Discussion of OAQPS Cost Manual Method for AQCS Estimation

The purpose of this document is to explain why the OAQPS Cost Manual is not sufficient for estimating the cost of air quality control (AQC) equipment. This document will first discuss the impact of escalation on the cost of AQC projects. Next, a discussion of the scope items that are missing from the OAQPS cost manual for SCR is included. Finally, a comparison is made between an estimate performed using the OAQPS method and the B&V estimate for PNM San Juan Generating Station (SJGS) BART analysis.

1.0 Impact of Escalation on AQC Costs

The most recent revision of the OAQPS manual is the EPA Air Pollution Control Cost Manual, Sixth Edition, EPA/452/B-02-001, dated January 2002 (the Cost Manual). There have been significant cost increases in AQC equipment since its release. Section 4.2, Chapter 2, Selective Catalytic Reduction, was written in October 2000. In addition to that, on page 2-40, Article 2.4 of the SCR section, it was indicated that the costs presented in the manual are based on 1998 dollars.

In Chapter 2 of the Introduction (Article 2.4.3), the Cost Manual specifically discusses the importance of escalating the cost of equipment to the current year. Costs can and do change dramatically over time. It has been 8 years since the SCR section of the Cost Manual was written, and the reference costs in the Cost Manual are 10 years old. In that time, the AQC industry and the energy industry have seen significant increases in the cost of equipment and construction. The Cost Manual does not take into account the significant increase in demand for equipment, commodities, contractors, and construction labor experienced over the past 9 years from the many retrofits associated with the Acid Rain Program, ozone SIP call, New Source Review (NSR), Prevention of Significant Deterioration (PSD) projects (both new and modifications), the Clean Air Interstate Rule (CAIR) and the BART program, the new coal projects in the US and international markets. Any cost estimate, such as B&V's cost estimate for the BART analysis, must take into account the impact of escalation.

The cost of AQC equipment has increased dramatically over the last few years (2005 to 2007 time frame). Figure 1 is taken from a press release from the Cambridge Energy Research Associates website (the entire press release is included as Reference 1 in Appendix A of this document). This figure shows that between the year 2000 and the year 2007, the refinery industry has seen a 66 percent increase in the cost of implementing large projects. Although this graph is focused on the refinery industry, the electric utility industry uses many of the same vendors, contractors, and raw materials on new power generation projects and AQC projects. As a result, these cost increases are indicative of cost increases being experienced in the electric utility industry.

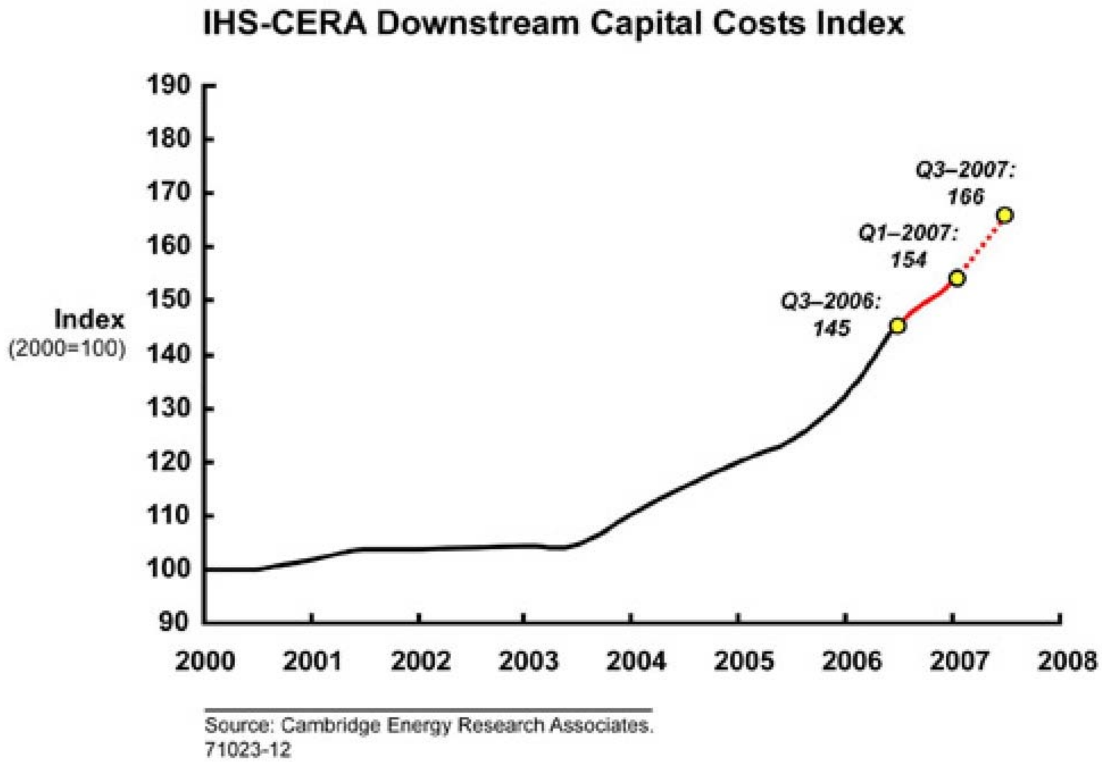


Figure 1

IHS-CERA Capital Cost Index

Another reference that presents the dramatically changing costs associated with AQC projects is a industry paper titled "Current Capital Costs and Cost Effectiveness of Power Plant Emissions Control Technologies" prepared by J. Edward Cichanowicz for the Utility Air Regulatory Group (included as Reference 2 in Appendix A). Mr. Cichanowicz is a well-known utility industry environmental control technology expert who keeps abreast of utility industry environmental control technology trends and costs. He is a former EPRI employee and has produced many publications and presentations for organizations such as Power Engineering magazine and the Electric Utilities Environmental Conference (EUEC). Figure 2 shows a strong example of how the costs of SCR have doubled or tripled since the year 2000. This increase in costs is especially dramatic in the last two years.

The paper describes four "phases" of installation of SCR systems in the US. The first phase is the early SCRs in the US. Phase 2 is the first SCRs installed in response to the OTAG SIP call rules. Phase 3 represents the majority of the SCRs installed in response to the OTAG SIP call. Phase 4 is the current phase. This phase shows very high SCR costs because of the market forces currently impacting the AQC and new generation markets.

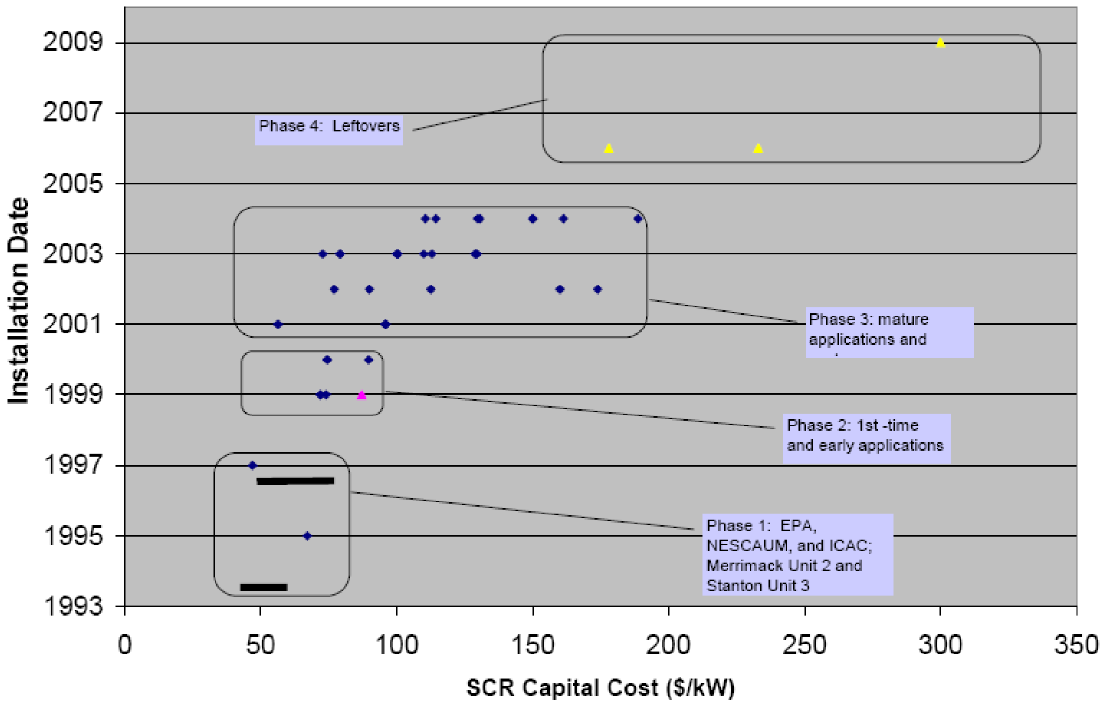


Figure 7-1. Escalation of Cost for SCR Installation with Time

Figure 2

Increases in SCR Costs from Cichanowicz Paper

Figure 3 is data from the U.S. Bureau of Labor Statistics showing the Producer Price Index for metals and metal products. Because SCR systems are comprised mostly of ductwork and structural steel, the increase in price of metal and metal products is a reliable indicator of the price of SCR equipment. It can be seen that the price of metals and metal products has increased by 59 percent between the years 2000 and 2007. It can also be seen that the majority of the escalation has occurred since 2004. This data can be found on Bureau's website at http://www.bls.gov/ppi/home.htm.

Series Id: WPU1017
Not Seasonally Adjusted
Group: Metals and metal products
Item: Steel mill products
Base Date: 8200

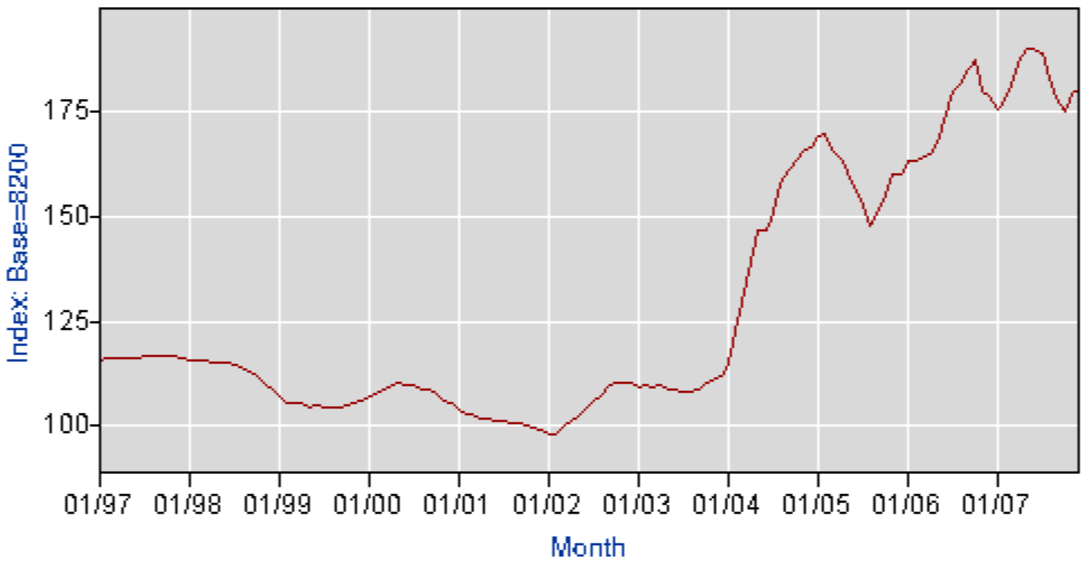


Figure 3

Producer Price Index for Metals and Metal Products

The following quote from a Progress Energy Florida official, Thomas Cornell, is a good description of the price increases that have been experienced by the utility industry: "*the estimated costs of the new air controls have jumped 70% from what was contained in the 2006 filing."There are several reasons for the increase," he explained. "One of the impacts of the final [federal Clean Air Interstate Rule of 2005] was to create significant industry demand for major retrofit construction projects to engineer, procure, and install the necessary air pollution control equipment. This occurred at a time when there was already significant construction activity due, in part, to an improving economy. The situation was exacerbated by even more construction demand in the aftermath of Hurricane Katrina and by the rising demand for steel, concrete and other commodities in countries such as China and India. As a result of these world-wide market conditions, PEF and the industry have seen significant increases in costs for major construction projects, especially for SCR and scrubber equipment and installations. The increases were primarily driven by significant escalation in the cost of basic construction materials* *and in labor costs.*" This quotation is from a June 2007 article in SNLi and can be found at the following website:

http://www.snl.com/InteractiveX/article.aspx?CDID=A-5838501-12640&KPLT=2.

It should also be noted that these cost increases are being experience by the entire industry, not just in the AQC market. New coal generation projects have witnessed significant cost increases over the last few years. A July 2007 article in The New York Times (included in Appendix A as Reference 3) provides the following example: “In late 2004, Duke Energy, one of the country’s largest utilities and most experienced builders, started planning a pair of coal-fired power plants… In May 2005, the company told regulators it wanted to spend $2 billion to build twin 800-megawatt units. But 18 months later, in November 2006, Duke said it would cost $3 billion. Then the State Utility Commission said to build only one of the plants, and in May of [2007], Duke said that would cost $1.83 billion, an increase of more than 80 percent from the original estimate.”

These aforementioned references agree well with B&V’s internal database of costs. Figure 4 presents some of B&V’s estimating department’s internal indexes for various commodities used in SCR applications and other AQC applications. This data is developed by comparing prices in contracts (with similar scope) obtained in 2005 with those obtained in 2007. As can be seen from this figure, prices on various AQC equipment components have increased dramatically in a very short period of time.

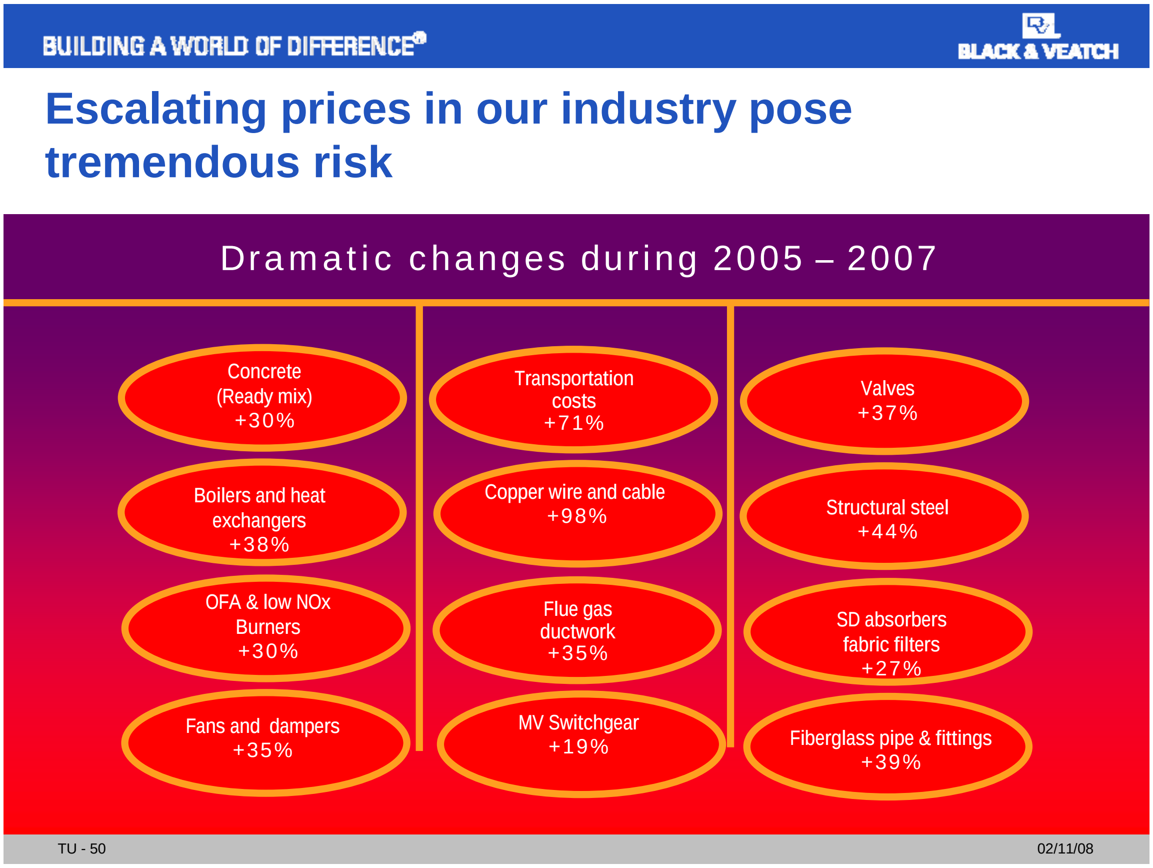


Figure 4

B&V Indexes for AQC-Related Commodities

2.0 Missing Scope in OAQPS Cost Estimate

The Cost Manual presents equations to calculate the components of the SCR system. The Cost Manual has costs factors developed for the following items:

- Reactor ductwork
- Catalyst
- Ammonia system
- SCR bypass
- Retrofit factor
- General factor for all other equipment

It should also be noted that the Cost Manual is geared more towards developing costs for new units than retrofitting controls on existing units. It was originally written to assist utilities with developing costs for BACT analyses.

