A GENERAL DISCUSSION OF

INDUSTRIAL AIR POLLUTION CONTROL PROJECT COSTS WITH CONTROL EQUIPMENT COST REPRESENTATIONS

Each time EPA or States decide to tighten environmental standards, there is disagreement over the true cost of the control equipment and how these costs measure up against the benefit to society of regulations. It is important to accurately estimate costs, because they are an important component of the government's analysis of whether the additional environmental improvement and benefit to society justifies the cost of the new regulation. When government increases the cost of doing business for US companies, that also affects society in the form of productivity, labor force and even the continuing presence of the manufacturing sector in the US. The industrial manufacturing and institutional boiler community consistently take the position that state and federal emission control project cost estimates are too low and the impacts on the community of the cost increases are not thoroughly considered.

CIBO believes that low cost projections are mostly due to a lack of understanding of the cost and complexity of an equipment upgrade at an existing manufacturing facility to meet new environmental standards. In an attempt to fill the information gap, CIBO provides this discussion of the cost of retrofit emissions control technology to the industrial sector. This document will 1) describe how a facility achieves a retrofit installation of emissions control technology and identify cost factors, and 2) provide data demonstrating where EPA cost estimates tend to be inaccurate (Attachment A). The narrative portion of this discussion focuses on the complex process a company goes through to plan and execute an equipment retrofit at an existing facility. The data portion (Attachment A) of this discussion analyzes EPA cost estimates for retrofit NOx and SO2 control technology and shows how cost estimates have been underestimated.

BACKGROUND

Before we begin, it is important to know who we are and to provide some context relative to other regulated sources for our discussion. The Council of Industrial Boiler Owners (“CIBO”) is a national trade association of industrial boiler owners, architect-engineers, related equipment manufacturers, and universities representing 20 major industrial and institutional sectors. CIBO was formed in 1978 to (1) promote the maximum exchange of information between industry and government relating to energy and environmental policies, laws, and regulations affecting industrial boilers and the manufacturing and institutional energy base of our country; (2) promote technically sound, equitable and cost-effective laws and regulations; and (3) improve energy and environmental performance, reliability and cost-effectiveness of members’ operations through technical interchange and advocacy.

CIBO membership represents industries as diverse as chemical, paper, cogeneration, steel, automotive, refining, brewing, combustion engineering, and food products. CIBO members also include operators of boiler facilities at over a dozen major universities. CIBO speaks for the industrial energy base of the nation. Without the industrial energy facility, there would be no products and there would be no jobs. For 27 years, CIBO has been promoting the better integration of our nation's energy and environmental policies and regulations. As CIBO members well know, energy and environment matters are inextricably linked.

It is helpful to provide context for understanding the economic impact of equipment improvements at the industrial facility or university powerhouse. In our experience, regulators often use as a benchmark for estimating industrial facility costs, the cost of installing similar equipment at a utility facility. This apples-to-oranges comparison yields widely inaccurate estimates. The relative cost of an industrial project can be deceiving for a number of reasons.

A typical industrial facility lacks space for siting new control equipment. Unlike large utilities, which usually have available space, industrials must spend more in planning, engineering design and sometimes land acquisition to site the control equipment.[1] At a typical industrial facility or university powerhouse, integration within the existing facility, with its structural and capacity limitations, can be extremely complex and costly. Another difference is size. Unlike large utility systems, industrials cannot count on economies of scale, so even incremental costs make a difference. For example, an added project cost of $100,000 is 10% of a $1,000,000 industrial project, whereas the same $100,000 is only 0.1% of a $100,000,000 utility project. This becomes an extremely important factor for the industrial facility, especially when particular equipment such as a Continuous Emission Monitor (CEM), is required. The cost of the CEM is the same regardless of the size of the facility.[2]

Emission control equipment is a tool for the greater purpose of improving public health and the environment. The *overall cost* of obtaining the objective is much more than the cost of the tool. And for every entity involved in equipment control issues, the costs associated with acquiring and using the tool vary. "Control costs" means different things to the equipment supplier, general contractor and industrial facility or university with an emission control requirement. Because every environmental project is different and different costs are associated with the different perspectives, disagreements arise about what represents real costs. So, what is the *true total cost* to a facility to upgrade its emission control equipment to meet new environment requirements? The answer is found by understanding what makes up the cost of an industrial pollution control project.

THE ANATOMY OF AN INDUSTRIAL POLLUTION CONTROL PROJECT

Two primary cost categories are associated with pollution control projects: the one-time Capital Cost and the on-going Operation and Maintenance Cost (O&M). Here we will discuss the total capital cost to an owner of an emission control technology, although

[1] The differences between industrial and utility facilities -- and the added challenges for industrials -- are discussed in more detail in Attachment B.

[2] The cost of a CEM does not change whether it is applied to small industrial boiler or large electric utility boiler that dwarfs the industrial units. In any case, the smaller the project, the lower the administrative cost burden that can be tolerated.

ongoing operation and maintenance costs can have just as serious an impact on the viability and cost effectiveness of a control technology. O&M costs vary by type of manufacturing process, equipment installed, current configuration, company-specific financial conventions, staffing of the industrial energy facility, along with multiple other factors. We reserve those issues for another discussion paper.

The initial capital cost associated with an industrial pollution control can be broken into five (5) distinct function and cost areas:

A. Total Capital Cost
   1. Planning and Permitting
   2. Equipment Design, Selection and Engineering
   3. Equipment Fabrication, Construction and Installation
   4. Equipment and Process Facility Integration
   5. Training, Start-up, Testing, Monitoring and Reporting
B. Operation and Maintenance Cost

The installation costs associated with a pollution control technology or project must take into account all costs associated with the first five functions above (recognizing the critical importance of O&M costs, which are a separate discussion). As mentioned, the total project cost is more than pollution control equipment cost. In the following, we will look at the individual stages of the project and assess how they impact the total cost.

