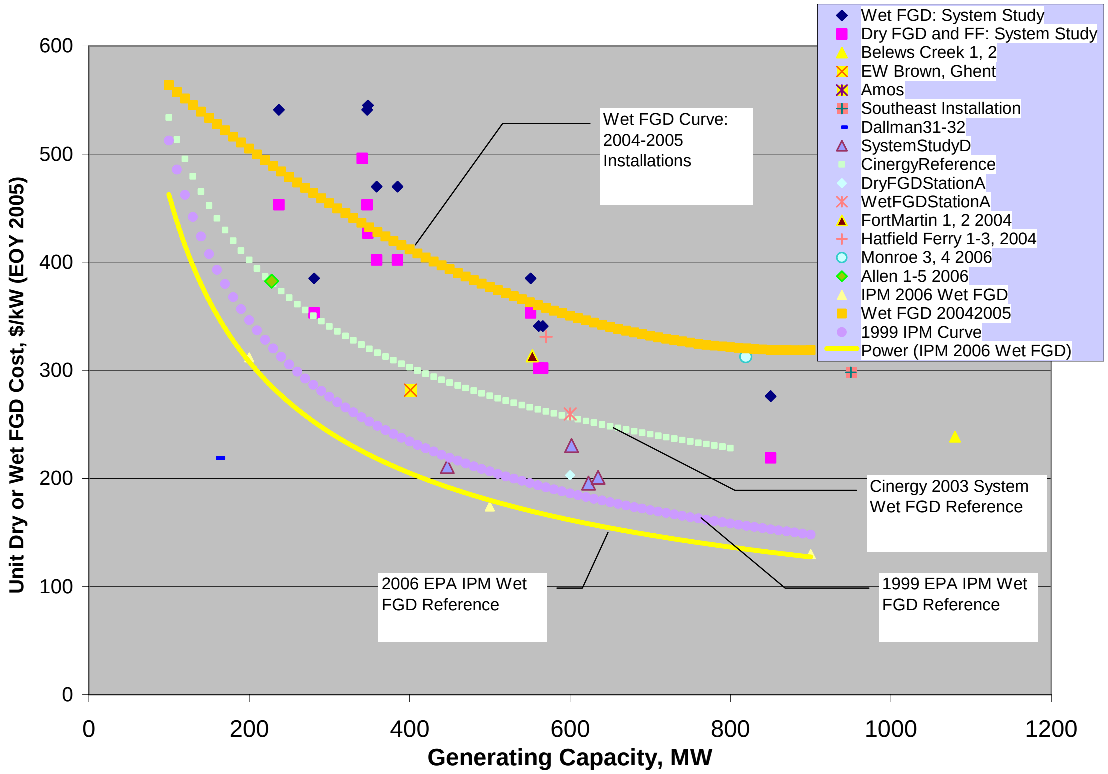
Figure 2 presents a summary of FGD capital cost, shown as a function of unit generating capacity, for both dry and wet FGD, derived from a number of sources. All reported equipment costs have been adjusted to the end-of-year 2005, using the GDP escalating factor. It should be noted that FGD costs for all generating stations are reported per unit of generating capacity, even for system-wide designs for large generating systems. For example, FGD capital for Duke Energy's Allen Units 1-4 is reported for a single Allen unit capacity of 270 MW; however the design is predicated on the generating capacity of the entire station of 1200 MW. Consequently, the available economies of scale – particularly important in reagent receiving and solid byproduct management - serve to reduce the unit cost.

Figure 2 shows a wide disparity in projected costs between several sources and periods of time. These are discussed in the following sections.

2006 EPA IPM Data

The lowest capital cost projections for wet FGD are derived by EPA using their IPM cost correlations, which are applied for EPA modeling of system compliance costs. The IPM supporting documentation (EPA, 2006) and the key source papers (Staudt, 2006, and Khan, 2004) describe the basis of the estimates. The estimating methodology appears to reflect authentic utility cost accounting, and considers both direct and indirect costs. However, it is not clear if these estimates reflect a complete suite of balance-of-plant items, such as upgrade of flue gas fans and electrical distribution components, or reflect the most recent market conditions.