The SCR cost estimate included in the Cost Manual is missing several key categories of equipment and construction necessary for SCR systems. At the time of the Cost Manual's creation, the industry severely underestimated the balance of plant impacts of SCR. This is evident by the large number of SCR projects built between 2000 and 2004 that had significant cost overruns.

The missing scope items are identified in this section of the document. It should be noted that this section does not discuss how B&V estimated these items. The details of B&V's estimate will discussions in Section 3.0 of this document.

These missing cost items represent real scope and costs that would be borne by PNM if they were required to install SCR on any or all of the units at SJGS. The following discussion supplements an earlier response submitted to the NMED on September 14, 2007.

2.1 Elevator

PNM requires an elevator for maintenance purposes. This would allow the maintenance staff to move more easily equipment such as catalyst tools and NOx monitoring system supplies (such as calibration gas canisters) to the various SCR access platforms. The elevator is not included in the OAQPS estimate.

2.2 SCR Bypass

Although the OAQPS manual includes a cost factor for SCR bypass, it is not accurate or sufficient for all the costs associated with an SCR bypass. For SJGS, the cost of factor results in a cost of approximately $730,000. This cost does not pay for the cost of more than one damper, let alone the ductwork required for the SCR bypass. The SCR bypass dampers are not itemized in the Cost Manual. As previously stated, the SJGS units start up on fuel oil. As a result, there is a great potential for unburned fuel and unburned hydrocarbons to deposit on the catalyst during startup. Because SCR catalyst is an oxidizing catalyst, unburned fuel and unburned hydrocarbons pose a great risk for fires inside the catalyst. It is recommended that the SCR be bypassed during startup operations.

2.3 NOx Monitoring System

The NOx monitoring system is required to measure NOx before and after the catalyst and is an essential part of the SCR system. The measurement is used to control the ammonia feed to the SCR.

2.4 Electrical Upgrades

Upgrades are required to the electrical systems to incorporate the new SCR equipment into the existing system. The scope of electrical upgrades included additional motor control centers (MCC), variable frequency drives (VFD) controls upgrade and substations.

2.5 Instrumentation and Control System

The SCR for this project would need to be incorporated into the existing distributed control system (DCS). This is a typical requirement for an SCR system retrofit but would not be needed for a new unit SCR because the SCR would simply be included in the new DCS.

2.6 Gross Receipt Tax

B&V takes guidance from EPA's CUECost program in developing the costs of SCR systems. The CUECost program includes gross receipt tax as a standard line item in the cost estimate.

2.7 Freight

B&V takes guidance from EPA's CUECost program in developing the costs of SCR systems. The CUECost program includes freight as a standard line item in the cost estimate.

2.8 Air Preheater Modifications

The air heater needs to be modified to make it resistant to ammonium bisulfate (ABS) corrosion and plugging. Ammonium bisulfate is formed from the reaction between sulfur trioxide in the flue gas and ammonia slip from the SCR process. ABS is a sticky, highly corrosive substance that will condense on the "cold end" air heater baskets. The modifications to the air heater include installing new, enamel-coated baskets in the air heater and installing multi-media soot blowers. This will help to minimize plugging from ammonium bisulfate and make the air heater easier to clean. The multi-media soot blowers are used to clean the air heater. The soot blowers use air or steam during plant operation and water during outages to wash off accumulated ammonium bisulfate.

2.9 Balanced Draft Conversion

As previously discussed in PNM's September 14, 2007 submittal, a balanced draft conversion is required for the SJGS. If the SCR is added, the "zero pressure point" of the draft system would move into the region within the boiler. A balanced draft conversion will include stiffening of the boiler and modification to the fans of the draft system.

2.10 Site Preparation

As previously stated in PNM's September 14, 2007 submittal, site preparation is a lump-sum estimate for required site work such as modifying underground facilities, moving buildings, etc.

2.11 Buildings and Enclosures

An enclosure is required around the ammonia storage system for safety and ammonia containment.

2.12 Engineering

B&V takes guidance from EPA's CUECost program in developing the costs of SCR systems. The CUECost program provides a more accurate method for calculating the cost for engineering services than does the OAQPS Cost Manual.

2.13 Contingency

B&V takes guidance from EPA's CUECost program in developing the costs of SCR systems. The CUECost program allows contingency costs to be calculated as 20 percent of the direct capital costs. B&V used this method of calculating contingency instead of the OAQPS method of using 15 percent.

2.14 Owner Costs

PNM would incur a significant amount of costs to install an SCR system. Owner's costs include items such as staff for site coordination during construction, equipment receiving, contract management, interface with regulatory agencies, and owner engineering costs.

2.15 Construction Management

This item is applicable to both new units and retrofit units. However, with new units, the costs for construction management are difficult to identify because the AQC systems are a portion of the overall project. However, on an AQC retrofit project, all construction management expenses are attributed specifically to the AQC retrofit. Construction management costs include the cost for engineering support, construction oversight by PNM or their engineer, environmental services, secretarial services, safety personnel, quality assurance personnel, drug testing, and other services required to ensure that the construction is performed in accordance with the scope of work, safe work practices, regulatory requirements, construction instructions, construction drawings, and vendor requirements.

2.16 Construction Indirects

Cost items included in construction indirects include construction equipment, construction contractor overhead and profit, tools, site trailers and utilities, construction supervision, and construction contractor administrative support. The Cost Manual does not address these costs in any way yet these are real costs that will be incurred in order to support the direct cost of installing the SCR system.

2.17 Startup and Spare Parts

This item includes costs for startup such as development of startup procedures, pre-startup safety review, startup equipment, startup operators, field technical services from vendors, and operations and maintenance training. Spare parts are also included in this category.

2.18 Performance Test

The performance testing is done to demonstrate compliance with permits and to demonstrate that contractual guarantees have been met.

3.0 Comparison of B&V Cost Estimate to Cost Manual Estimate

In NMED's December 21, 2007 letter to PNM, the NMED requested that the cost estimate for SCR be performed using the OAQPS Cost Manual. Sections 1.0 and 2.0 of this document were written to explain why B&V did not use the Cost Manual to prepare the estimate for the SJGS BART analysis. As previously stated, there are two main reasons that the Cost Manual was not used. First, the price of SCR systems (and other AQC retrofits) has increased dramatically in the past 10 years, and especially since 2005. Second, the Cost Manual does not include many categories of equipment and construction that are required for the complete installation of an SCR system consistent with common industry practices. While it was representative of industry knowledge of SCR systems in October 2000, the Cost Manual no longer provides an accurate estimate of the actual cost of SCR. Therefore, B&V developed a cost estimate for the SJGS BART analysis based on an internal database of costs for recent SCR projects. Where possible, B&V scaled the costs from actual vendor quotations from another representative project.

However, in order to respond to NMED's request, B&V has performed a cost estimate using the Cost Manual for SJGS Unit 3. Figure 5 shows the results of that analysis. In this analysis, B&V did not add any of the necessary scope items that are missing from the Cost Manual program as described in Section 2.0 to the estimate. However, in accordance with Chapter 2 of Introduction, B&V did escalate the costs developed from Cost Manual to 2007 dollars. We used the CERA cost index shown in Figure 1 of this document. After incorporating the escalation, we then compared the Cost Manual estimate to B&V's estimate ***<u>FOR A SIMILAR SCOPE</u>***. The results show that B&V's estimate is very similar and on the same scale to the estimate developed from the Cost Manual.

Cost Parameter	Variable Name	Multiplier	Equation	(1998 $) Cost Amount	Escallation to 2007	B&V Estimate	Comments
Total Direct Capital Costs	**A**		**DCC**	**22,327,000**	**37,063,000**	**38,345,000**	
Indirect Installation Costs							
General facilities		0.05	A	1,116,000	1,853,000	1,917,000	
Engineering and home office fees		0.1	A	2,233,000	3,706,000	2,684,000	B&V used 7%
Process contingency		0.05	A	1,116,000	1,853,000	1,917,000	
Total Indirect Installation Costs	**B**		**0.05A + 0.10A + 0.05A**	**4,465,000**	**7,412,000**	**6,518,000**	
Project Contingency	C	0.15	(A+B)	4,018,800	6,671,000	8,973,000	B&V used 20%
Total Plant Costs	D		A + B + C	30,811,000	51,146,000	53,836,000	
Allowance for Funds During Construction	E		=0 (for SCR - OAQPS)	0	0	0	
Royalty Allowance	F		=0 (for SCR - OAQPS)	0	0	0	
Preproduction Cost	G	0.02	(D+E)	616,000	1,023,000	1,077,000	
Inventory Capital	H		ICC	129,000	129,000	129,000	
Initial Catalyst and Chemical	I		=0 (for SCR - OAQPS)	0	0	0	
Total Capital Investment	**TCI**		**D + E + F + G + H + I**	**31,556,000**	**52,298,000**	**55,042,000**	

For Similar Scope, the Cost Manual Estimate and B&V's Estimate are very similar

Figure 5

SJGS Unit 3 - Comparison of Cost Manual Estimate to B&V Estimate

Not Including the Necessary Scope Missing from Cost Manual

However, the estimate shown in Figure 5 is not correct. It does not include cost items that are necessary and appropriate to install an SCR system. This estimate does not represent the true costs that would be borne by PNM if they were required to install SCRs at SJGS. It is unacceptable for the NMED to base regulatory decisions on inaccurate costs if those decisions would require PNM to spend a large amount of capital in retrofitting AQC equipment to their unit. Additionally, if an inaccurate cost estimate were to be the basis of a regulatory determination, NMED would not be responsible for the cost overruns and additional incurred project costs, these would fall on PNM. The cost items missing from the Cost Manual are described in detail in Section 2.0 of this document. If these cost items are added to the estimate, the results are shown in Figure 6. The red boxes identify the missing cost items. As can be seen, when the estimate developed using the Cost Manual is adjusted to reflect the true scope of work necessary for installing SCR, the Cost Manual estimate is very similar to B&V's estimate. Since the methodologies in cost development for all the SJGS units are similar, the same conclusion on the accuracy and completeness of a cost estimate based on the Cost Manual will be applicable to the other SJGS units.

Calculation of Capital Investment - OAQPS Method (Adjustment for Missing Scope)

Cost Parameter	Variable Name	Multiplier	Equation	Cost Amount	Escallation to 2007	B&V Estimate	Comments
Equipment Costs	EC					18,331,000	See original est
Installation Costs	IC					20,806,000	See original est
Total Direct Capital Costs from OAQPS	**A**		**DCC**	**22,327,000**	**37,062,820**	**39,137,000**	
Additions for Missing Scope on Direct Installation Costs							
Elevator	J		B&V Estimate Used		1,236,000	1,236,000	
SCR Bypass	K		B&V Estimate Used		10,000,000	10,000,000	
Nox Monitoring System	L		B&V Estimate Used		440,000	440,000	
Electrical Upgrades	M		B&V Estimate Used		484,000	484,000	
Instrumentation and Control System	N		B&V Estimate Used		291,000	291,000	
Subtotal of Missing Direct Capital Cost	CC		J+K+L+M+N		12,451,000	12,451,000	
Gross Receipt Tax	GRT	0.062	0.062 * (EC + CC)		1,848,000	1,908,000	From CUECost
Freight	FR	0.05	0.05 * (EC + CC)		1,491,000	1,539,000	From CUECost
Installation Costs on Missing Scope	IMS	1.135	1.135*(CC+GRT+FR)		17,922,000	18,044,000	
Air Preheater Modifications	Q		B&V Estimate Used		8,685,000	8,685,000	
Balanced Draft Conversion	R		B&V Estimate Used		17,122,000	17,122,000	
Site Preparation	S		B&V Estimate Used		2,000,000	2,000,000	
Buildings & Enclosures	T		B&V Estimate Used		500,000	500,000	
Total Cost of Missing Scope	**MS**		**CC+IMS+GRT+FR+Q+R+S+T**		**62,019,000**	**62,249,000**	
Total Direct Capital Costs with Adjustments	**DCCA**		**DCC+MS**		**99,081,820**	**101,386,000**	
Indirect Installation Costs							
General facilities		0.05	A		1,853,000	0	
Engineering and home office fees		0.1	A		3,706,000	0	
Engineering (B&V Calculation)		0.07	DCCA		0	7,097,000	CUECost method
Process contingency		0.05	A		1,853,000	0	
Total Indirect Installation Costs from OAQPS	**B**		**0.05A + 0.10A + 0.05A**		**7,412,000**	**7,097,000**	
Project Contingency	C	0.15	(A+CC+B)		8,539,000	0	
Project Contingency (B&V Calculation)	CBV	0.2	DCCA		0	20,277,000	CUECost method
Total Plant Costs	D		A+B+C		53,014,000	66,511,000	
Allowance for Funds During Construction	E		=0 (for SCR - OAQPS)		0	0	
Royalty Allowance	F		=0 (for SCR - OAQPS)		0	0	
Preproduction Cost	G	0.02	(D+E)		1,060,000	0	
Inventory Capital	H		ICC		0	0	
Initial Catalyst and Chemical	I		=0 (for SCR - OAQPS)		0	0	
Total Capital Investment	**TCI**		**D + E + F + G + H + I**		**54,074,000**	**66,511,000**	
Additions for Missing Scope on Indirect Costs							
Owner's Costs	OC	0.05	DCCA		4,954,000	5,069,000	
Construction Management	CM	0.10	DCCA		9,908,000	10,139,000	
Construction Indirects	CI		B&V Estimate		25,498,000	25,498,000	
Start-up and spare parts	SU	0.03	DCCA		2,972,000	3,042,000	
Performance Test	PT		B&V Estimate		200,000	200,000	
Total Cost of Missing Indirect Costs Scope	**MICS**		**OC+CM+CI+SU+PT**		**43,532,000**	**43,948,000**	
Subtotal of Indirect Costs	**IC**		**B+C+E+F+G+H+MICS**		**60,543,000**	**71,322,000**	
Interest During Construction	IDC	0.0741	See Note Below		$17,742,000	$19,196,000	CUECost Allows
Lost Generation During Outage	GEN		5 weeks @ 0.06095 $/kWh		23,674,000	23,674,000	
Total Capital Investment with Adjustments	**TCIA**		**DCCA + IC+IDC+GEN**		**201,040,820**	**215,578,000**	

OAQPS Results and B&V Results are comparable

Figure 6

SJGS Unit 3 - Comparison of Cost Manual Estimate to B&V Estimate

Including the Necessary Scope Missing from Cost Manual

4.0 Explanation of B&V Cost Development

NMED's December 21, 2007 letter requests more information on the development of B&V's cost estimate. B&V used a scaled-factor estimate approach when developing the SCR cost estimate. A scaling factor is used in this type of high-level cost estimate by referencing equipment cost from a similar scope SCR project to that at SJGS. In this section, a detailed description on the development of how each equipment cost line item was calculated.