Planning and Permitting

In today's world, every company strives to be a good steward of the environment, and views environmental regulations as integral to future project planning and development. Planning for future environmental regulations is like driving with the seat belt fastened - it has become second nature. This thinking partially drives the initial scrutiny of any project, which includes a review of facility needs, environmental implications and cost effectiveness. Various equipment alternatives are considered including new unproven innovative technologies and the possibility for fuel switching. Capital projects must be considered against capital funds availability, risk of failure and the global benefit to the corporation via an initial budget price evaluation (+/- 30%) and other corporate financial tools.

Switching from one fuel (typically coal) to a cleaner-burning fuel (typically natural gas) may be considered by some facilities as a means to reduce emissions. While switching to natural gas may appear to be simple, any change in fuel from the original design fuel for the boiler could require significant capital investment and evaluation as would any pollution control technology alternative. This is where a company must consider the operating costs in its decision of the best control alternatives. While the switch to natural gas may have the lowest capital costs, it may have the highest ongoing operating costs and many not be an economically viable solution for the facility. In addition, natural gas, the most common choice for fuel switching, is not available to all facilities due to transportation and distribution system limitations. The current natural gas supply/demand imbalance and resulting inflated prices create a significant fuel price differential penalty for use of natural gas. This already is forcing companies that lack diversity in their fuel supplies to shut down or move production to other countries. With no real solutions in sight for this situation in the short-term, the use of natural gas as fuel must be evaluated carefully against the overall corporate plans for an emissions control project, long-term energy requirements, and needs for that facility and the production affected.

When corporate engineering and planning staff do the planning and permitting work for the pollution control project, their time may not be capitalized with the final project cost. However, if the complexity of the project is significant enough to warrant an outside consultant to perform studies and make recommendations, these outside costs are typically capitalized with a final project. Because most industrial companies have limited their in-house energy and engineering staffs to keep overhead costs low, they usually need outside assistance for projects beyond normal operation and maintenance of the facility.

Once a project passes initial scrutiny for facility needs, environmental soundness and cost effectiveness, the initial engineering and permitting process begins and does not end until the operating permits are issued. In this initial engineering phase, project and equipment specifications are developed based on permitting requirements. Specifications are used to define equipment performance requirements that will be the basis for later equipment design and cost proposals. Separate permit applications if needed for construction and for operating the equipment are initiated, in coordination with the regulatory officers from local, state and federal governments. Depending on its complexity, a pollution control project could take from six months to two years to obtain final construction and operating permits from regulatory agencies. This will require countless hours of legal and technical support, hours that are not available within the company staff, to address regulatory and technical questions posed by permitting authority.

The time and cost of the permitting process is relatively independent of the size and capital cost of the pollution control project. The permitting authority and stakeholders need to ask the same questions for any project, regardless of its size, benefit or impact. In many cases the process is iterative, taking one of two approaches: a top-down approach, based on the best control that any facility has installed without regard to cost or applicability to another facility; or a bottom-up approach, based on the best emission reductions possible at reasonable costs to decrease emissions and meet all applicable regulations at that facility. Equipment supplier guarantees are critical to the permitting process. Because no two facilities are alike, a proven control device for one facility may not achieve the same emission reduction rates at any other facility.

Through the iterative process the project engineering and design may change significantly before the final construction permit is issued. At that point, detailed equipment design and project engineering can proceed in earnest. This is also the time when detailed pollution control project parameters are defined, project costs are refined, and the decision to proceed is finalized. For the industrial facility, the available project alternatives must be considered at the corporate level, and will likely include these options: proceed with the project, stop the project and do nothing (assuming that is possible), and consider the impact on global production capability and whether to shift production requirements to avoid the capital cost at that facility. If the project moves forward, the process for obtaining the final operating permit continues through the start-up and testing.[3]

Equipment Design, Selection and Engineering

Based on equipment specifications and performance requirements identified for the pollution control project a company must seek proposals for the equipment and services, evaluate the proposals and contract with suppliers. A company prepares and puts out for bid a Request for Proposals (RFP), which becomes the blueprint for the entire project, and the primary reference for major capital expenses. The scope of the overall proposal will outline the specific performance requirements and any details that will help the equipment supplier provide a realistic proposal with supportable guarantees for meeting the environmental requirements and the overall needs of the company.

A clearly defined project scope is critical to obtaining price estimates that can be compared with others received, in order to ensure that the company obtains the best value for the project dollars available. Large projects are often broken down in subprojects based on the associated trades (site preparation, both civil and structural, equipment fabrication and erection, electrical and controls). Each subproject specifies what the supplier will provide, based on the provided specifications and what the owner will provide in order for the supplier to meet its guarantees.

As can be seen, everything in the pollution control project must fit together. If something is left out of the scope, or does not match up with other sections in the scope, the project could be delayed beyond the compliance date resulting in a Notice of Violation (NOV) for non-compliance. The risk of not meeting environmental performance requirements and the possibility of NOVs add a high degree of value and urgency to the equipment proposal evaluation relative to the permitting process. Equipment/Supplier guarantees are critical to the ongoing permitting process.

A company will typically hire an Architect/Engineer firm (A&E firm) for its expertise in bringing these systems together and assuring that the subprojects fit together properly and performance guarantees can be met. The A&E firm begins evaluating the responses to the RFP, especially the basis for guarantees provided and performance experience of each bidder. This usually places new and developing technologies at a significant disadvantage, as companies tend to avoid taking risks on new technology for pollution control projects required by new regulations.