Figure 2: Wet and Dry FGD Capital Cost: Estimates Prior to 2006 (End-of-Year 2005 Dollar Basis)



The EPA IPM capital costs were based on soliciting budget estimates of uninstalled capital equipment costs – and as stated in the reference paper (Staudt, 2006) only one response was received. It is possible that the exploratory and budgetary nature of the estimate as developed by the supplier resulted in an atypically low estimate, which could not be detected by comparison to other sources. In addition, the supplier developed equipment costs for a new "greenfield" application, with the installed retrofit cost provided by a semi-quantitative "retrofit" factor. The retrofit factor selected for this analysis of 1.3 – an appropriate selection by historical standards – may be too small to reflect the complexity of the most recent sites for which FGD is considered. It is widely believed that the first 100,000 MW of FGD capacity retrofit were installed first on those units that provided the lowest removal cost ($ per ton basis), which implies the least capital cost. The units remaining may present more challenging site conditions for retrofits.

Also shown in Figure 2 for comparison is the wet FGD capital cost curve used by EPA in IPM modeling in 1999, which has served as the basis for all but the most recent IPM modeling runs. The projected capital costs (also in end-of-year 2005 dollars) are slightly higher than the updated 2006 cost curve. It is not clear why the 2006-derived costs are lower, given significant increases in demand and material cost as shown by Figure 1.

Cinergy 2003 System Wet FGD Study

A comprehensive evaluation of wet FGD cost for the Cinergy system was conducted in 2003 by Sargent & Lundy Engineers. Individual data points derived in this analysis are not shown but the curve fit for the seven units in the study is reported and corrected to an end-of-year 2005 dollar basis. The shape of the curve is similar to that projected by EPA, but for the same generating capacity, Cinergy projects approximately $75 to $100/kW higher capital cost.

2004-2006 Industry Estimates

Figure 2 reports a locus of points for both wet and dry FGD, derived from numerous cost references in 2004 and 2006, some of which are public. For example, AEP published wet FGD capital cost for Amos, and Allegheny Energy for both Hatfield Ferry Units 1-3 and Fort Martin Units 1 and 2. Detroit Edison released capital cost for Monroe Units 3 and 4. Duke Power released costs for Belews Creek and five units at Allen, the latter each 270 MW but totaling 1200 MW of generating capacity. LG&E energy similarly published results for E.W. Brown and Ghent.

Several anonymous sources contributed cost estimates based on thorough engineering procurement studies: a southeast utility and two system studies for operators in the Midwest.

The locus of data points from these estimates –all derived during the 2004-2006 timeframe – is shown. Also shown is a curve reflecting the general relationship between these data points. Significantly*, these costs exceed those projected by EPA for IPM by over $200/kW – more than double the projected level*.

Sources for Cost FGD Differences

There are several reasons why EPA and industry-generated wet FGD capital costs differ to the extent reported in Figure 2. Each of these is addressed in the following sections. The individual data points on Figure 2 may not all be directly comparable. Except for adjusting all cost estimates to an end-of-year 2005 dollar basis, no effort has been made to assure a uniform basis. The following factors, also included in the EPA methodology (Staudt, 2006), are all usually derived as a fraction of the total process capital, which describes the total cost for process equipment prior to installation. The cost factors are described as follows:

<u>Engineering and Construction Management Charges</u>. The cost for engineering services to define the design of process equipment, and management of these services, is generally 10%, similar to that assumed by Staudt (2006). It is possible that challenging retrofit requires greater engineering expenditure.

<u>Process & Project Contingency</u>. The usual assumptions for these standard contingency values for the relatively mature wet and/or dry FGD is 10% and 5%, respectively. For

reported costs that reflect firm prices from suppliers, it is unlikely any such charges are included as line-item cost elements. For these fixed price bids, each equipment and process supplier will utilize an internal proprietary margin to account for uncertainties. Projects that are conducted on an "open book" basis with a strategic partner will not include such cost elements, but allow cost recovery if actual incurred costs exceed those predicted.

General Facilities. This cost element covers roads, providing for special access, and buildings; any differences are expected to be small.