In Appendix C, B&V has included many of the quotations that were used as references for the estimate. Normally, this is not something that B&V is able to do because the quotations are confidential. However, many of the quotations used to develop the SJGS cost estimate were firm bids taken from another project that was performed for a municipality ("reference SCR"). As a result, the project had public bid openings and the proposals are considered public record. It should be noted that some of the identifying information has been redacted to make this information somewhat more difficult for our competitors (and our client's competitors) to easily track. During the development of the SJGS-specific SCR cost based on this reference, the reference SCR project was still in the contract award stage. Several of the equipment cost line items were based on budgetary estimates for the reference SCR project. Since then, firm quote have been obtained for the reference SCR project. While, the numerical value between the firm quotes and budgetary values used in the development of the SJGS SCR have changed slightly, it should be noted that the magnitude of costs are still very similar. B&V's estimate also uses the EPA CUECost program as a guide for some of the costs included in our estimate. B&V has noted in Figure 6 all areas where we use the CUECost method for calculating costs.

As previously stated, the SCR cost estimate prepared for PNM SJGS Unit 3 was based on firm bids from another recent SCR project (currently being built and scheduled to start operating in July 2008). Scaling factors were used to correlate the reference cost to an estimated value if SCR were to be installed at PNM SJGS Unit 3. The type of scaling factor utilized is dependent on the equipment that is being evaluated. Type of scaling factors used includes:

- Unit size (MW).
- NOx removal rate (lb/mmBtu).
- Gas flow rate.

The scaling factors are used in conjunction with a retrofit factor, typically an exponential of 0.6. This retrofit factor accounts for the non-linear relationship between costs and unit size.

Lastly, for several equipment line items, a complexity factor was applied account for the retrofit complexity of PNM SJGS Unit 3. The retrofit complexity was applied on equipment cost line items where cost is very dependent on the retrofit efforts. Generally, if it is expected that it is more complex to retrofit in the SCR components, greater costs should be allocated for it. Such cost categories for the SCR project are; SCR bypass and structural steel.

A summary of the calculation methods and references used are described in the detail in the following subsections.

4.1 Anhydrous Ammonia Injection System

Inputs:

Escalation rate	= 1.03 (1 year to 2007)
Reference cost	= $758,546 (see quotation in Appendix C)
Reference unit size	= 670 MW
PNM unit size	= 544 MW
Reference NOx removal	= 0.34 lb/mmBtu
PNM NOx removal	= 0.30 lb/mmBtu – 0.07 lb/mmBtu = 0.23 lb/mmBtu

Calculation:

$$PNM\ \cos t = escalation\_rate \times reference\_\cos t \times \left[\left(\frac{PNM\_unit\_size}{ref\_unit\_size}\right)\left(\frac{PNM\_NOx\_removal}{ref\_NOx\_removal}\right)\right]^{0.6}$$

$$PNM\ \cos t = 1.03 \times \$758{,}546 \times \left[\left(\frac{544}{670}\right)\left(\frac{0.23}{0.34}\right)\right]^{0.6}$$

$$PNM\ \cos t = \underline{\underline{\$559{,}000}}$$

Notes/Remarks:

Reference cost was based on the total of the unit price breakdown as detailed in Appendix C. Note that final contract award value was $2,945,000 for 2 units ($1,472,500 per unit) for all equipment scope (including common equipment) detailed in Section 4.1 and 4.2.

4.2 Anhydrous Ammonia Vaporization System

Inputs:

Escalation rate	= 1.03 (1 year to 2007)
Reference cost	= $757,808 (see quotation in Appendix C)
Reference unit size	= 670 MW
PNM unit size	= 544 MW
Reference NOx removal	= 0.34 lb/mmBtu
PNM NOx removal	= 0.30 lb/mmBtu – 0.07 lb/mmBtu = 0.23 lb/mmBtu

Calculation:

$$PNM\ \text{cost} = escalation\_rate \times reference\_\text{cost} \times \left[\left(\frac{PNM\_unit\_size}{ref\_unit\_size}\right)\left(\frac{PNM\_NOx\_removal}{ref\_NOx\_removal}\right)\right]^{0.6}$$

$$PNM\ \text{cost} = 1.03 \times \$757{,}808 \times \left[\left(\frac{544}{670}\right)\left(\frac{0.23}{0.34}\right)\right]^{0.6}$$

$$PNM\ \text{cost} = \underline{\underline{\$559{,}000}}$$

Notes/Remarks:

Reference cost was based on the total of the unit price breakdown as detailed in Appendix C. Note that final contract award value was $2,945,000 for 2 units ($1,472,500 per unit) for all equipment scope (including common equipment) detailed in Section 4.1 and 4.2.

4.3 Reactor Box, Breeching and Ductwork

Inputs:

Escalation rate	= 1.03 (1 year to 2007)
Reference cost	= $5,448,557 (see quotation in Appendix C)
Reference gas flow rate	= 3,081,500 acfm
PNM gas flow rate	= 3,082,200 acfm

Calculation:

$$PNM\ \cos t = escalation\_rate \times reference\_\cos t \times \left(\frac{PNM\_gas\_flow\_rate}{ref\_gas\_flow\_rate} \right)^{0.6}$$

$$PNM\ \cos t = 1.03 \times \$5{,}448{,}557 \times \left(\frac{3{,}082{,}200}{3{,}081{,}500} \right)^{0.6}$$

$$PNM\ \cos t = \underline{\underline{\$5{,}613{,}000}}$$

Notes/Remarks:

Reference cost was based on an estimated cost for another project. When the final contract was signed, the price was $9,754,446 for 2 units ($4,877,223 per unit).

4.4 Ductwork Expansion Joints

Inputs:

Escalation rate	= 1.03 (1 year to 2007)
Reference cost	= $360,000 (see quotation in Appendix C)
Reference gas flow rate	= 3,081,500 acfm
PNM gas flow rate	= 3,082,200 acfm

Calculation:

$$PNM\ \cos t = escalation\_rate \times reference\_\cos t \times \left(\frac{PNM\_gas\_flow\_rate}{ref\_gas\_flow\_rate} \right)^{0.6}$$

$$PNM\ \cos t = 1.03 \times \$360{,}000 \times \left(\frac{3{,}082{,}200}{3{,}081{,}500} \right)^{0.6}$$

$$PNM\ \cos t = \underline{\underline{\$371{,}000}}$$

4.5 Catalyst

Inputs:

PNM catalyst volume = 496 m^3

Catalyst unit price = \$6,500 per m^3

Calculation:

$$PNM\ \cos t = PNM\_catalyst\_vol \times catalyst\_unit\_price$$
$$PNM\ \cos t = 496 \times \$6{,}500$$
$$PNM\ \cos t = \underline{\underline{\$3{,}225{,}000}}$$

4.6 Sonic Horns

Inputs:

Escalation rate = 1.03 (1 year to 2007)

Reference cost = \$182,040 (see quotation in Appendix C)

Calculation:

$$PNM\ \cos t = escalation\_rate \times reference\_\cos t$$
$$PNM\ \cos t = 1.03 \times \$182{,}040$$
$$PNM\ \cos t = \underline{\underline{\$188{,}000}}$$

Notes/Remarks:

Reference cost was based on a preliminary quotation. The final contract award value was \$275,022 for 2 units (\$137,511 per unit).

4.7 Elevator

Inputs:

Escalation rate = 1.03 (1 year to 2007)

Reference cost = $1,200,000 (see quotation in Appendix C)

Calculation:

$$PNM\ cost = escalation\_rate \times reference\_cost$$
$$PNM\ cost = 1.03 \times \$1{,}200{,}000$$
$$PNM\ cost = \underline{\underline{\$1{,}236{,}000}}$$

Notes/Remarks:

Reference cost was based on a preliminary quotation. Contract award price was $957,940.

4.8 SCR Bypass

Inputs:

Escalation rate	= 1.03 (1 year to 2007)
Reference cost	= $5,346,050 (see quotation in Appendix C)
Reference gas flow rate	= 3,081,500 acfm
PNM gas flow rate	= 3,082,200 acfm
Retrofit complexity factor	= 1.8

Calculation:

$$PNM\ \cos t = escalation\_rate \times reference\_\cos t \times \left(\frac{PNM\_gas\_flow\_rate}{ref\_gas\_flow\_rate} \right)^{0.6} \times complexity\_factor$$

$$PNM\ \cos t = 1.03 \times \$5,346,050 \times \left(\frac{3,082,200}{3,081,500} \right)^{0.6} \times 1.8$$

$$PNM\ \cos t = \underline{\underline{\$10,000,000}}$$

Notes/Remarks:

The complexity factor used here accounts for the following items needed to complete the SCR bypass: seal air ductwork, damper access platforms, SCR bypass ductwork, SCR bypass support steel, and expansion joints.

4.9 Structural Steel

Inputs:

Escalation rate	= 1.03 (1 year to 2007)
Reference cost	= $5,732,120 (see details in Appendix C)
Reference unit size	= 670 MW
PNM unit size	= 544 MW
Retrofit complexity factor	= 1.5

Calculation:

$$PNM\ \cos t = escalation\_rate \times reference\_\cos t \times \left(\frac{PNM\_unit\_size}{ref\_unit\_size} \right)^{0.6} \times complexity\_factor$$

$$PNM\ \cos t = 1.03 \times \$5{,}732{,}120 \times \left(\frac{544}{670} \right)^{0.6} \times 1.5$$

$$PNM\ \cos t = \underline{\underline{\$7{,}816{,}000}}$$

Notes/Remarks:

Reference cost was based on budgetary estimates of structural steel requirements and commodity prices for structural steel as detailed in Appendix C. The final contract award value was $14,074,040 for 2 units ($7,037,020 per unit).

The retrofit complexity factor used here accounts for the restrictions in the plant layout, the available laydown area, and the potential crane size allowable at SJGS.

4.10 NOx Monitoring System

Inputs:

Escalation rate	= 1.03 (1 year to 2007)
Reference cost	= $427,200 (see quotation in Appendix C)

Calculation:

$$PNM\ \cos t = escalation\_rate \times reference\_\cos t$$
$$PNM\ \cos t = 1.03 \times \$427{,}200$$
$$PNM\ \cos t = \underline{\underline{\$440{,}000}}$$

Notes/Remarks:

Reference cost was based on a preliminary quotation. Final awarded contract was $779,450. The final price also included sampling fans at a price of $17,555 for 2 units.

4.11 Electrical System Upgrade

Inputs:

Escalation rate	= 1.03 (1 year to 2007)
Reference cost	= $532,550 (see quotation in Appendix C)
Reference unit size	= 670 MW
PNM unit size	= 544 MW

Calculation:

$$PNM\ \cos t = escalation\_rate \times reference\_\cos t \times \left(\frac{PNM\_unit\_size}{ref\_unit\_size} \right)^{0.6}$$
$$PNM\ \cos t = 1.03 \times \$532{,}550 \times \left(\frac{544}{670} \right)^{0.6}$$
$$PNM\ \cos t = \underline{\underline{\$484{,}000}}$$

Notes/Remarks:

Reference cost was based on a preliminary quotation. Final awarded contract cost was based on quotations for multiple scope items totaling to $1,431,788 for 2 units ($715,894 per unit) as detailed in Appendix C.

4.12 Instrumentation and Control System

Inputs:

Escalation rate	= 1.03 (1 year to 2007)
Reference cost	= $288,000 (see quotation in Appendix C)
Reference unit size	= 670 MW
PNM unit size	= 544 MW

Calculation:

$$PNM\ \cos t = escalation\_rate \times reference\_\cos t \times \left(\frac{PNM\_unit\_size}{ref\_unit\_size} \right)^{0.1}$$

$$PNM\ \cos t = 1.03 \times \$288{,}000 \times \left(\frac{544}{670} \right)^{0.6}$$

$$PNM\ \cos t = \underline{\underline{\$291{,}000}}$$

Notes/Remarks:

Reference cost was based on a preliminary quotation. Final awarded contract cost was based on quotations for multiple scope items totaling to $1,008,761 for 2 units ($504,381 per unit) as detailed in Appendix C.

4.13 Air Preheater Modifications

For Units 3 or 4, enamel coated, air preheater basket replacement is recommended if an SCR or SNCR is installed. Air preheater modifications for Units 1 or 2 would also be required, but the scope of work will be different since the air preheater type is different than that at Units 3 or 4. Material costs for air preheater modifications were obtained from a budgetary quotation solicited from an air preheater original equipment manufacturer (OEM) specifically for the PNM project. A comparison to a previous project for a confidential client was made to determine the installation price.

The total direct cost is the summation of the material and installation costs. There are one primary air preheater and two secondary preheaters in Unit 3.

		2007 400MW Confidential ($ USD)	2007 544 MW PNM Units 3&4 ($USD)	Reference
PRIMARY	material per unit	n/a	$533,000	Vendor quote
	Installation per unit	$707,000	$961,966	
SECONDARY	material per unit	n/a	$1,030,000	Vendor quote
	Installation per unit	$1,886,000	$2,565,242	
Total materials per unit			$2,593,000	
Total installation per unit			$6,092,000	
Total per unit			$8,685,000	
Notes: 1. Costs exclude contingency and indirects.				

4.14 Balanced Draft Conversion

The attached table shows a breakdown of the cost estimate for a balanced draft conversion of the PNM SJGS Unit 3 system, required if an SCR were installed. The cost estimate was developed based on reference to the project cost of other reference units where B&V performed a balanced draft conversion. A scaling and retrofit factor was used to determine the engineering & material and construction labor costs.

The total direct cost is the summation of the engineering and material, and construction labor costs.

	Reference Unit		PNM Unit 3 or 4	
Balanced Draft Conversion	Engineering & Material	Construction Labor Costs	Engineering & Material	Construction Labor Costs
Boiler				
Stiffening	$1,800,000	$2,545,000	$1,537,000	$1,908,000
Scaffolding	- -	$350,000	- -	$262,000
Insulation & Lagging	$250,000	$1,250,000	$188,000	$1,438,000
Ductwork & Casing Repairs (Allowance)	$545,000	$3,025,000	$182,000	$1,009,000
Air Heater				
Stiffening	$150,000	$350,000	$125,000	$263,000
Electrostatic Precipitator				
Stiffening (Excludes casing repairs)	$512,000	$2,000,000	$416,000	$1,500,000
Insulation & Lagging (Allowance)	$150,000	$750,000	$113,000	$563,000
Electrical/Control Modifications	$285,000	$600,000	$214,000	$450,000
New transformer (subcontract)			$1,000,000	
Fan Modifications				
FD Fans (new motors only)	$440,000	$154,000	$660,000	$116,000
ID Fans	$5,410,000	$1,577,000	$3,600,000	$1,260,000
Miscellaneous Mech Commodities and Inst	$325,000	- -	$325,000	- -
Subtotal			$8,357,000	$8,765,000

Notes:
1. Costs exclude contingency and indirects.

4.15 Construction Indirects

The construction indirects line item was developed based on the total labor costs for the installation of the SCR equipment. In pre-2004, B&V's estimating department found that the total amount of construction indirect costs typically ranged from 50 percent to 60 percent of the total installation labor costs. However, due to the tightening in labor market that has developed since 2005, construction indirect costs have risen to a range of 90 percent to 120 percent. For the cost estimate of an SCR at PNM SJGS Unit 3, it was determined by B&V's estimating department that a construction indirect rate of 100 percent of total installation labor cost best represented the labor market situation. The table below shows B&V's calculation of construction indirects.

		Direct Installation Cost Splits			
Scope of installation	Direct installation costs	Material	Labor	Material	Labor
Foundation & supports	$10,268,000	70%	30%	$7,187,600	$3,080,400
Handling & erection	$13,690,000	0%	100%	$0	$13,690,000
Electrical	$5,134,000	40%	60%	$2,053,600	$3,080,400
Piping	$856,000	40%	60%	$342,400	$513,600
Insulation	$3,423,000			$0	$0
Painting	$342,000			$0	$0
Demolition	$3,423,000	0%	100%	$0	$3,423,000
Relocation	$1,711,000	0%	100%	$0	$1,711,000
Total	$38,847,000				$25,498,400

Construction Indirects = Direct Installation Labor X 100%

= $25,498,400

5.0 Conclusions

This document shows that simply using the OAQPS Cost Manual to develop an estimate for SCR equipment does not result in an accurate estimate of the cost of the SCR. First, the costs in the manual are in 1998 dollars and must be escalated to 2007 dollars. In addition, there were very few SCR's installed in the United States in 1998 and very little industry experience regarding all of the work required to install an SCR system. As a result, the Cost Manual does not include cost items in its scope that are required to install an SCR system. For these reasons, B&V developed a cost estimate based on the experience from previous SCR projects that have been implemented by B&V. Quotations from vendors were used for the cost estimates, where possible, and with B&V's internal estimating methods in other cases.