To illustrate the points, we will take the case of a retrofit dry scrubber, followed by a baghouse, at a coal-fired boiler. A dry scrubber is appropriate equipment for a

[3] For an excellent primer on the detailed design stage of an industrial energy/environment project, See *The Guide To Low Emission Boilers and Combustion Equipment Selection* (ORNL/TM-2202/19), by C.B. Oland of Oak Ridge National Laboratory for DOE with CIBO and the American Boiler Manufacturers Association (ABMA). Produced in 2002, it is pre-Boiler MACT and does not include additional MACT requirements for new and existing projects. Available at www.cibo.org .

manufacturing plant needing to reduce acid gases including SO2 and HCl. For such an installation the costs would cover at least these elements:

- Purchase and fabrication of the scrubber and baghouse components
- Civil engineering and site preparation
- Foundations and concrete
- Lime receiving and preparation
- Byproduct processing and storage
- Instrument, piping and controls
- Architect/Engineer
- Construction and installation
- Other, including electrical supply

The total estimated initial budgeting project cost in a retrofit scrubber installation project covering these elements could vary significantly depending on many factors, including the number of boilers, the size of the facility, and the level of difficulty of the installation.

Following evaluation of the proposals, the company selects a winning supplier or suppliers, finalizes contract costs pending potential escalation due to material, labor and shipping from project delays for any reason, signs contracts with suppliers and the project moves forward to installation.

Equipment Fabrication, Construction and Installation

With contracts in hand, suppliers can then complete detailed engineering drawings. Based on these detailed engineering drawings, the requirements are identified for everything needed to complete the installation, including site work, instruments controls, wiring, piping, ductwork, structural steel, fans, pumps, motors and their support systems, and anything else needed for a seamless interconnection of all contracts, equipment and the owner's facility. This complete scope is sometimes referred to as a turnkey project.

The turnkey project makes a single party responsible for all interconnections, guarantees and scheduled start-up for the total project. This could be the Architect/Engineer, contractor or other third-party management company. Overall project management is critical, especially where different components of the project must interface perfectly. It could be very costly if, for example, the foundation for the scrubber were installed two inches off-spec, and had to be redone. As such, a tremendous amount of oversight is required to manage the overall project, from the initial award of the contracts to the final acceptance of the project. This cost may not be added to the total project cost.

A cost estimate of the entire turnkey project is clearly closer to the total project cost of meeting a new regulatory standard than simply the cost of the control equipment. It could be a good representation of the total capital cost of the emission control requirement for an electric utility facility or a new project with no siting or space limitations, or a "stand-alone" plant. However, for an existing manufacturing or industrial energy facility, every aspect of the project is more complicated and therefore more costly. Connections, the availability of the required utility connections, and space availability can be much more complex, necessitating significant modification and upgrade of existing utilities and equipment. Therefore, a more realistic total capital cost projection for such existing facilities would be based on turnkey installation plus additional costs associated with site and facility complexities and limitations.

Equipment and Process Integration

Most industrial and university energy facilities are old. Very few new facilities have been built in the United States in the last ten to fifteen years. Instead, existing facilities have been expanded and modified to meet new energy demands created by growth. In part because of increasing global competition and pricing pressures, these plants often do not have sufficient excess capacity for adding new control equipment. This adds to the complexity and cost of retrofitting pollution control equipment to an existing facility. In some cases, the "shoe horn" is not good enough, meaning that some demolition and removal of existing structures or equipment is required, along with additional structural steel, to make way for new control equipment installation.

While every industrial and university energy facility is different, they all have one thing in common: they must provide energy to their customers (campus buildings or a manufacturing process) to support day-to-day operations. It is generally not possible to shut down the manufacturing plant or university during construction and installation of pollution control equipment. There is no independent source of power to run the plant during construction and equipment tie-in. Rental boilers, while expensive, may be an alternative, but add significantly to the cost of the overall project.

Thus, the construction project schedule must integrate with the demands of the customers to provide the shortest outage time possible with the least amount of service disruption. The added labor costs associated with overtime or night shift work required to work around normal facility operations can be substantial and may not be considered in the initial estimates of the project costs.

The owner incurs additional costs to supply support services and interconnections to the turnkey project. Each of these installations or services must meet detailed specifications to assure the schedule and guarantees can be met. Each adds significant cost to the project that may not be reflected in the turnkey or final capital cost of the project.

Returning to the example of the retrofit scrubber and baghouse, if it is installed at an existing facility, the list of requirements for installation has now grown to include:

- utility connection for water, used to scrub the flue gases
- utility connection for compressed air
- fuel and flue gas
- lime to actually capture the emissions
- rental of space to locate construction trailers and equipment

- secure area accessible to the construction site for receipt and temporary storage of parts and materials (if industrial site space is at a premium, that increases the overall cost of the project.)
- electricity to operate pumps and motors for water supply and scrubber
- electricity to run the fan and motors to move the flue gas through the scrubber to the stack and the byproducts out to storage or disposal
- system upgrades, modifications or replacement for the older facility not designed to handle additional load

Because total plant needs are considered along with the potential for applicable regulations, these elements can have a greater impact on the overall costs of the emission control equipment. And if the upgrade, modification or replacement benefits more than emission control equipment, it may not be included in the total turnkey cost of the project. As such, it may be capitalized with the project.

The availability of electricity is often taken for granted. However, many industrial and institutional facilities must purchase electricity from their local utility, and may be limited in their ability to handle the added requirements for the numerous large pumps, motors, and fans required for the project. This could require a new electric substation to handle the load. In most cases, these incremental increases in plant electric capacity are not considered in the cost of pollution control systems used by regulators, and these costs may not be capitalized with the turnkey project costs.

In the case of the scrubber and baghouse, the actual interconnection with the existing equipment will normally require a plant outage. If this can be timed with a planned maintenance outage, all is well and good. However, should interconnection require a separate outage, the owner faces lost production and significantly increased costs. The lost revenues and costs are not normally considered when the total turnkey project costs are developed for regulatory cost consideration.