Contractor Profit/Fees. These charges can be 5-10% of the total

Project Scope. The specific equipment included in the FGD budget can vary. For example, Staudt (2006) discusses the possibility of fan modifications and ductwork changes in an FGD retrofit, but these items are not addressed in the cost estimate. The additional resistance to flue gas flow for a conventional wet and dry FGD system – from 4 to 8 in w.g. – will in most cases require some type of fan upgrade. Further, depending on how the flue gas handling system was originally designed, a significant run of ductwork may have to be strengthened, to avoid damage from significant negative pressure. Again, there is no indication these or the costs – albeit very site specific – are included in the EPA-derived estimates.

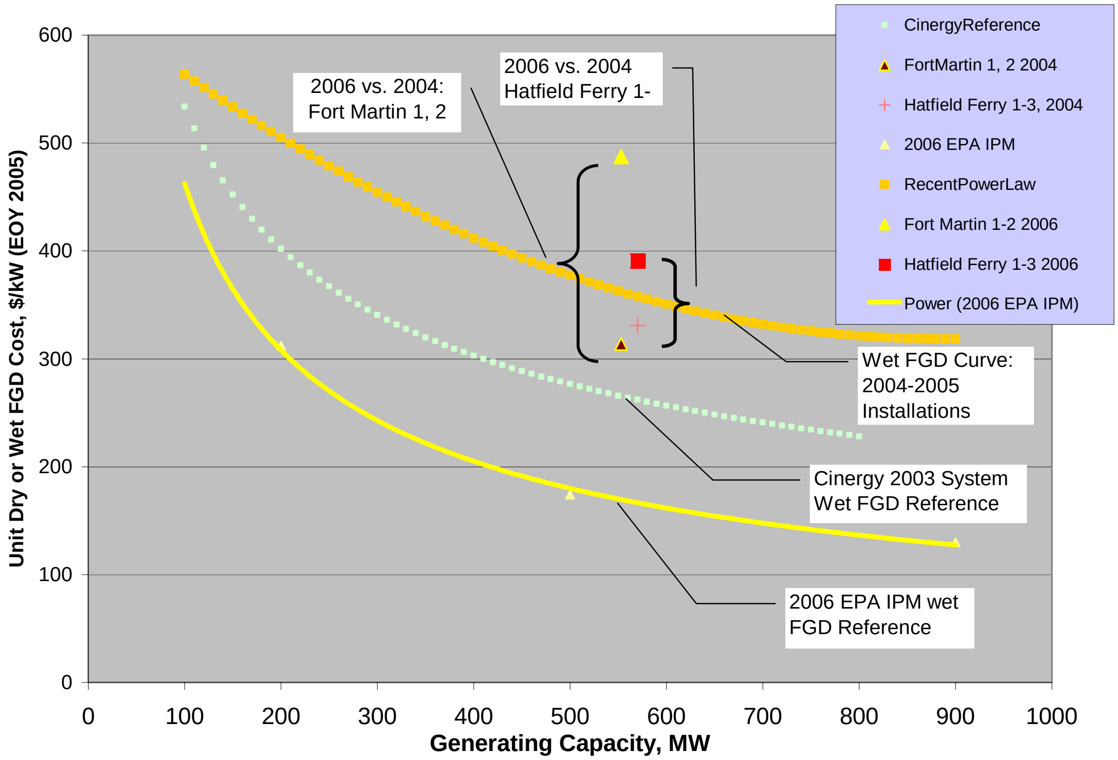
Timing of Costs. The significant demand in flue gas processing equipment – for both FGD and SCR – has evolved into a premium for equipment and services since 2000, and especially so in the last year.

The role of the project schedule and the subsequent timing of the cost estimate are shown by Figure 3. This figure repeats the curve-fit description of capital cost presented in Figure 2, along with 2006 revised costs as reported for two Allegheny Power stations – Fort Martin and Hatfield Ferry. Fort Martin's capital costs escalated significantly from estimates prepared in 2004.