It should be noted that B&V's estimate is in line with industry information and represents current costs of SCR systems. Consider Reference 2, the paper written by Mr. Cichanowicz and discussed in Section 1.0 of this document. It indicates that the current cost of SCR is between $180 / kW and $300 / kW, where kW references the size of the unit. Most units do not require a balance draft conversion but SJGS would require a balanced draft conversion for each unit. For comparison purposes, if the balance draft conversion cost were to be removed from the cost estimate of the SCRs for SJGS, the cost of the SCR for Unit 3 would be $164,309,000. This is equivalent to $243 / kW. This is exactly in the range of costs for SCRs that are currently being built. It shows again that B&V's costs are representative of the industry at this time. It also further proves that the Cost Manual is not an accurate representation of the costs for an SCR project, without appropriate escalation and adjustments for additional equipment and cost items. As stated before, selection of BART for a unit MUST be based on an evaluation of the real costs for a project, not on the inaccurately low cost estimate developed from the Cost Manual.

Appendix A

References for Cost Indices

Refinery and Petrochemical Plant Construction Costs Reach New High; IHS/CERA Downstream Capital Costs Index Up 8% in Last 6 months to Record 166 Points

NOVEMBER 7, 2007

Print This Page

Related Topics: **Downstream**, **Global**, **Oil**

Cost Drivers Predicted to Continue

Read the IHS/Cambridge Energy Research Associates (CERA) Upstream Capital Costs Index (UCCI) press release.

Press Release

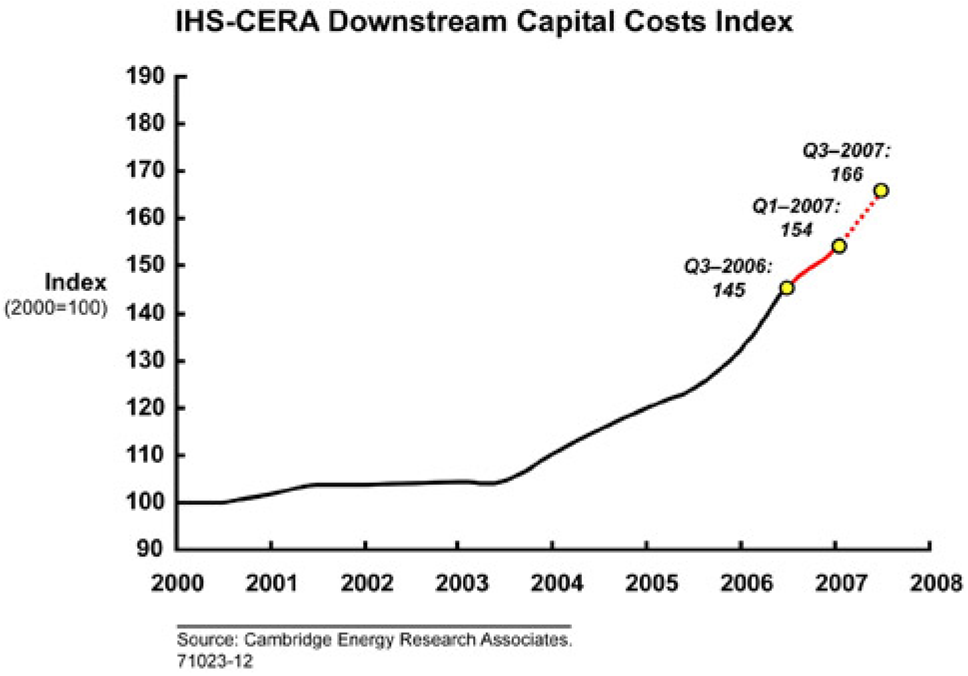
HOUSTON (November 7, 2007) -- The costs of building new oil refineries and petrochemical plants are rapidly rising and reached a new high in the third quarter period ending in October, according to the first release of the new IHS/Cambridge Energy Research Associates (CERA) Downstream Capital Costs Index (DCCI). These costs are beginning to act as drags, leading to delays and postponements in the building of new refineries and petrochemical plants required to keep up with growing world demand.

The new DCCI complements the IHS/CERA Upstream Capital Costs Index (UCCI), which measures the cost of construction of new oil and gas production projects such as platforms and pipelines. Both indices demonstrate the dramatic impact rapidly rising costs are having on the energy industry.

The DCCI registered a high of 166 points in October, indicating an eight percent increase in the last six months in the costs associated with constructing new refinery or petrochemical plants. The DCCI is a proprietary measure of project cost inflation similar in concept to the Consumer Price Index (CPI) It provides a benchmark for comparing costs around the world and draws upon proprietary IHS and CERA data bases and analytic tools.

All values are indexed to the year 2000. Thus, a piece of equipment that cost $100 in 2000 would cost $166 today (see chart).

Downstream facilities are required to turn raw oil and gas into useful end products such as gasoline, heating oil, plastics and fertilizer. As the cost of construction rises, firms may become reluctant to invest in new plants, or delay and postpone these projects thus, in turn, constraining the growth of capacity.



The DCCI has been on an upward trend since 2003 with annual increases in the last three years of seven, 17 and 14 percent, respectively.

“The latest increases have been driven by continued high activity levels globally, continued tightness in the equipment and engineering markets, as well as historically high levels for raw materials” said Jackie Forrest, lead researcher for the Capital Costs Analysis Forum for Downstream, an on-going research project of CERA.

“On a global basis, the refining and petrochemical sector is currently facing heavy strains with new builds in the Middle East and Asia, expansions in the United States and heavy oil projects in Alberta all occurring simultaneously,” Forrest continued.

“We expect global refining capacity to expand 1.7 percent per year for the next five years, adjusted for expected delays and cancellations,” she added.   “This is 20-30 percent more expansion activity per year than we have recorded in the recent past. This may not sound like much, but 1.7 percent growth in refining capacity equals about 1.5 million barrels per day and that is significant as these are complicated facilities to construct.

“As a result of all of this activity, lead times for engineered equipment has increased up to 50 percent in the last 6-12 months for some items, and as expected, prices have increased,” Forrest added. “Further compounding the problem is the raw materials and shipping situation. Both of these sectors have experienced recent increases, ultimately passing through costs to projects.”

Looking forward, Forrest said: “Unless there is a sudden and dramatic change in the industry, activity and market pressures should keep the DCCI at these levels, if not higher, for the next 12-18 months. After that period, there may be a re-balancing of the industry with either fewer active projects or a greater amount of delivery capacity available, or both.”

# # # #

About the IHS/CERA Downstream Capital Costs Index (DCCI)

The IHS/CERA DCCI tracks the costs of equipment, facilities, materials, and personnel (both skilled and unskilled) used in the construction of a geographically diversified portfolio of more than thirty refining and petrochemical construction projects. It is similar to the consumer price index (CPI) in that it provides a clear, transparent benchmark tool for tracking and forecasting a complex and dynamic environment. The DCCI can be tracked on the IHS Index Web Site: **www.ihsindexes.com** . The DCCI is a work product of CERA’s Capital Costs Analysis Forum for Downstream (CCAF-D). For information on the Capital Costs Analysis Forum for Downstream, contact Jackie Forrest at **jforrest@cera.com** or Richard Ward at rward@cera.com

About CERA (www.cera.com)

Cambridge Energy Research Associates (CERA), an IHS company, is a leading advisor to energy companies, consumers, financial institutions, technology providers, and governments. CERA (www.cera.com) delivers strategic knowledge and independent analysis on energy markets, geopolitics, industry trends, and strategy. CERA is based in Cambridge, MA, and has offices in Bangkok, Beijing, Calgary, Dubai, Johannesburg, Mexico City, Moscow, Mumbai, Oslo, Paris, Rio de Janeiro, San Francisco, Tokyo and Washington, DC.

About IHS (www.ihs.com)

IHS (NYSE: IHS) is one of the leading global providers of critical technical information,

decision-support tools and strategic services to customers in a number of industries including energy, defense, aerospace, construction, electronics, and automotive through two operating segments, Engineering and Energy. IHS serves customers ranging from governments and large multinational corporations to smaller companies and technical professionals in more than 100 countries. IHS employs more than 2,300 people around the world.

Reference 2

CURRENT CAPITAL COST AND COST-EFFECTIVENESS OF POWER PLANT EMISSIONS CONTROL TECHNOLOGIES

Prepared by
J. Edward Cichanowicz

Prepared for
Utility Air Regulatory Group

June, 2007

CURRENT CAPITAL COST AND COST-EFFECTIVENESS
OF POWER PLANT EMISSION CONTROL TECHNOLOGIES

SECTION 1

SUMMARY

The utility industry faces numerous mandates to retrofit air emission controls to existing power plants. Specifically, the Clean Air Interstate Rule (CAIR), Clean Air Visibility Rule (CAVR), settlements with the Department of Justice over alleged NSR violations, and the Clean Air Mercury Rule (CAMR) all require retrofit of control technology. Many of these rules and consent decrees require equipment installation and operation on or before 2010, with mandates for more equipment retrofits shortly thereafter. The schedule for this significant emission control retrofit program is coincident with the anticipated construction of approximately 80 GW of new power plants according to some estimates (Figueroa, 2006).

This demand for emission control equipment has strained domestic supply chains. Internationally, robust demand for materials and labor for petrochemical industries, urban infrastructure, and power generation in developing countries consumes much of the international supply. As a consequence, capital cost has escalated for flue gas desulfurization (FGD) and selective catalytic reduction (SCR) equipment, and material/labor shortages force construction delays. Some owners of small generating units simply cannot access control equipment as suppliers are overbooked – some requests-for-proposals for FGD receive no bids, or limited bids at a premium price. These issues complicate, if not prevent, complying with the regulations within the timeframe specified by the regulatory actions.

For example, in the case of wet FGD, prices for components such as electrical transformers, flue gas stacks, and specialty steel pipe have increased 40% and 50% between 2003 and 2007. The price of field fabricated steel tanks, slurry pumps, reagent pulverizers, reagent conveyors, and flue gas booster fans has escalated 15-23% over the same period. The lead time from order to delivery for components such as ball mills for reagent preparation, rubber-lined recycle pumps, fans, and spray headers has more than doubled in many cases.

Consequently, FGD capital cost has escalated at a rate equivalent to 7-9% annually since 2003. The example of Allegheny Energy is instructive – firm bids received in 2006 for wet FGD for Ft. Martin Units 1-2 and Hatfield Ferry Units 3-4 exceeded cost estimates developed in 2004 by an average of $100/kW. This is not an isolated event, and the consequences are significant. For a coal with sulfur content of 6 lbs/SO_2/MBtu, an increase in capital cost of $100/kW can translate into higher SO_2 removal cost effectiveness of several hundred dollars per ton. The same escalation in FGD capital cost for a PRB coal with typical sulfur content of 0.9 lbs SO_2/MBtu will increase SO_2 removal cost effectiveness by $800/ton.

Regarding schedule, under the best conditions a wet FGD retrofit can be completed within 36 months, but only if none of the key suppliers are overbooked for the project duration. This is typically not the case – some constructors and erectors of specialty items are booked for the next 4 years[1]. It should be noted that in 2002 EPA projected that FGD installations for CAIR would require a 28 month schedule from inception to startup (EPA, 2002).

The cost for SCR NOx control has similarly escalated. The most recent reports show SCR capital cost averages $200/kW because the remaining sites to be retrofit present significant challenges. Catalyst unit price has dropped fivefold since the earliest commercial applications, but the increasingly complex sites and escalation in material cost have offset any cost benefits. The cost of ammonia-based reagent, of which 80-90% is determined by the price of natural gas, now averages $400/ton. Reagent cost is now the largest SCR operating cost component.

For a typical 500 MW unit firing an eastern bituminous coal and producing NOx at a rate of 0.38 lbs/MBtu, a $100/kW increase in SCR capital cost will elevate NOx removal cost effectiveness by $800/ton (annual operation). For a 500 MW unit firing PRB and producing NO_x at a rate of 0.20 lbs/MBtu, a capital cost increase of $100/kW will increase NOx reduction cost effectiveness by almost $2,000/ton.

Hg control plans may also be impacted by the supply and demand imbalance. EPA estimates a total of 1,900 MW of fabric filter (FF) capacity will be installed for use with mercury-specific sorbent, such as activated carbon injection (ACI) to meet CAMR by 2010 (EPA, 2006). The basis of EPA's estimate is not revealed, and it is not possible to judge how realistic this prediction is. Based on the emissions control rule proposed by the state of Georgia, it is likely the actual installed inventory of FF retrofit will be greater than predicted by EPA's analysis, which did not consider state-specific Hg regulations. Finally, EPA assumptions of co-benefits of Hg removal by SCR and FGD may be optimistic, especially for those applications involving low rank coals. These short-falls in Hg removal would then have to be compensated for by greater control by ACI with FF.

In summary, the converging mandates for control of SO_2, NOx, and possibly Hg, combined with proposed new coal-fired generation, will significantly stretch control technology supply chains. The result will be severe price escalation and threats to timely project completion.

[1] According to some observers, there are three erectors of stacks in the world with qualified experience to provide a satisfactory design; all are reportedly booked through 2011.

SECTION 2

INTRODUCTION

The cost for capital equipment for the power industry is rapidly escalating. In the U.S., several environmental mandates for control of flue gas emissions that stem from the 1990 Clean Air Act Amendments (CAAA) are converging within the time span of only a few years. In addition, the need for new, predominantly coal-fired power stations not only in the U.S. but around the world has increased the demand for material and labor. Internationally, the general robust world-wide demand for chemical processing facilities, transportation, and urban infrastructure further absorb material and specialized construction labor. As a consequence, the capital cost for almost all power industry equipment has increased, and delivery times extended.

On the supply side, the dearth of construction in the mid 1990s for equipment and services of this type prompted suppliers and specialized construction labor to migrate to other industries. Consequently, the supply field is limited, particularly for specialty items required in general chemical and industrial applications, such as rubber-lined slurry pumps, pulverization and reagent grinding equipment, and flue gas emission stacks.

The combination of higher equipment costs and schedule delays challenges utilities implementing plans to meet emission caps or other emission reduction requirements for SO_2, NOx, and Hg. Some operators may not be able to meet their compliance mandates on schedule without purchase of emissions allowances, or will incur escalated compliance costs.

This paper summarizes the cost trends observed in recent years for flue gas controls for both SO_2 and NOx, and the prospects for Hg controls. Section 3 provides relevant background information, addressing the projected capacity to be retrofit of environmental controls, and projected capacity of new coal-fired plants. Section 4 summarizes the key issues important to escalation of both material and labor. Section 5 highlights the factors affecting capital cost of both flue gas desulfurization (FGD) and selective catalytic reduction (SCR) NOx control process equipment. Section 6 overviews recent reports of incurred and projected FGD cost, and Section 7 addresses the same for SCR NOx control. The implications of this building environment on Hg control are presented in Section 8, and a summary presented in Section 9.

SECTION 3

BACKGROUND

3.1 INTRODUCTION

Numerous regulatory programs prompt the installation of environmental control equipment for the U.S. power industry. In addition to the retrofit of existing units, the large number of new units proposed impacts the availability of equipment, resources and construction labor. This section reviews these driving forces.

3.2 RETROFIT OF CONTROL TECHNOLOGY

Retrofit of control technology to existing plants is mandated by several actions subsequent to the 1990 Clean Air Act Amendment: the Clean Air Interstate Rule (CAIR), and regional haze initiatives such as the Clean Air Visibility Rule (CAVR). Further, settlements with EPA and the Department of Justice (DOJ) over alleged new source review (NSR) violations may affect plans for SO_2 and NOx reduction. Each of these is addressed in the following.