In summary, each plant and installation is different and, as such, the cost of the pollution control equipment alone is not representative of the total capital cost of the project required to reduce emissions and meet revised environmental requirements.

Training, Start-up, Testing, Monitoring and Reporting

As the project nears completion, the plant operations become involved. On-site support from the suppliers’ start-up engineers and service personnel are normally included with the equipment contracts. However, training time and any equipment required for training the plant operators and maintenance staff on the new equipment are separate costs. Depending on the complexity of the equipment and new processes, these could be substantial and beyond normal workload requirements, requiring overtime – an added project cost that agency estimates typically to not take into account. To minimize the costs associated with the various training requirements, much of the training will take place during the start-up and testing of the equipment, generally as "on-the-job" training provided by the equipment suppliers' start-up personnel.

A pollution control project must undergo two types of testing. The first is performance testing, or acceptance testing. This is undertaken by the suppliers and is typically included in the base contract cost. During this testing, technical glitches are uncovered. Repairs and/or modifications to operating components may be necessary and these may not get allocated to the cost of the project.

The second type of testing required is emission performance testing, or compliance testing, required by state and federal laws for the final operating permit, and to assure compliance with the emission regulations. Many facilities are required to have Continuous Emission Monitoring systems (CEMs) installed to demonstrate on-going, continuous, compliance with the regulations. Typical agency cost estimates associated with CEMs include only the capital cost of the monitoring equipment and underestimate the complexity and cost of the installation. A common complicating factor with CEMs is limited locations for the sample probes that meet EPA requirements, meaning that the sample probe must be located at the exhaust stack. This may require the installation of a stack platform, as well as OSHA-compliant access, in addition to numerous ports and flanges for equipment siting. Installation costs are a critical component of the pollution control project and should be calculated by the agency as part of capital cost, where proof of on-going compliance is required by the regulations.

Once a CEM system is installed and operational, many tests are required to demonstrate the accuracy of the system, as defined by EPA. There is very little difference in the cost of testing any emission control device, whether it is located on a large utility boiler or small industrial/institutional source. This is especially true of the CEM equipment installed. For some small industrial facilities, the installed cost can be nearly as much as the emission control equipment itself, regardless of the fact that there are no direct emission reduction benefits from the equipment. Monitoring equipment and installation on any emission control system, if required, should be included within the total project cost and included in any regulatory cost evaluation for the industrial facility.

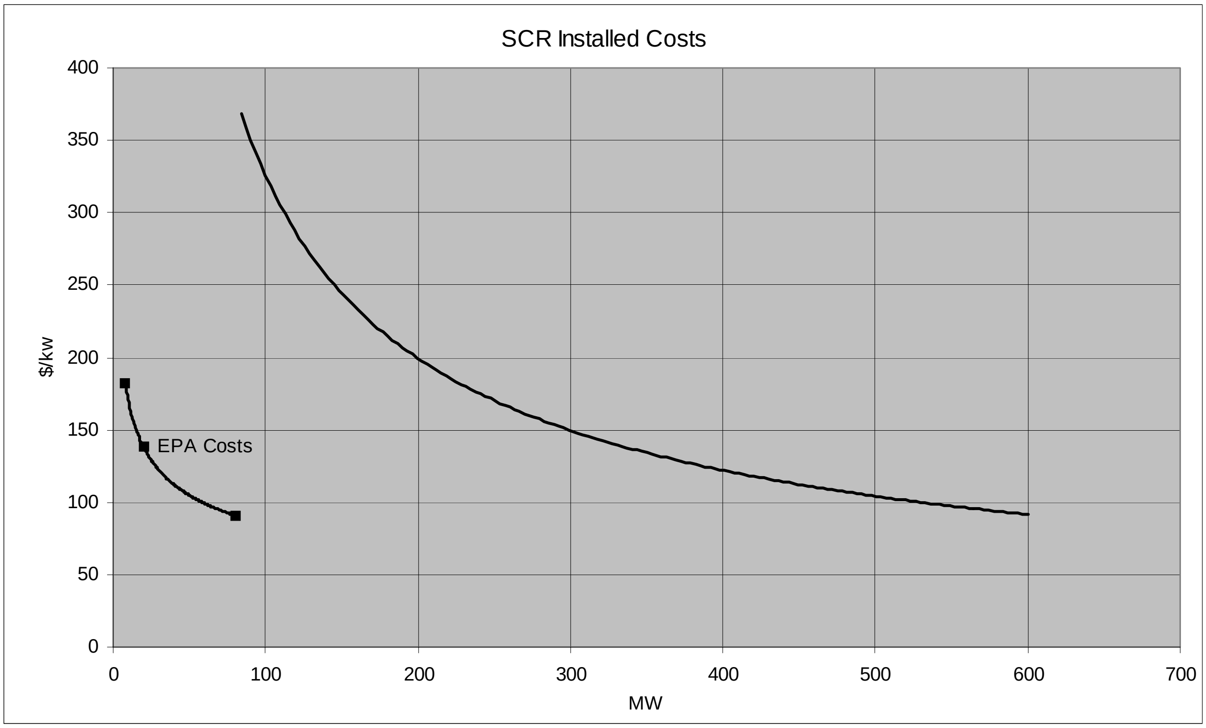
Also unaccounted for are costs associated with required electronic reporting to state and federal agencies and for a dedicated computer system for data acquisition to support the reporting. As with other unaccounted-for costs, this adds to the capital cost of any pollution control project and emissions reduction requirement.

Attachment C provides additional examples of site-specific conditions that can significantly increase the costs of retrofit pollution control equipment installation.