Discussions with representatives of architectural engineering companies involved in wet FGD procurement indicate that a strong demand for essential equipment and services is responsible for the cost escalation. Specific examples are:

Limited access to flue gas fans and slurry pumps. A limited number of equipment suppliers are qualified to provide the large, high reliability fans for flue gas and pumps for process slurry that are critical to reliable performance. At present, the manufacturing capabilities of key suppliers are booked – and establish the limiting step in FGD installation of 30-36 months. Both the shortage of equipment and willingness of purchasers to pay to expedite procurement contribute to these higher costs.

Figure 3: FGD Capital Cost: 2004 vs. 2006 Estimates (End-of-Year 2005 Dollar Basis)



Some observers have noted that the U.S. utility industry qualifies a limited number of suppliers of this equipment, and that relaxing qualification requirements is one way to increase the number of suppliers (Hartenstein, 2006). Given the large and complex nature of recent system FGD installations, it is not known if this action would introduce the use of equipment with less proven reliability.

Limited Stack Erectors. Similarly, there are reportedly a limited number of suppliers world-wide that can fabricate the wet stack designs required to withstand the wet flue gas from FGD. Similar to the case for flue gas and slurry equipment, this can be a limiting step in FGD process installation. At present, it is reported that the four major stack erectors are booked through 2010; any new installation reportedly will not be able to install new wet stacks before the beginning of 2011.

Electrical Equipment. The requirement for additional power for pumps, fans, and associated equipment can significantly increase the on-site demand for power, and distribution such as motor control centers for power management and distribution. The cost of these upgrades – dependent on copper-containing products – has increased reflecting the four-fold increase in copper prices in recent years. Upgrade of electrical subsystems – historically 6-8% of an FGD project - can now exceed 15%.

Installation Difficulty. The units reflected in Figure 2 and 3 represent approximately the second 100 GW of wet FGD installed. As discussed previously, the first 100 GW were initially selected for a large number of reasons – of which ease of retrofit and low capital cost was likely the most significant factor. It is these early applications that provided the bases for the historical retrofit factor of 1.3. It is likely that units within the second 100 GW of retrofit candidates represent more difficult retrofit applications, which the historical 1.3 retrofit factor does not capture. Compounding the retrofit difficulty is the higher cost of labor, due to shortages reported by many operators of FGD process equipment.

In summary, the capital cost for wet FGD process equipment between estimates derived for use in IPM modeling and industry-reported costs differ significantly, by approximately a factor of two. The key reasons for this difference are likely the timing of the estimates (e.g. reflecting 2005 and 2006 market conditions), the complexity of the retrofit sites, and the scope of equipment included.

The consequence of the difference in capital cost, combined with differences in operating cost assumptions (the latter not addressed in this document) is a similarly wide difference in calculated cost per ton ($/ton) of SO2 removal. Specifically, the reported marginal cost values in Table 3 of the ICF report for the EGU2 category notes a range from $1,847 to $2,951/ton for SO2. In contrast, the recent analysis of the authors evaluating the IL Mercury Rule reports dry FGD removal costs between $2,600 and $4,200/ton.[6] These costs are based upon inputs from system generators in Illinois and reflect industry FGD capital costs discussed in this section.

SCR NOx Control

Similar to the case of wet FGD, capital cost estimates derived for SCR NOx control from industry-reported sources and EPA differ significantly. Several reports of SCR capital cost have been published in recent years (Hoskins, 2003; Cichanowicz, 2004; Marano, 2006). The most detailed and comprehensive analysis is provided by Marano, reporting global trends based on approximately 70 SCR installations erected between 1999 through 2005. As shown in Table 4, Marano reports most SCR costs range from $100 to $200/kW. There is a noted increase in capital cost for units installed after 2003.

It is instructive to compare the trend in reported and estimated SCR capital between industry sources and projections by EPA. Figure 4 depicts this trend, utilizing the individual data points reported by Cichanowicz. (Marano did not report individual data so developing such a trend is not possible). Figure 4 shows the wide disparity in capital cost for industry-reported units, which vary by a factor of two or more. The industry-reported data show that increasing generating capacity does not always lower unit (e.g. per $/kW) process cost, as the complexities imposed by the larger generating sites can complicate installation and elevate cost. Also shown on Figure 4 is the trend in projected SCR capital using the relationship employed in EPA IPM modeling (Khan, 2004). This trend is well below that reported by industry.