Clean Air Interstate Rule (CAIR). This two-phase program mandates reducing NOx and SO_2 in an initial Phase 1 (2009 for NOx and 2010 for SO_2), and a subsequent Phase 2 (2015 for both SO_2 and NOx). The CAIR program is the key driving force behind FGD and SCR deployment.

Best Available Retrofit Technology (BART). BART requirements are part of the Clean Air Visibility Rule (CAVR). These federal regulations require all states to revise their State Implementation Plans (SIPs) to address visibility impairment in Mandatory Class I Federal Areas, which are specific national parks and wilderness areas across the country. One of the provisions of the federal regulations is the application of BART to certain existing major stationary sources that were put into service between 1962 and 1977. The rule requires these facilities to conduct BART analysis (a very extensive undertaking) on each affected unit to determine the control technology and the level of emission controls representing BART. Consequently, even in the case of facilities that are not required to install additional emission controls to meet BART requirements, states may require retrofit of emissions controls to implement the CAVR directive that states develop plans to achieve “reasonable progress” toward eliminating manmade impairment of visibility in Mandatory Class I Federal Areas.

For example, the states of Illinois, Indiana, Michigan, and Wisconsin, through the Lake Michigan Air Directors Consortium (LADCO), are considering additional control measures for SO_2 and NOx beyond CAIR. Regulatory agencies in other regions in the country such as the southeast (VISTAS) and far west (WRAP) are considering similar mandates. The extent and timing of these mandates is uncertain, but most proposed initiatives will require control equipment by the 2014 to 2018 time period.

Settlements Regarding Alleged NSR Violations. Allegations by the U.S. EPA that provisions of the CAAA regarding New Source Review (NSR) were violated prompted several owners to alter FGD and SCR schedules from that required to meet CAIR.

Retrofit of FGD and SCR to a significant population of coal-fired stations is required to meet these existing and proposed mandates. Figures 3-1 to 3-6 depict the inventory of wet and dry FGD, and SCR process equipment that has been announced to meet the CAIR and other mandates. Figure 3-1 shows the annual addition as generating capacity (MW) of both wet and dry FGD, and Figure 3-2 the cumulative totals, both through 2010. Figures 3-3 and Figure 3-4 show the incremental and cumulative generating capacity retrofit with SCR over the same time period.

Of significance to CAMR compliance is the "co-benefit" of Hg control where oxidized Hg is removed as a consequence of SCR and wet FGD. Figures 3-5 and 3-6 show the annual and cumulative generating capacity predicted to be equipped with both SCR and wet FGD, designated by the first year of operation with both control systems. Figures 3-5 and 3-6 provide an estimate of generating units that can conceivably exploit NOx and SO_2 controls for mercury removal.

3.3 NEW GENERATING STATIONS

The number of new coal-fired units planned for operation between 2009 and 2020 is unprecedented, and will further stretch resources for construction of new FGD and SCR process equipment. Approximately 80 GW of new coal-fired generating capacity has been proposed (Figueroa, 2006). Although it is not clear how many of these units will actually be built, even one-half of the proposed capacity will exert considerable strain on suppliers, resources and construction labor.

There is already evidence that the significant number of retrofit emission control technologies and new plants is straining resources. This evidence can be seen by the escalation in prices of basic materials, and delays in schedule to procure these basic materials. The price escalation and schedule delays are addressed in the next section.

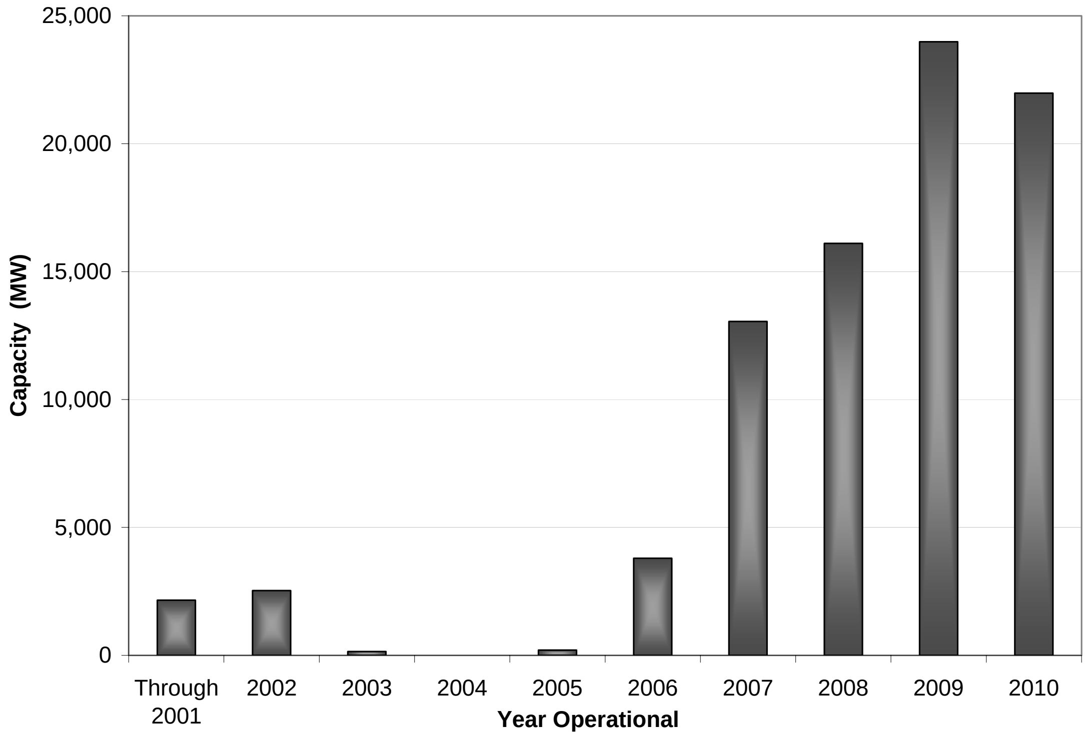


Figure 3-1. Historical and Projected Wet, Dry FGD Capacity: Installed MW per Year

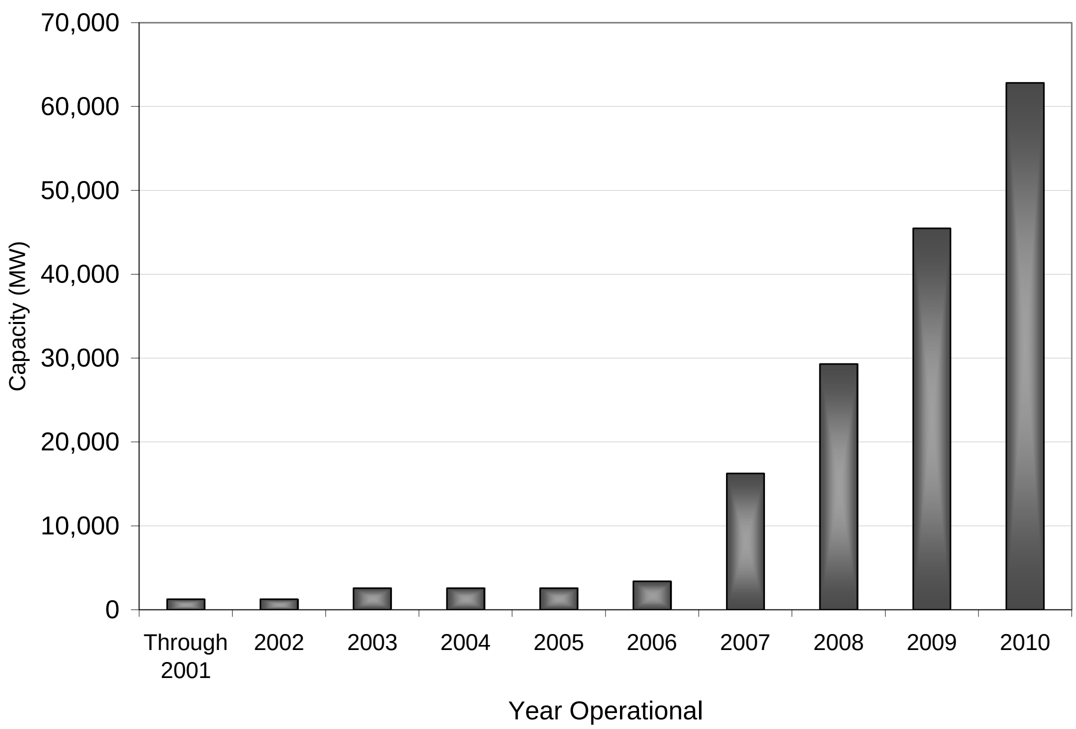


Figure 3-2. Historical and Projected Wet, Dry FGD Capacity: Cumulative MW per Year

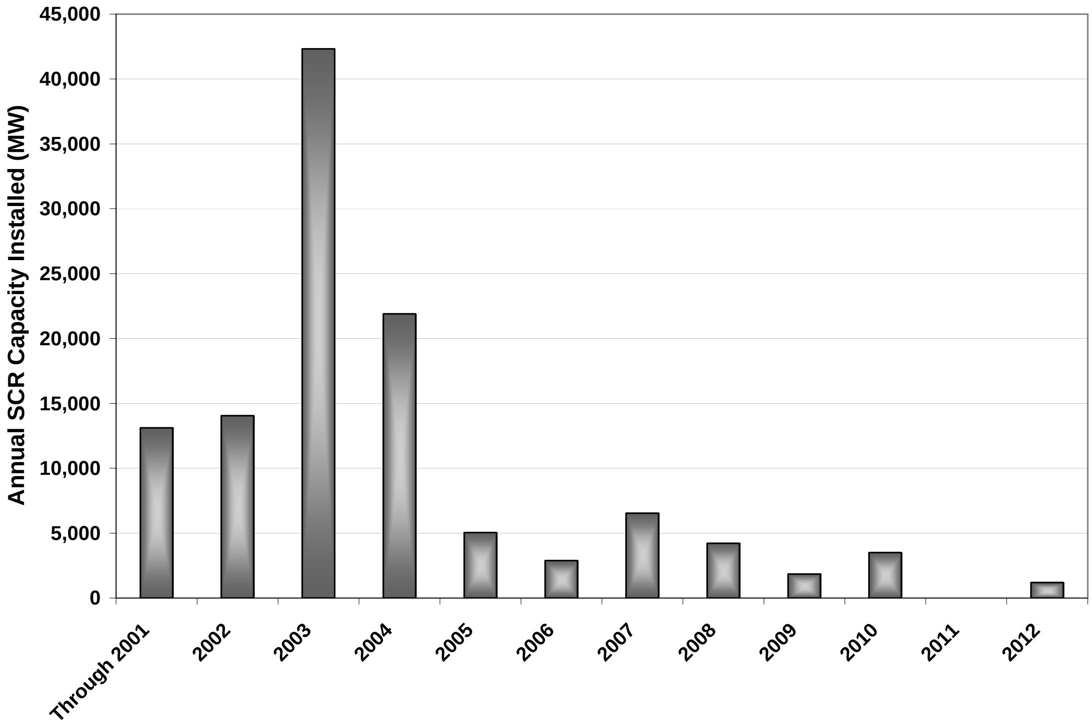


Figure 3-3. Historical and Projected SCR Capacity: Annual Installed Capacity (MW)

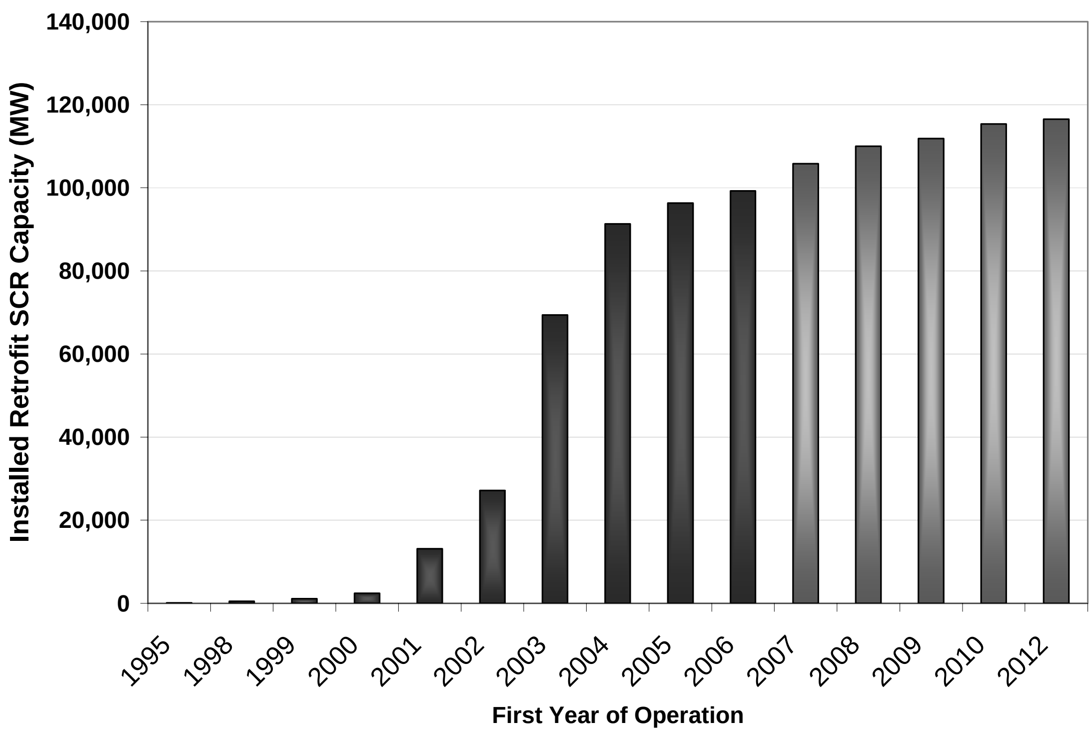


Figure 3-4. Historical and Projected SCR Capacity: Cumulative Installed SCR Capacity (MW)

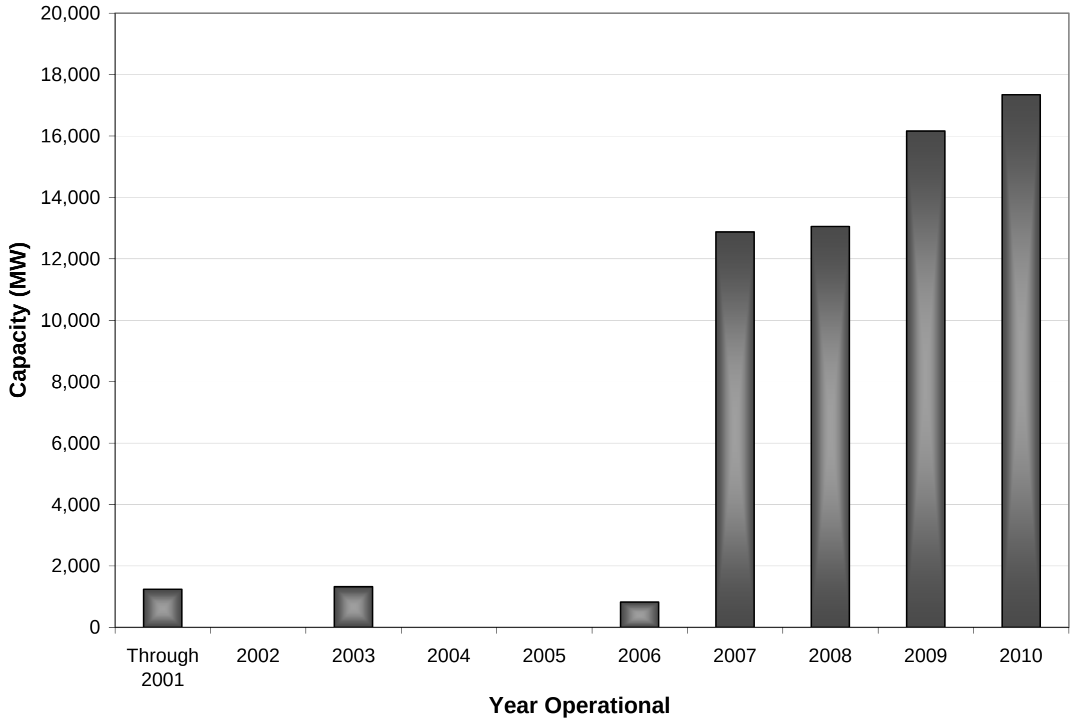


Figure 3-5. Historical and Projected Capacity: FGD and SCR, Annual Installed Capacity (MW)