CONTROL EQUIPMENT COST REPRESENTATIONS

CIBO members have years of experience with retrofit pollution control equipment In order to more specifically understand the gap between agency cost estimates and real world costs of pollution control projects, CIBO requested that Black & Veatch analyze completed projects and their estimated and real costs. The results of that study are included here as Attachment A. Reproduced below is one graph from the study, a concrete demonstration of why the true capital cost of an industrial energy facility pollution control project is not adequately accounted for in agency cost estimates. This graph confirms CIBO members' observation that as project size decreases, the costs associated with the project increase exponentially.

The following graph taken from the Black & Veatch study represents the estimated and actual costs of installing on an 80-megawatt unit a selective catalytic reduction ("SCR") system, designed to remove nitrogen oxides from the flue gas. As the lines indicate, EPA had estimated the emission reduction project would cost $90/kw of emissions reduced, whereas the true cost was $370/kw of emissions reduced -- a fourfold increase.



The study provides additional data that helps explain why estimate gaps exist. This data could be used as a basis for improving the quality of project cost analysis and decision-making for environmental regulations.

SUMMARY

There is some art, but mostly science and engineering, to projecting the total cost to an industrial facility to make necessary facility changes and install emission control equipment to meet new regulatory standards. The process itself is lengthy, costly and includes many cost elements that are not accounted for in standard cost estimates prepared by agencies.

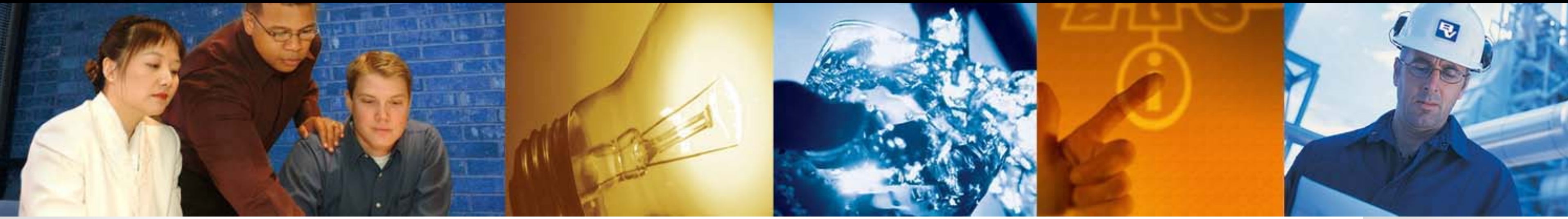
During the rulemaking process, regulators rely on what they believe to be the best information available to predict the economic impact a proposed regulation on the regulated community. Often that information reflects only a fraction of the cost (perhaps the cost of the equipment alone) and does not reflect the associated costs that form the greater portion of the total capital cost of the upgrade. In other cases, costs are extrapolated from cost data for completely unrelated facilities, such as new facilities or electric power generation facilities. Neither provides a good basis for estimating the cost of equipment upgrades to an existing industrial facility with siting, energy supply, process control and multiple other complications.

The ultimate goal of pollution control retrofit project is a facility approved and accepted for normal operation. At that point, the plant assumes the equally burdensome ongoing operation and maintenance costs. O&M costs are even more critical when evaluated relative to the global competitiveness of the company and what it produces, as well as in determining overall costs of emissions control. O&M costs are considered within the initial planning and permitting stage of project development to determine whether a project is economically feasible and the optimum path forward, but rarely are O&M costs considered by the agencies on the same order of magnitude. Our focus here has been on the capital cost of completing a pollution control project, but that tells only part of the story.

ATTACHMENT A

BLACK & VEATCH

WE BRING IT ALL TOGETHER



Industrial Vs. Utility Emissions Control Equipment – Analysis of EPA Methods, Assumptions, References and Costs

Presented by Doug Friedel, P.E.

Prepared by Jeff Arroyo, P.E.

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ENERGY WATER INFORMATION GOVERNMENT

December 7, 2005

Purpose and Objective

- Review EPA Methods, Assumptions and References for Cost Estimates
- Compare EPA Cost Estimates to B&V Estimates
- Other Issues and Concerns

EPA Analysis

- Focused on SO_2 and NOx Control Only
- 100, 250 and 1,000 MMBtu/hr Coal-Fired Boilers
- Followed DOE Design Handbook for Duct Injection, Semi-Dry and Wet FGD, EPA CUECost Program, EPA IPM, EPRI Economic Guidelines & Technical Assessment Guide and Vendor Budgetary Quotations
- Costs Stated in 1999 Dollars

EPA Cost Calculation Assumptions

- Establish Design and Performance Parameters
- Estimate Direct Capital Costs Based on Budgetary Quotations and Study Estimates
- Indirect (Non-Process) and Contingency Costs of 20% and 15%, Respectively.
- Includes a 30% Total Cost Retrofit Factor
- No Allowance For Owners Costs (i.e., IDC)
- Uncertain How Differential O&M and Levelized Costs Were Calculated

EPA Analysis – SO_2 Controls

- In-Duct Dry, Semi-Dry and Wet FGD Systems
- Existing ESP Used for Particulate Capture
- Included Additional Ash Handling and Aux Power Reqt's
- Solid Waste Generated Disposed in Landfill (No Sales)
- Lime (dry and semi-dry) and Limestone (wet) Reagents
- Assumed 83% Capacity Factor
- Accounted for Some BOP Impacts, but Not All

Other Assumptions – SO_2 Controls

	% Sulfur	Heating Value, Btu/lb	% Reduction
In-Duct Injection	2.0	11,922	40
Spray Dryer Absorber	1.8	9,000	90
Wet FGD	2.5	11,922	90

EPA Estimated Costs – SO_2 Controls

	100 MBtu/hr	250 MBtu/hr	1,000 MBtu/hr
In-Duct Injection			
$/MBtu/hr	17,995	12,987	8,648
$/kW Equivalent	225	162	108
$/ton	1,075	849	697
Spray Dryer Absorber			
$/MBtu/hr	54,679	36,226	20,275
$/kW Equivalent	683	452	253
$/ton	790	569	381
Wet FGD			
$/MBtu/hr	59,598	45,283	29,888
$/kW Equivalent	745	565	374
$/ton	836	661	461