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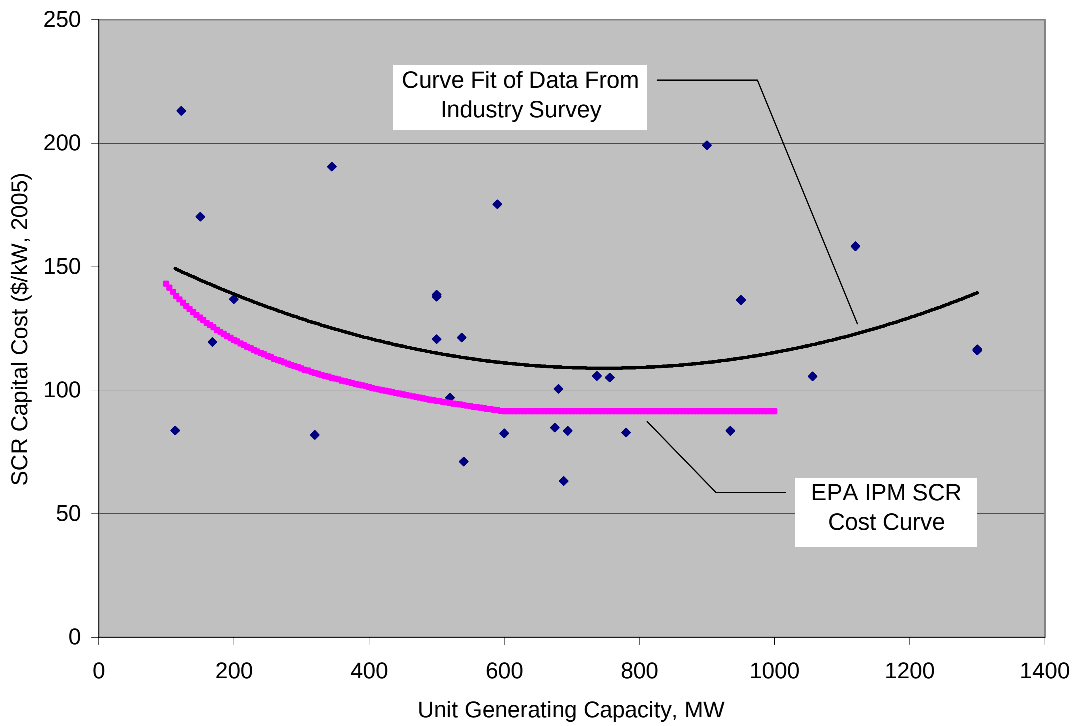
[6] Testimony of James Marchetti before the Illinois Pollution Control Board in rulemaking R06-25 dated July 28, 2006.

Table 4: 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."

As explained by Khan (2004), the EPA IPM methodology uses reports of industry SCR costs but adopts these into a fixed scaling relationship. In contrast, we relied on the trend curve depicted in Figure 4 to estimate SCR capital costs.

Figure 4. SCR Capital Cost: Industry Reports versus EPA IPM Modeling (2005 End-of-Year Dollar Basis)



The reason for the disparity in SCR capital costs is likely the same as cited for wet FGD: the recent escalation in material prices has elevated the cost of materials and labor, and the plant sites for industry-reported costs may be more complex than earlier estimates. Consequently, *the difference between EPA and estimates derived from industry experience for SCR equipment can range from $25 to $45/kW.*

Similar to the case for wet FGD, the EPA IPM cost assumptions for SCR are significantly below those reported by industry. The consequence of the difference in capital cost, combined with differences in operating cost assumptions (the latter not addressed in this document) is a similarly wide variance in calculated cost per ton ($/ton) for SCR NOx removal. Specifically, the reported marginal cost values in Table 3 of the ICF report cites for the EGU2 category a range from $$639 to $1,020/ton for NOx. In contrast, the MCH recent analysis evaluating the IL Mercury Rule reports SCR NOx removal costs between $1,500 to $9,800/ton.[7] These costs are based upon inputs from system generators in Illinois and reflect industry SCR capital costs discussed in this section.

[7] Ibid.

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