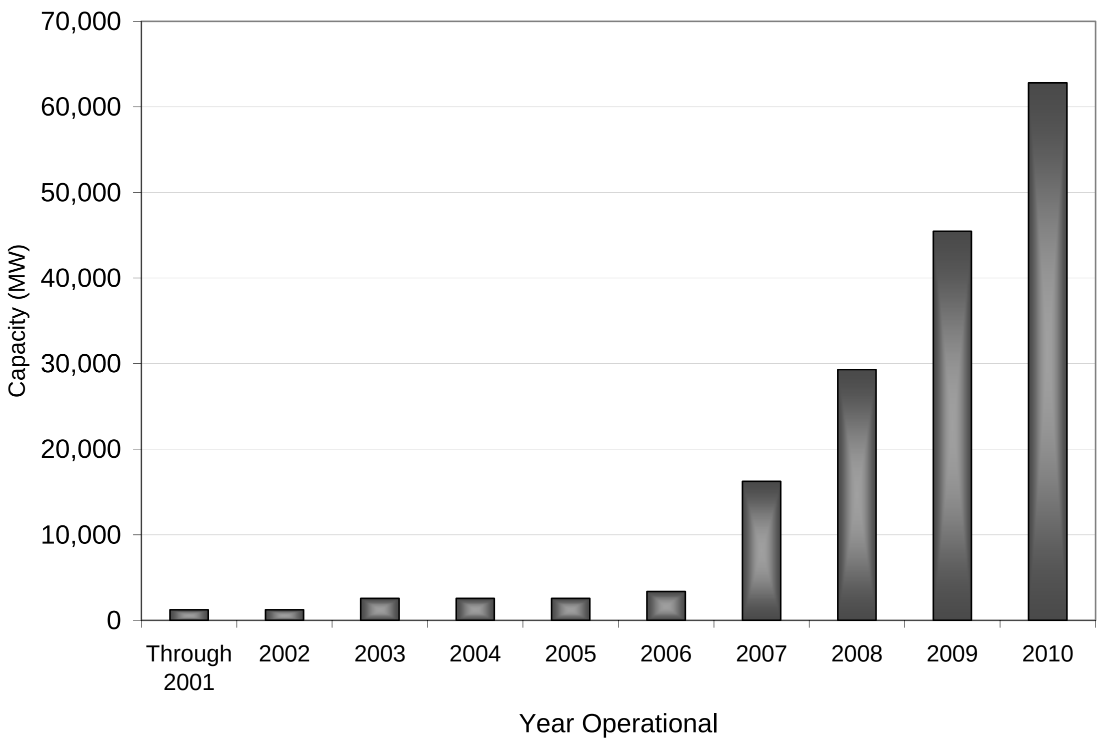


Figure 3-6. Historical and Projected Capacity: FGD and SCR Cumulative Installed Capacity (MW)

SECTION 4

MATERIAL AND LABOR ESCALATION

This section addresses the cost escalation of material and labor, and the impact of installed equipment cost and construction schedule.

4.1 BASIC MATERIALS

Among the basic materials required for both installation of retrofit of control technology and new generating equipment are structural steel, ready-mix concrete, copper wire and cable, and fabricated steel plate. These materials are broadly available in the U.S. and throughout the world, but are experiencing strong demand due to world-wide needs for process industries and infrastructure.

Figures 4-1 to 4-4 present price escalation data for these materials over the last five years, from December 2002 and into early 2007, as reported to the U.S. Bureau of Economic Analysis[2]. For three categories of these materials, prices have increased by 40% over the December 2002 value. The exception is for Copper Cable and Wiring for which price has increased by a factor of three.

Prices for special alloys used in wet FGD reaction vessels, and high pressure, high temperature boiler components have also escalated. Both nickel and molybdenum, key to production of corrosion-resistant and high strength materials, have witnessed increased demand and price. Figures 4-5 and 4-6 present price trends for molybdenum and nickel, showing prices have escalated by factors of 3 to 5, respectively. Although the mass content of these components in finished steel product is small, escalations of these magnitudes will have a material affect final product cost.

The impact of this escalation on the cost of components for wet and dry FGD and SCR is shown in Table 4-1, as witnessed from 2004 to early 2007. Although all of these factors are important, perhaps most significant is stack cost – driven by both material demand and the limited supply of qualified erectors. The limited number of stack erectors world-wide, coupled with the demand for new stacks for both retrofit of wet FGD and new generating units, has significantly elevated costs.

The limited supply of materials not only elevates cost but can delay construction schedule. Table 4-2 reports the increase in component lead time, as measured in terms of weeks from order to delivery time. The lead time for several of these components has more than doubled, based on comparing data for December 2006 and September 2003.

These basic materials, once procured, may incur a further delay to be installed. A world-wide shortage of cranes has added to the schedule delay and cost escalation (Brat, 2007).

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[2] See U.S. Bureau of Economic Analysis, “Price Indices for Gross Domestic Product by Major Type of Product”, revised April 27, 2007, downloaded May 25, 2007, http://www.bea.gov/national/nipaweb/SelectTable.asp?Selected=Y