B&V Findings – SO_2 Controls

- Flue Gas Temperatures for Industrial Applications Typically Much Higher (350 to 450F Versus 285F)
- O&M and Levelized Annual Cost Calculations Appear to Follow Standard Economic Guidelines
- Capital Costs Developed From EPA Models, Engineering Studies and Budgetary Quotations
- Costs for In-Duct Injection and Wet FGD for all MBtu/hr Cases Appear Reasonable.
- Costs for Spray Dryer Absorber for all MBtu/hr Cases are Low (Excludes New Downstream Particulate Control Device)

B&V Findings – SO_2 Controls (Cont.)

- EPA Assumed Low Removal Efficiency for Wet FGD (90% Versus 95 to 98%)
- Coal Quality Data Among Control Alternatives Inconsistent
- Constructability and Some BOP Costs Excluded
- Owners Costs Not Included (Owners Engineering, Admin, IDC, etc.) – Ranges from 5 to 30%

EPA Analysis – NOx Controls

- Low NOx Burners (LNB), Overfire Air (OFA), Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR)
- Assumed 5 ppm Ammonia Slip, 6” Pressure Drop and Catalyst Replacement Every 3 Years
- Anhydrous Ammonia (SCR) and Urea (SNCR) Reagents
- Assumed 83% Capacity Factor
- Accounted for Some BOP Impacts, but Not All

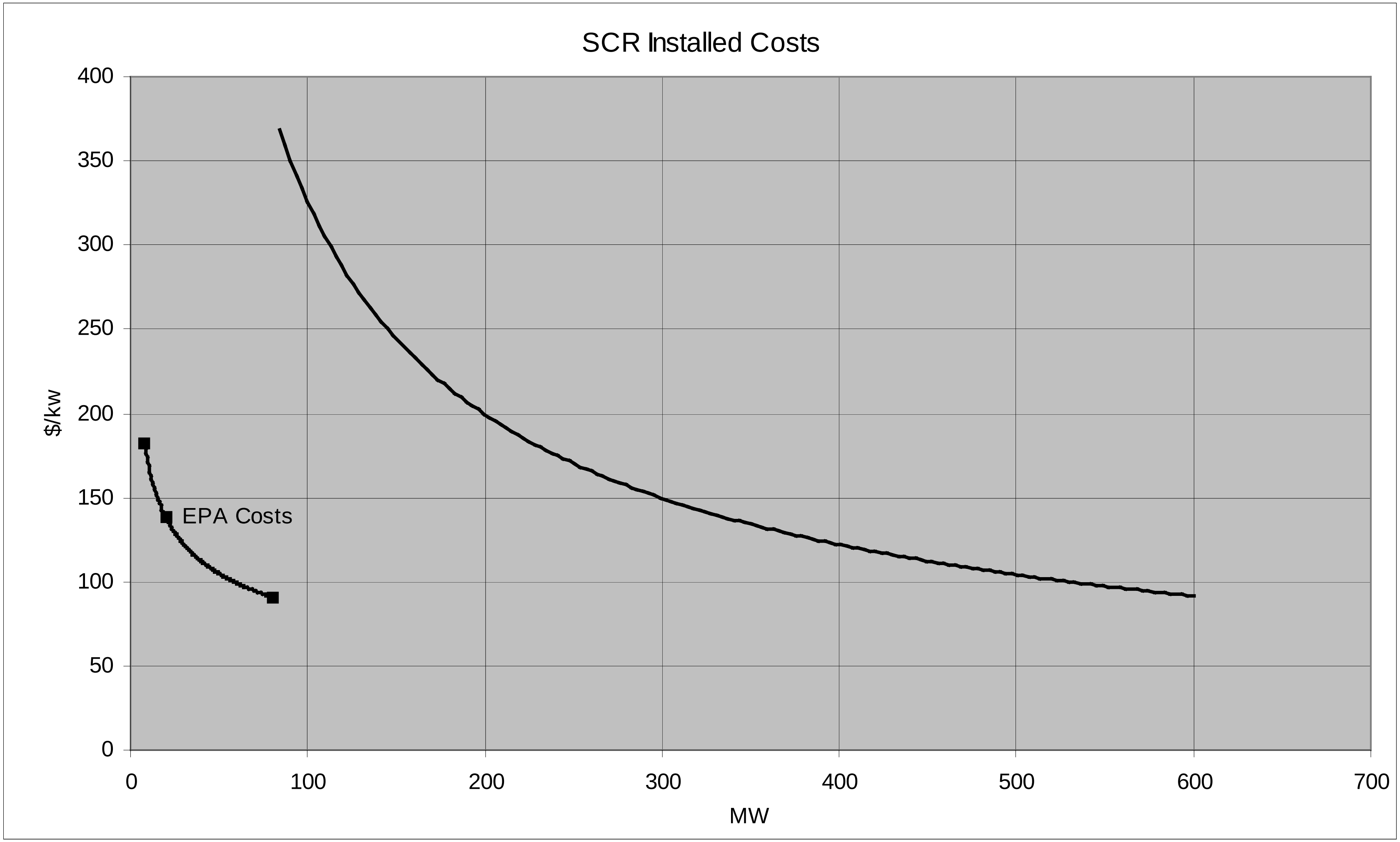
Other Assumptions – NOx Controls

	Inlet NOx Emissions	Outlet NOx Emissions	% Reduction
LNB and OFA	.72	.35	40
SNCR	.72	.43	51
SCR	.72	.14	80

EPA Estimated Costs – NOx Controls

	100 MBtu/hr	250 MBtu/hr	1,000 MBtu/hr
LNB and OFA			
$/MBtu/hr	7,281	5,531	3,649
$/kW Equivalent	91	69	46
$/ton	757	581	392
SNCR			
$/MBtu/hr	5,266	4,000	2,639
$/kW Equivalent	66	50	33
$/ton	1,625	1,473	1,285
SCR			
$/MBtu/hr	14,562	11,062	7,298
$/kW Equivalent	182	138	91
$/ton	1,349	1,123	1,876

SCR Installation Costs – B&V Experience



WE BRING IT ALL TOGETHER

B&V Findings – NOx Controls

- O&M and Levelized Annual Cost Calculations Appear to Follow Economic Guidelines
- Capital Costs Developed From EPA Models and Engineering Studies Only
- Costs for all NOx Controls for all MBtu/hr Cases Are Low, Especially SCR
- EPA Assumed Low Removal Efficiency for SCR (80% Versus 90%)
- Constructability and Some BOP Costs Excluded
- Owners Costs Not Included (Owners Engineering, Admin, AFDC, etc.) – Ranges from 5 to 30%

EPA Estimated Costs – Summary

	Capital Cost Estimates	Emissions Removed	Levelized $/ton
In-Duct Injection	Good	Good	Good
Spray Dryer Absorber	Low	Good	Low
Wet FGD	Good	Low	Low
LNB and OFA	Low	Good	Low
SNCR	Low	Good	Low
SCR	Very Low	Low	Very Low

Ratings: High, Good, Low, Very Low

B&V Findings – Other Issues

- Why Focus on NOx and SO_2?
- MACT Driven HCL, PM and Hg Limits - Major Concern
- BART and Facilities Located In Non-Attainment Areas?
- SCR's and Wet FGD Systems for Small Industrial Boiler Applications < 1,000 MBtu/hr?
- Not Sure All Process and BOP Costs (Including Installation) are Included In All Estimates
- Many Industrial Sites Severely Constrained Due to Limited Real Estate – Is 30% Retrofit Factor Enough?
- EPA Direct Cost Estimates are Low. What's Missing?

Industrial Boiler MACT Rule

- Large Existing Solid Fuel Fired Industrial Boilers
  - PM: 0.07 lb/mmBtu or TSM: 0.001 lb/mmBtu
  - HCl: 0.09 lb/mmBtu
  - Hg: 9 lb/TBtu
- Compliance Date: September 13, 2007
- Other NOx and SO_2 Regulations That Could Affect Industrial Boiler Owners
  - BART Eligible Units (1962 – 1977)
  - Units Located Near Non-Attainment Areas
  - CAIR

Industrial Boiler Unique Characteristics

- Many Industrial Sites Have Limited Emissions Control Equipment and Performance of Existing Equipment is Often Poor
- Typically, Low Capital Cost Technologies with Low Removal Efficiency are Needed
- High Flue-Gas Exit Temperatures Are a Concern for Hg and PM Control
- Available OEM's and Labor Supply for Smaller Installations are Constrained in Today's Market
- Materials of Construction in Short Supply

Other Considerations

- Fuel Switching, Blending and Repowering
- Constrained Site for Construction & High Retrofit Costs
- Combustion Modifications (i.e., Reheat Surface, Economizer Surface, Air Heaters, etc.) and PSD Permitting Ramifications
- Space Limitations for New Control Equipment
- Redundant Equipment Due to High Availability
- Minimal Outage Requirements

Next Steps

- Is Further Analysis Needed?
- Is There Additional Retrofit Cost Data Available From CIBO Members?
- What Does EPA Have to Say About PM and Hg Controls for Industrial Boiler Applications?
- Other Action Items

ATTACHMENT B

DIFFERENCES BETWEEN INDUSTRIAL AND UTILITY BOILERS

Utility and industrial boilers are significantly different. Yet, because both generate steam, legislators and regulators tend to treat them the same.

Major differences between industrial and utility boilers are in three principal areas:
- boiler size,
- boiler steam application, and
- boiler design.

Size

The average new industrial boiler is a dwarf compared to the giant utility boiler. Today's typical utility unit produces 3,500,000 pounds of steam an hour; the industrial boiler 100,000. In fact, most industrial boilers range in size from 10,000 pounds of steam per hour to 1,200,000.

The size of the utility boiler allows it to enjoy significant economies of scale, especially in the control of emissions that simply are not available to the industrial unit.

Smaller industrial boilers are more numerous and tailored to meet the unique needs and constraints of widely varying industrial processes. There are about 70,000 industrial boilers in use today compared to approximately 4,000 utility boilers. Yet, all the small industrial units combined produce only a fraction of the steam compared with large utility boilers. In addition, the nation's utility boilers consume over 10 times as much coal as the industrial boilers.

Industrial units produce less than ten percent of the emissions from the nation's boiler population, but because of their smaller size and uniqueness must pay more than utilities to remove a given amount of emissions.

Steam Application

A utility boiler has one purpose--to generate steam at a constant rate to power turbines that produce electricity. Industrial boilers, on the other hand, have markedly different purposes in different industries. Even at a single installation, application of steam from an industrial boiler can change dramatically with the seasons, when steam or hot water is used for heating, as well as from day to day and hour to hour, depending upon industrial activities and processes underway at a given moment and their demand for steam. The possibility of such widely fluctuating demand for steam in most industrial processes means that the industrial boiler does not, in the great majority of cases, operate steadily at maximum capacity. In general, the industrial boiler will have a much lower annual operating load or capacity factor than a typical utility boiler. As a result, any added control costs have a much greater affect on the final output steam cost.