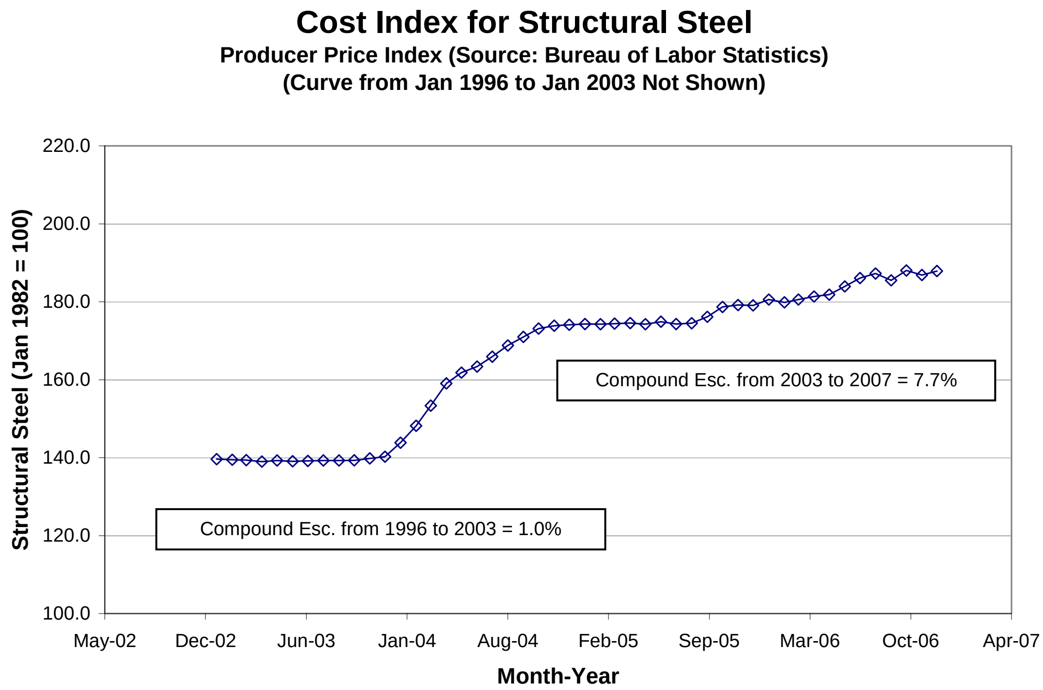

Figure 4-1. Structural Steel Cost Escalation

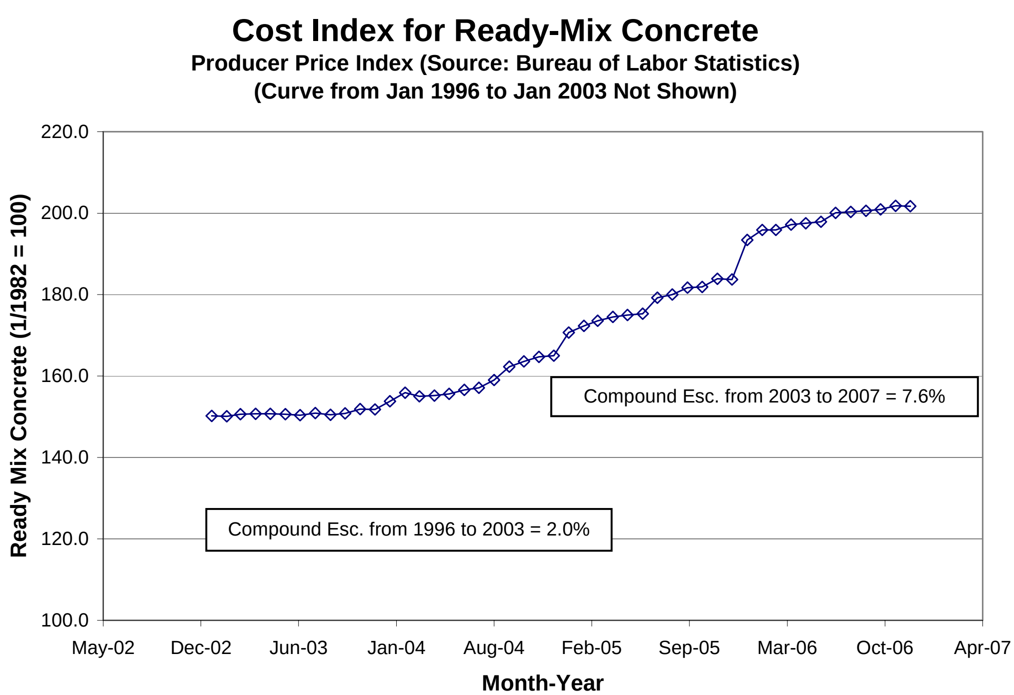

Figure 4-2. Ready-Mix Concrete Cost Escalation

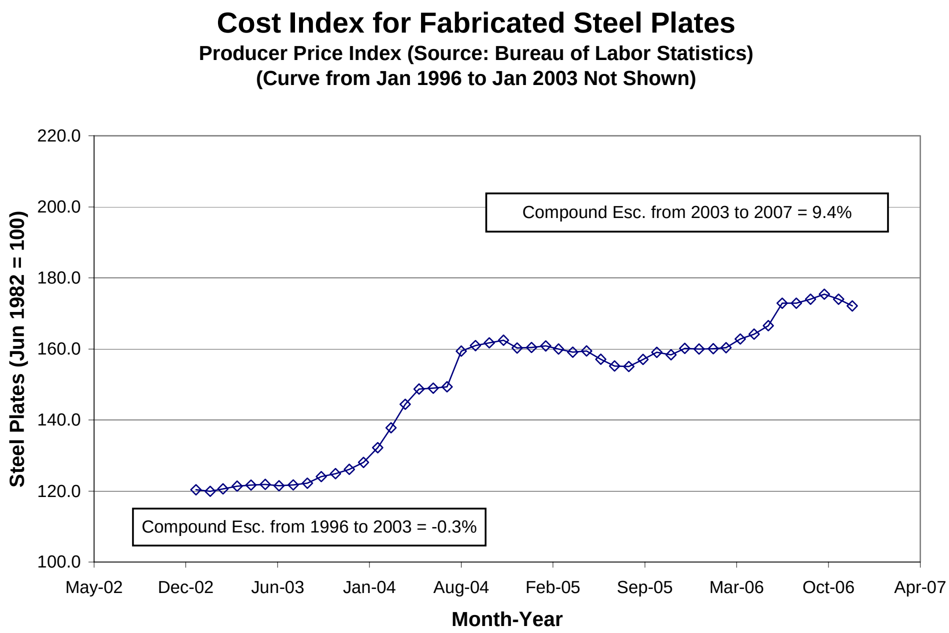

Figure 4-3. Fabricated Steel Plate Cost Escalation

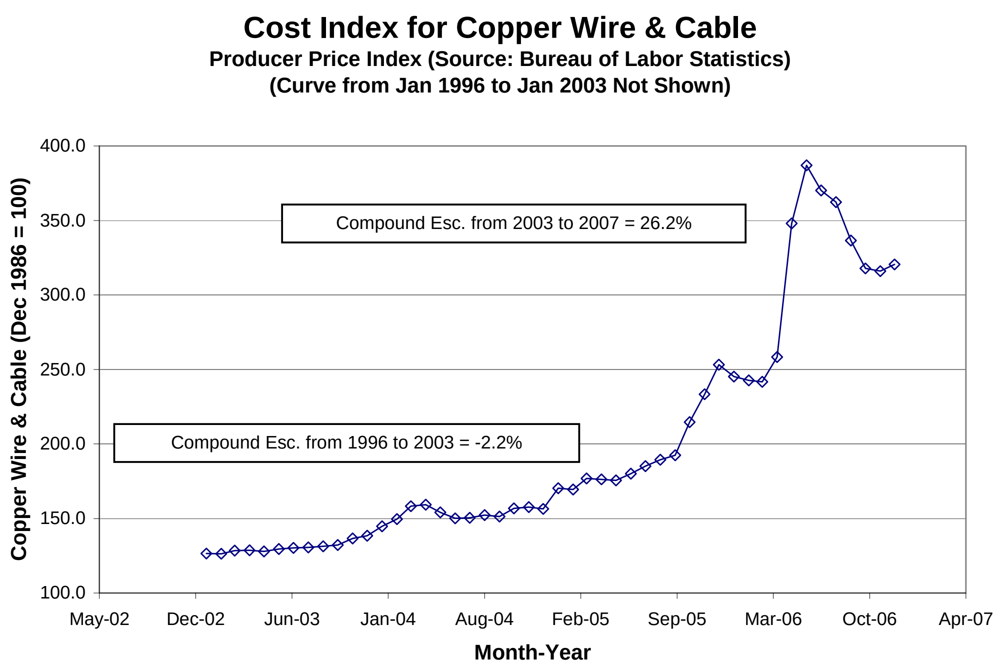

Figure 4-4. Copper Wire and Cable Cost Escalation

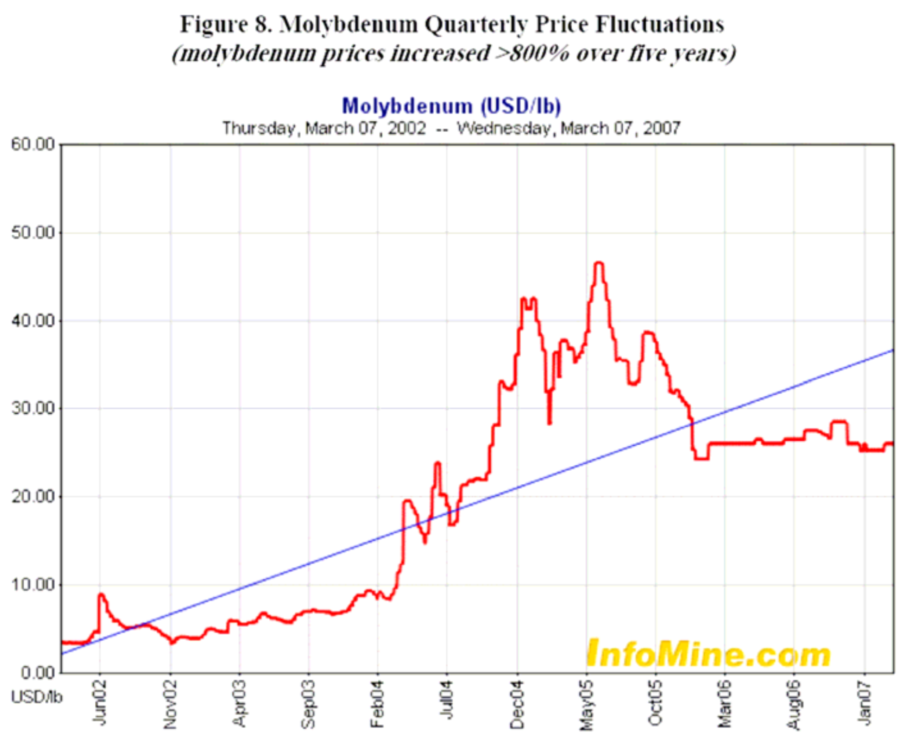

Figure 4-5. Molybdenum Price Escalation

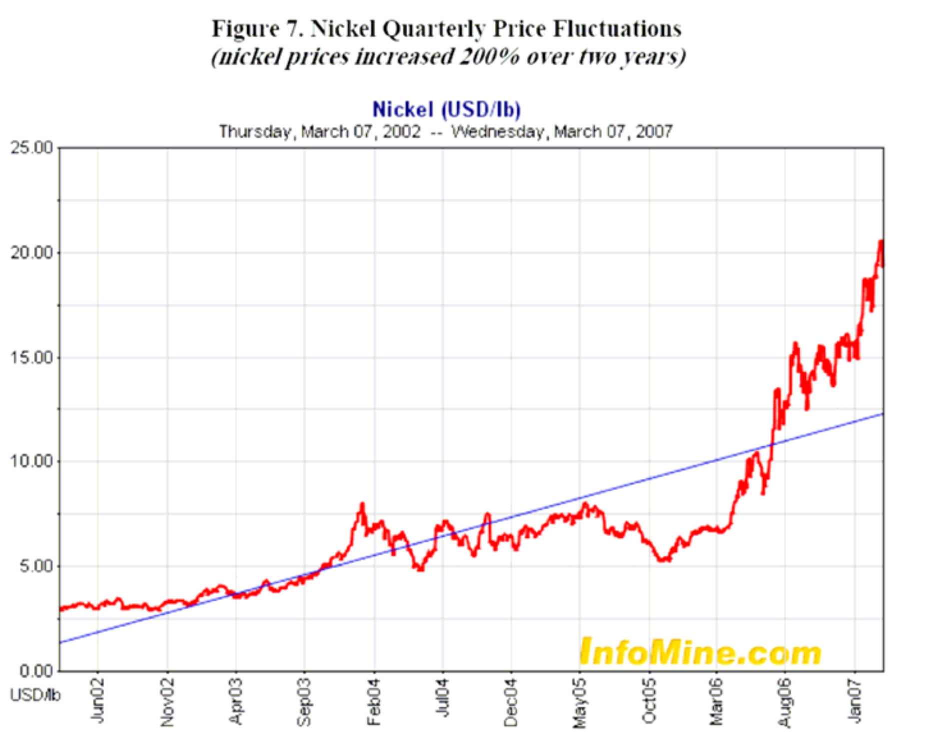

Figure 4-6. Nickel Price Escalation

Table 4-1. Escalation of Key Wet FGD Components: 2004 – 2007

FGD Component	Price Increase, %
Transformers	50+
Stack	50
Steel Pipe	40+
Field Fabricated Steel Tanks	23
Pumps	18
Pulverizers	18
Conveyors	17
Fans	16

Table 4-2. Increase in Component Lead Time, Weeks (December 2006 vs. September 2003)

	Total Lead Time, Weeks			
Equipment	*Sept '03*	*Oct '05*	*Aug '06*	*Dec '06*
Ball Mills	32	65	68	70
Rubber-lined Recycle Pumps	26	52	92	112
Booster Fans	-	54	54	60
Oxidation Air Compressors	32	44	44	52
Internal Recycle Spray Headers	28	40	40	48

Source: Katzberger, 2007

4.2 LABOR

The present cost trends and potential for shortages for qualified field labor are discussed in this section.

4.2.1 Labor Cost Escalation

Labor cost escalation experienced by the industry is shown in Table 4-3. This data, developed by an architect/engineering firm involved in the construction of several new Midwestern plants, shows the annual labor escalation to be between 5.2 and 7.4% per year, averaging 6.2%.

Labor and equipment required for installing a control technology constitutes about half the total cost – with the remaining costs being due to process equipment acquisition and design. Not all installation cost is devoted to labor – cranes and other heavy equipment are required – but the labor component is significant. Inevitably, escalating labor cost will translate into higher installed emission control equipment cost.

Table 4-3. Recent Cost Escalation: Labor Rates ($/hr) for Midwestern Coal Plant Construction

CRAFT	2005	2006	2007	Annual Escalation Rate, %
Operators	28.06	29.56	31.06	5.3
Laborers	19.50	20.70	21.90	6.1
Millwright	30.00	31.85	33.70	6.2
Ironworker	25.10	26.95	28.80	7.4
Carpenter	25.65	27.50	29.35	7.2
Pipefitter	32.73	34.83	36.93	6.4
Electricians	30.73	32.58	34.43	6.0
Boilermaker	27.80	28.60	30.10	5.2
			Total	6.2

Source: Black & Veatch, 2006

4.2.2 Labor Pool Availability

The specialized labor pool required for SCR and FGD retrofit is subject to high demand and may limit equipment installation. Table 4-3 defined the skilled labor categories required for power plant construction. As noted in Table 4-3, labor rates for all categories are subject to cost pressure. Perhaps the most critical craft is "boilermakers" – the highly skilled metalworkers needed to fabricate the high pressure, high temperature steam tubes and supply casings. This labor pool is restricted due to a lengthy apprenticeship that is necessary to assure quality fabrication.

The limited boilermaker labor pool could restrict the installation of SCR and FGD process equipment. UARG comments submitted in 2003 addressing CAIR described how the installation of SCR and FGD could be limited by boilermaker availability (UARG, 2003); an updated version of these comments considering the revised SCR and FGD installation schedules and new plant construction is presented in the following section.

<u>Supply</u>. The International Brotherhood of Boilermakers (IBB) reported boilermaker membership as approximately 24,000 members in 2003, with a targeted 5.3% growth rate. The IBB did attain this growth rate, as membership in early 2007 is reported to be 32,000. Assuming a continued 5% increase in membership, the boilermaker pool will expand to approximately 36,000 members by 2010, 40,000 members by 2012, and about 46,000 members by 2015. Additional resources of 6,600 members in Canada are reported in early 2007.

<u>Labor Requirements for SCR, FGD</u>. The labor required by approximately 2010 to install SCR and FGD equipment can be estimated, using knowledge of the (a) number of manhours of labor required to construct FGD and SCR, (b) generating capacity of FGD and SCR retrofitted, and (c) the sequence of labor charges over the project duration.

Wet FGD installation for a 500 MW unit requires from 600,000 to 900,000 manhours of labor, depending on the design and site-specific conditions. The average value of 750,000 manhours equates to 1,500 manhours per MW of generating capacity. For SCR, an average of 500,000 hours is required for a 500 MW unit, which equates to 1,000 man-hours per MW of capacity. These assumptions are based on discussions with FGD and SCR process suppliers.

Installing FGD and SCR individually at a given site is assumed to require 36 and 28 months, respectively. The demand for boilermaker manhours required over the project duration is presented in Table 4-4, based on discussions with suppliers. Using the preceding information, and EPA's estimate that a typical boilermaker will work 1685 hours per year (EPA, 2003), the total number of boilermakers can be determined.

Table 4-4. Distribution of Boilermaker Labor Requirements: Hypothetical Retrofits at a 500-MW Unit

Technology	Q1	Q2	Q3	Q4	Q5	Q6	Q7	Q8	Q9
FGD	0	0	0	0	10	27	34	23	6
SCR	0	0	0	20	25	40	15	n/a	n/a

<u>Labor Required for New Plant Construction</u>. Black & Veatch has estimated the labor demand to construct the 80 GW of new plant capacity (Black & Veatch, 2006). Specifically, total craft labor is estimated to require more than 12,000 full-time equivalent positions in 2008 and 2009, decreasing to 10,000 in 2010. The number of boilermakers is conservatively estimated to constitute half of the craft labor. This projection allows the total number of boilermaker positions to be estimated from 2007 through 2013. It should be noted these are for plants announced as of 2006; this number could decrease (due to cancellations) or increase.

Figure 4-7 shows the full time boilermaker positions required for retrofit of SCR and FGD, and new plant construction, from 2008 through 2012. The projected supply of boilermakers in 2010 is approximately 31,000; thus the estimated demand of 20,000 represents a large fraction of the workforce. It should also be noted that regularly scheduled maintenance of power plants also relies upon this pool of boilermaker labor. It is unrealistic to assume that the cumulative demand on labor expended to meet the needs of the power industry will be provided without significant cost escalation and delays.

4.3 FGD COST ESCALATION

The escalation in basic materials and labor costs has elevated the cost of FGD and all categories of control technology. One index of this cost escalation, the Vatavuk cost index, reflects significant appreciation in the last 5 years. Figure 4-8 presents the trend in this cost index, showing a 50% increase since 1997.

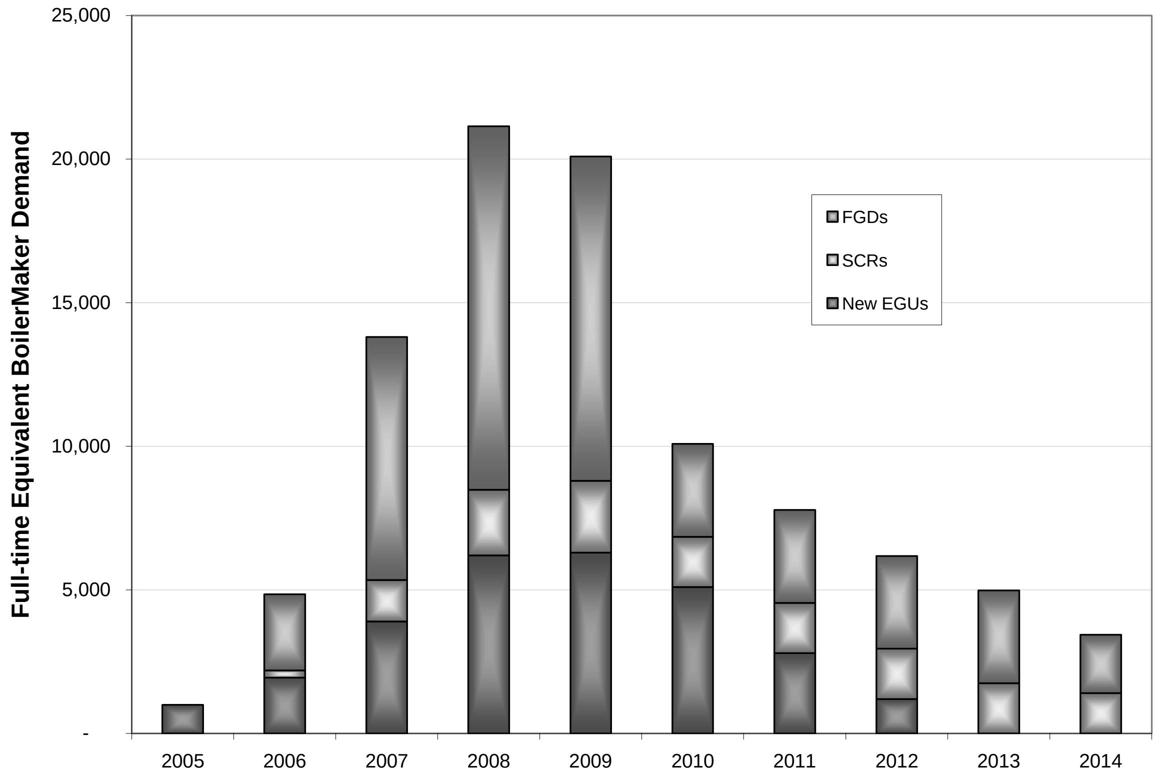

Figure 4-7. Full Time Boilermaker Demand: SCR, FGD, and New Coal-fired Units

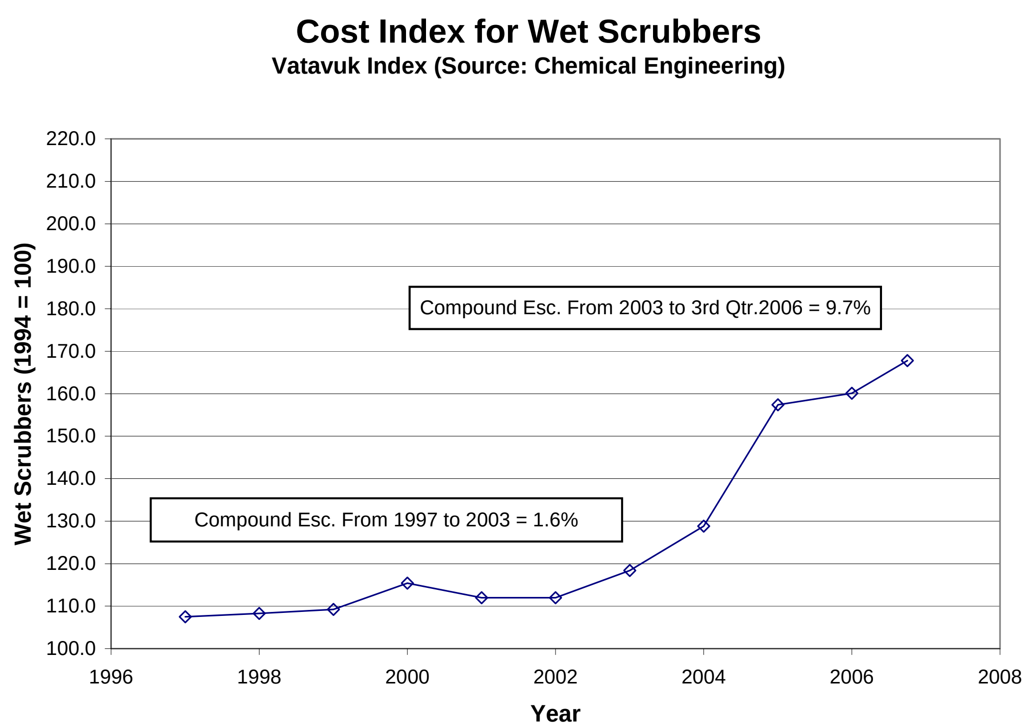

Figure 4-8. Vatavuk Index for Wet FGD Scrubbers

SECTION 5

FACTORS AFFECTING CAPITAL COST ESTIMATES

A review of factors affecting capital cost estimates is presented in this section. These involve the costing methodology, and site-specific and engineering decisions.

5.1 CAPITAL COST ESTIMATING METHODOLOGY

Evaluating the capital cost of environmental controls requires a consistent accounting of costs. All direct and indirect costs are to be considered. EPRI's Technical Assessment Guide (TAG, 1993) defines a consistent method, and has served as a model by which DOE and other organizations assess costs.

Figure 5-1 schematically depicts the key components of a capital cost estimate. The first factors establish the capital required to fabricate, deliver, and install the equipment at the site. The capital equipment directly purchased from the supplier, and installed by a construction contractor comprises the Total Process Capital. Several indirect charges consequential to these direct charges are incurred: (a) engineering design, (b) general facilities, (c) owners costs, and (d) contingencies (usually both a process and a project). Indirect fees should be consistent when comparing costs from various suppliers. Table 5-1 presents typical ranges of values historically used by EPRI, DOE, and EPA. Together with the Total Process Capital, these indirect charges comprise the Total Plant Cost.

A second series of indirect charges are incurred based on project execution: fees for the prime contractor, and financing for the construction period. Adding these costs to the Total Plant Cost determines the Total Plant Investment.

Finally, the equipment and site must be equipped with spare parts, and a supply of reagents, chemicals, or fuels, prior to operation. These pre-production charges and inventory capital complete the Total Capital Requirement.

Ideally, evaluating capital costs would utilize similar charges as defined in Figure 5-1 and Table 5-1. Some but not all data presented in Section 6 have been developed on a consistent basis. However, most reported costs are derived from the same suppliers and A/E's that use similar assumptions. These costs are inevitably scrutinized by the public utilities commissions and thus eventually tested for reasonableness. Accordingly, comparing lump-sum costs has limits but can identify trends.