In contrast, a typical utility boiler, because of a constant demand for steam, operates at a steady state rate close to maximum capacity continuously. This basic difference in operation is reflected in proportionately lower operating costs than is the case for industrial boilers similarly equipped. Even where peaking units operate to meet utility load swings during the days or for seasonal peak demands, the utility units' load swings are more controlled and can be balanced over the complete electric production and distribution grid.

Industrial and Utility Boilers are Different

In the event of unscheduled downtime for a given unit, utility electrical generating facilities have a variety of backup alternatives. Industry, on the other hand, rarely has a backup system for steam generation. Because of the desire to keep costs for steam production as low as possible, industry requires a high level of reliability from its boilers. Industrial boilers routinely operate with reliability factors of 98 percent. Any drop in reliability for an industrial system causes loss in production and related revenues. Combustion and add-on control technologies can interfere with system reliability.

Design

Utility boilers primarily are large field erected pulverized coal, No. 6 oil or natural gas fired high pressure high temperature boilers with relatively uniform design and similar fuel combustion technologies. Industrial boilers, on the other hand, incorporate combustion systems including high pressure and low pressure, large and small, field erected and shop assembled package boilers designed to burn just about anything that can be burned alone or along with conventional fuels. Industrial boilers use many different types of combustion systems. Some of these different designs include many different types of stokers, bubbling and circulating fluidized bed combustion systems, and conventional coal, oil and gas combustion systems. In fact, the designs of individual industrial boilers regardless of fuel or combustion type can vary greatly, depending upon application of steam and space limitations in a particular plant. , On the other hand, facilities at a utility plant are designed around the boilers and turbine(s) making application of emission controls significantly more cost effective.

Conclusion

Differences between industrial and utility boilers are major. These differences warrant separate development of laws and regulations that apply to each. Treating them both in the same fashion, simply because they both generate steam, inevitably results in unfair and inappropriate standards.

Accordingly, the Council of Industrial Boiler Owners believes that government should recognize the basic differences between industrial and utility boilers and should tailor requirements to their individual natures and to the unique situations within which each operates.

ATTACHMENT C

EXAMPLES OF SITE-SPECIFIC CONDITIONS THAT SIGNIFICANTLY INCREASE PROJECT COST

The following are examples of site-specific conditions that can significantly increase installed project cost for retrofit of emissions control projects to existing industrial boilers. Each example would present complications to equipment arrangement and installation that would require engineering time and additional cost to work around. In each case, the equipment and associated cost would be increased, and that increase would be magnified as the costs are cumulatively factored for project cost calculation (multiple percentage additions to the cumulative subtotals).

- Inadequate breeching space for installation of an opacity monitor or other CEM, necessitating installation in the stack. Stack installation would require penetrations for the mounting as well as reference method test ports in a concrete stack with brick liner and installation of platforms and ladders. The old stack could also have an asbestos based coating on it, necessitating containment and coating replacement.

- Installation of SCR where existing configuration does not provide the proper temperature range for required NOx reduction. This could require removal, installation, or rearrangement of heat transfer surfaces in areas with very limited access and space. This could entail installation above the boiler with revision to the building enclosure. In some cases, the support steel may be inadequate to support the increased equipment weight, so that additional steel and foundations could also be required.

- Installation of a wet scrubber requires disposition of a liquid waste purge stream. This would include neutralization and treatment in the waste water system. In some cases, the existing waste water treatment system on a plant site simply has no excess capacity to handle additional liquid streams. In those cases, it may be required to install totally new additional waste water treatment capacity. Scrubbers also require a water source. Many plants are limited in water supply or may be unable to increase withdrawal. If increased supply is not available, it may be necessary to modify other users in the plant to reduce use and make some water available; such changes may not be included with the emissions control system costs, but rather handled as separate projects.

- Installation of any type of SO_2 scrubber requires significant plan area near the boiler to be controlled. Many existing industrial powerhouses have been incrementally expanded over many years to the point that there is simply no available space for the scrubbing equipment and sorbent preparation system, let alone access for construction equipment and lay down. It may be necessary to move other existing equipment and facilities in order to provide room. These facilities could include fairly simple facilities such as maintenance shops, but could also include electrical substations or air compressors. Any of that equipment and facility relocation is a significant additional cost that is not directly associated with the control equipment, but is just as much a cost to the owner/operator. There could also be underground and overhead piping and electrical cables that will need to be relocated.

- In addition to the above relocations, space limitations may require equipment to be installed more remotely than desired. This would then require longer runs of ductwork, piping (which may require tracing and insulation), electrical cables, and control cables. Total costs rapidly escalate when distances are increased.

- Installation of any type of emission control equipment will require instrumentation and controls. In many cases, existing industrial and institutional boiler facilities are fairly old and utilize outdated control systems and instrumentation that cannot be expanded or replaced in kind. Installation of new equipment then can necessitate installation of new control systems that may need to encompass much of the existing equipment as well as the added emission control equipment instrumentation and controls. Such installations typically include installation of new Distributed Control Systems (DCS) with new human-machine interfaces, new control rooms, new field instrumentation and wiring, and new power supplies. Such installations can be very costly and are triggered by the emissions control installation.

- Emission control equipment requires electrical power for motors, ESPs, and controls. There may not be adequate spare substation or transformer capacity to handle the increased load. It may be necessary to run cable long distances in order to provide adequate supply and to install new electrical equipment. The ability to tie into existing facilities could also be limited.

- Existing ash disposal could be as beneficial reuse. Installation of emissions controls could result in that reuse no longer being viable due to a change in ash characteristics. In that case, not only will ash quantity increase due to the sorbent and SO2 removal quantity, but the method of disposition will likely require landfilling at a higher cost.

- Existing boiler breeching and ductwork may be severely corroded and incapable of reuse with new control equipment. It is possible that full breeching replacement with new insulation may be required. It is also likely that old boiler breeching and boiler insulation contains asbestos. Any work with asbestos is very costly due to containment and abatement requirements.