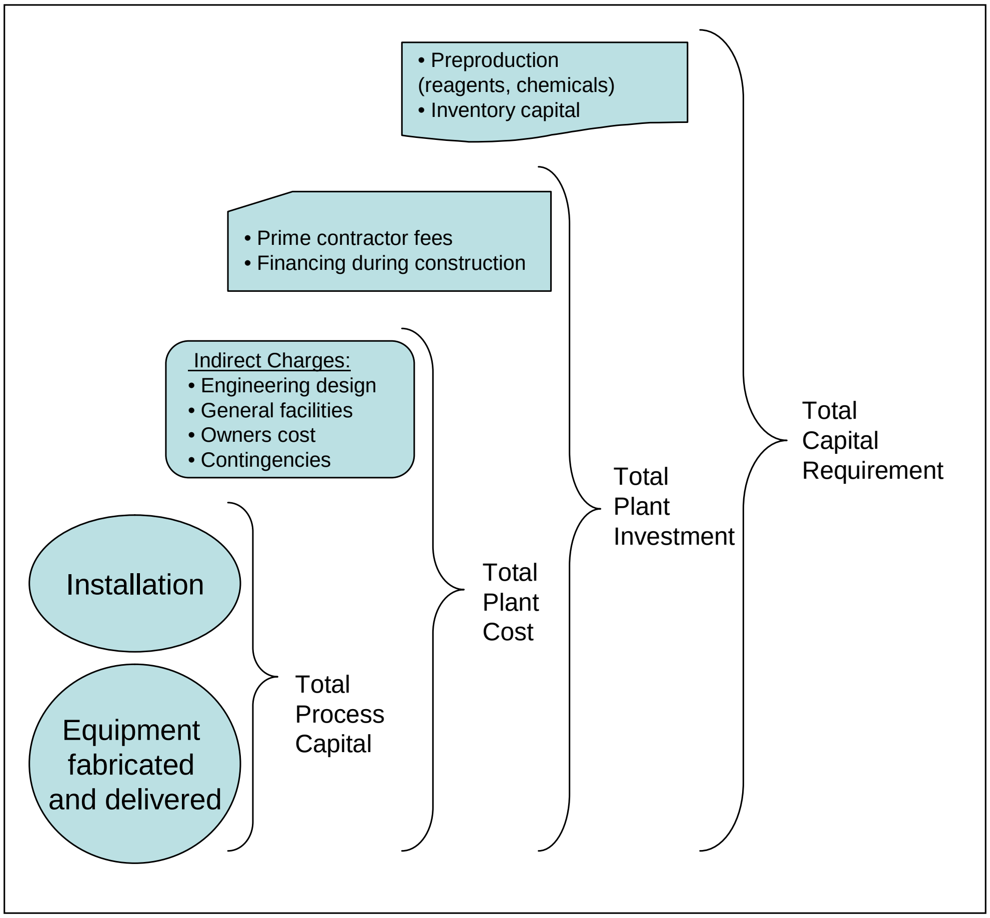

Figure 5-1. Graphic Depiction of Cost Elements

Table 5-1. Examples of Indirect Charges, Assumptions

Cost Element	Purpose	Range, %
Engineering	Establish design	7-15
General Facilities	Roads, buildings, shops, laboratories	2-5, based on process capital
Owner's Cost	Staff, management	5-10
Process Contingency	Uncertainty in process operation	5-10, for a mature process
Project Contingency	Uncertainty in site installation	5-10, if detailed engineering initially completed
Prime Contractor Fees	Business cost	2-8
AFDC	Financing during construction	5-10
Preproduction	Supply of parts, consumables	2, based on total process investment, plus 30 days fixed, variable O&M
Inventory Capital	Supply of consumables	Based on 30 day reagent, chemicals storage

5.2 SITE AND DESIGN FACTORS

Site characteristics and the operating philosophy, particularly the owner's tolerance for equipment outages, affect capital cost. These and other factors are responsible for significant variation in estimates of capital cost among projects.

The key site specific factors that define capital cost are:

Fuel Composition. The fuel defines the volume of combustion products, content of particulates, SO_2, and NOx production rates, and composition of fly ash. These characteristics drive process equipment cost. Most significant is the volume of flue gas produced by fuel combustion. For example, PRB or other sub-bituminous coals can generate 30% greater volume flue gas to be treated, compared to an eastern bituminous coal, per unit generating capacity. For FGD, the amount of sulfur to be processed and the disposition of the byproduct are factors. For SCR, the flue gas volume, and composition of ash and trace elements such as arsenic can determine reactor volume and catalyst layout.

Site Congestion and Retrofit Difficulty. Limited space for equipment location, access for construction, and access for labor will extend installation time. Generally, older units of smaller generating capacity will incur high costs due to limited access (as well as penalties due to economies-of-scale). Large generating units do not necessarily guarantee adequate space for equipment installation. For example, at Duke Power's Belews Creek station, the large site for these two 1200 MW units was constrained, necessitating locating the pre-assembly "laydown" area over 1 mile from the plant. Access for SCR retrofit requires construction near the boiler economizer exit, and is usually more constrained than for wet FGD, typically located near the stack.

Existing Site Auxiliary and Support Facilities. FGD and SCR process equipment demand auxiliary power, steam, and compressed air. The availability of these consumables at a site varies, and additional infrastructure to supply and distribute these consumables may be necessary. The most costly of these can be a power distribution or "motor control center". The escalation in price of copper-derived electrical subsystems has contributed to cost increases; historically electrical infrastructure has been 5-6% of an FGD budget but now can exceed 10% for some applications.

Draft System Upgrades. The retrofit of environmental controls will change the static pressure within the ductwork, which may require upgrades to fans, new fan motors, upgraded electrical systems, and strengthening of ductwork, ESPs, and boiler walls. The upgrade and strengthening of ductwork and boiler walls is necessary to prevent collapse or implosion.

Water Treatment Requirements. For wet FGD, the need to treat process discharge water varies depending on permitted limits. Zero-water discharge requirements can impose significant costs on the entire FGD slurry treatment and dewatering systems, and may possibly interfere with FGD chemistry.

Stack Rebuild or Replacement. Retrofit of wet FGD process equipment can require replacement or significant rebuild of the stack. Flue gas treated by wet FGD poses corrosion and deposition potential, due to relatively low saturation temperature and high content of SO_3. The least cost solution usually requires a new stack rather than retrofitting corrosion-resistant liners to an existing stack. FGD implementation can be limited by the availability of expertise and resources to erect a new stack.

Equipment Sparing Philosophy. The operating strategy of the owner, and the cost incurred for an FGD outage in terms of compliance margin and SO_2 allowances determines the equipment sparing strategy. Operators with sufficient margin in meeting the SO_2 or NOx cap, or for whom SO_2 or NOx "allowances" are available, may choose to lower capital cost by minimizing redundant equipment. Conversely, operators for whom access to SO_2 or NOx allowances is limited or costly may elect to invest in more spare equipment. Sparing philosophy can affect capital cost by 10-20%.

Materials of Construction. The use of materials that resist corrosion and erosion, in an effort to obtain high reliability, can elevate capital cost. Specifically, high alloy containing steels or rubber-lined absorber vessels or pumps have historically increased reliability. Decisions affecting materials of construction, similar to those for equipment sparing, are driven by the incurred cost for an FGD or SCR outage. For wet FGD, the use of higher alloy and lined equipment can add 10-20% to the project capital cost.

Capital versus Operating Cost. Many decisions revert to a tradeoff between capital and operating cost; capital savings derived can be at the expense of higher operating cost. For SCR, a key example is the catalyst layout – the number of initial and final layers of catalyst utilized. For example, a reactor layout of 2 initial layers and 1 spare layer (e.g., 2+1) will provide a lower capital but higher operating cost, compared to utilizing 3 initial layers and 1 spare layers (e.g. 3+1). The key difference is higher catalyst consumption over a long-term period.

Of these factors, perhaps the most important is site complexity. Plant sites where FGD and SCR are to be retrofit have become more complex: longer ductwork runs are required, and access for construction equipment is limited, restricting labor productivity and extending construction time.

SECTION 6

FLUE GAS DESULFURIZATION COSTS

This section presents capital and operating costs for wet and dry FGD process equipment.

6.1 FGD CAPITAL COST

Figure 6-1 depicts capital cost presented as a function of generating capacity, for wet FGD and dry FGD processes. The design basis for these installations is described as follows:

Wet FGD. All units employ limestone reagent, forced oxidation, deliver at least 95% SO_2 removal, and are equipped with mist eliminators. The influence of design or performance conditions different from those stated will impact cost, perhaps most significantly due to variations in inlet SO_2 and the size of byproduct handling equipment. However, these cost variations are believed to be no greater than those due to physical differences between sites.

Dry FGD. The costs for all units with a lime-based spray dryer absorber (SDA) include a secondary fabric filter particulate collector. Most SDA equipment is designed for 93-95% SO_2 removal. The fly ash is removed in the existing particulate control device (an ESP in all cases), so ash handling and disposition is the same as prior to retrofit. Similar to the case for wet FGD, any differences in dry FGD SDA design from those stated are not anticipated to effect capital cost.

Capital costs in this figure are expressed in end-of-year 2006 dollars, and represent the owner's best estimate for a ready-to-operate FGD process accounting for all direct and indirect charges. Two sources of costs are discussed: anonymous and fully disclosed. Given the competitive nature of the industry, and the of role SO_2 allowances in compliance, some owners are concerned knowledge of FGD cost will bias their allowance prices. The cost sources are discussed by category.

6.1.1 Anonymous

Sargent & Lundy (S&L) Engineers conducted a detailed study for three Midwestern systems: Wet and dry FGD for System A; Dry FGD alone for System B; and Wet and Dry FGD for System C. These three systems comprise 10 wet and 24 dry FGD units for installed generating capacity varying between approximately 200 and 800 MW. Discussions with S&L staff indicate that the assumptions in Table 5-2 are generally consistent for all generating systems. Notably, the capital cost for System A exceeds that for Systems B and C, as the former sites are more congested than the latter, complicating retrofit and construction.

Two units in the Southeast of 850 and 1100 MW generating capacity exhibit wet FGD costs of almost $300/kW and $275/kW, respectively.

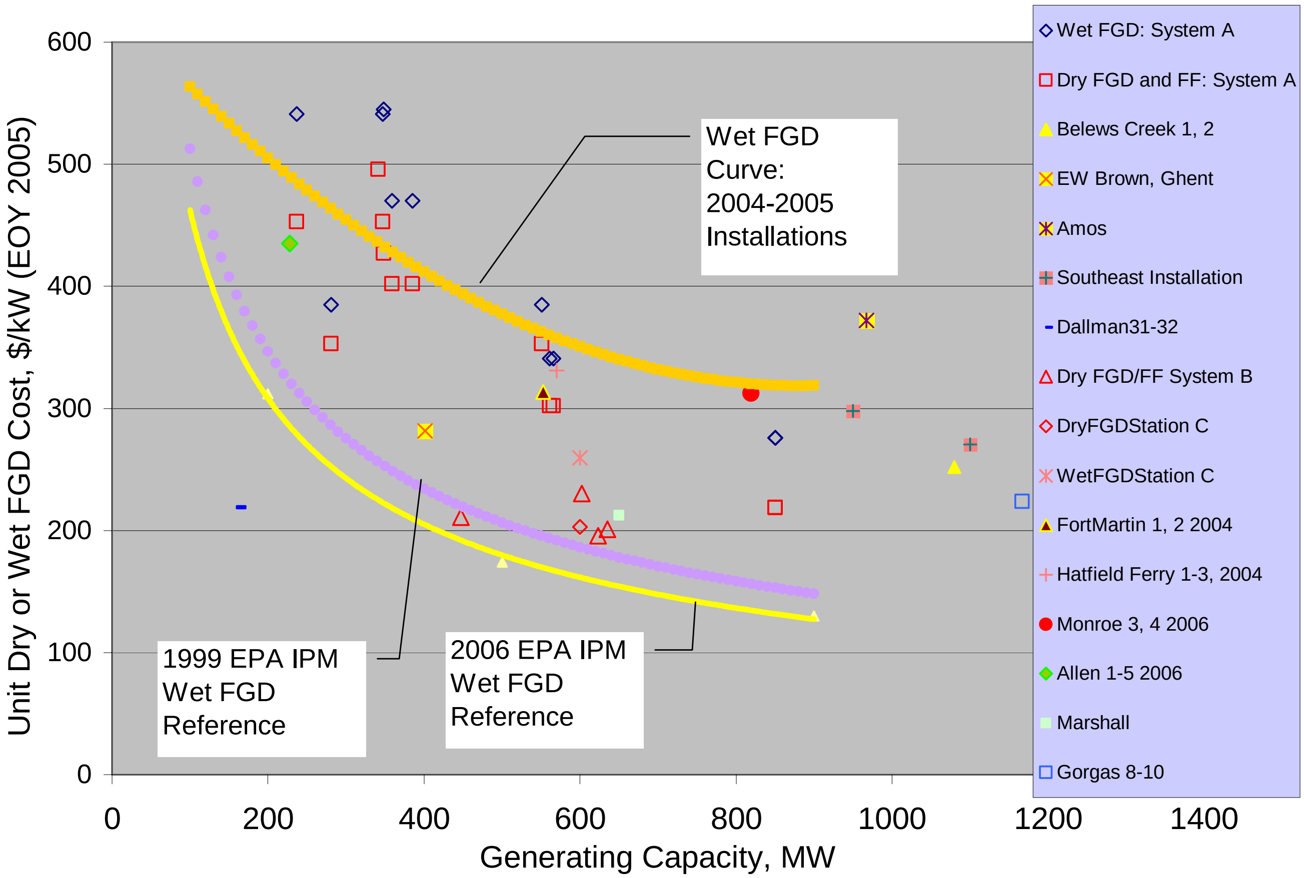

Figure 6-1. Wet, Dry FGD Process Equipment Cost: Various Sources

6.1.2 Publicly Released Studies

Publicly released cost data are described as follows:

American Electric Power (AEP): Amos. The Amos units, at nearly 1000 MW, will require $375/kW.

Allegheny Energy: Fort Martin, Hatfield Ferry. Wet FGD for these 600 MW units was estimated in 2004 to require more than $300/kW. As will be noted subsequently, actual costs incurred in 2006 for these units significantly exceeded this value.

Detroit Edison Company: Monroe 3, 4: These 800 MW units will incur capital cost greater than $300/kW, despite exploiting economies of scale in engineering and procurement.

Duke Energy has publicly released all wet FGD costs to comply with North Carolina Clean Air Legislation (Everett, 2007):

- Belews Creek 1, 2. The wet FGD $238/kW capital cost for these units is one of the lowest encountered. Duke achieved this relatively low cost by developing a system-wide design to apply to over 4,000 MW of capacity, utilizing two generic spray tower designs and common water management and solid processing equipment for the entire system (McCarthy, 2004). Economies-of-scale for engineering and procurement also contribute to the lower cost, as well as the relatively early date (2002) in which Duke engaged the FGD contractor.

- Allen Units 1-4. The relatively small generating capacity of these units (190 MW) imposes capital cost penalties due to scale, even though four units of nearly identical design are installed, utilizing the generic system spray towers (McCarthy, 2004). At more than $400/kW, these FGD installations are among the highest cost.

- Marshall Unit 1-4. Four units at Marshall (2 x 650 MW and 2 x 350 MW) employ the wet FGD system design and incur slightly greater than $200/kW. This site benefits from economies-of-scale to lower the average unit cost to this value.

East Kentucky Power: E.W. Brown, Ghent. These units incur relatively low costs of $300/kW. The remote location and relative good access likely contributes to these lower costs.

CIPS Springfield: Dallman, and South Illinois Power Co-Operative: Marion. Both of these units incur capital of less than $200/kW, for units in which contracts were signed in 2002.

WE Energies: Pleasant Prairie Units 1, 2. The design and cost for these twin 617 MW units was established in 2004, and equipment contracted for mostly in 2004 and 2005. The capital cost of $218/kW (2006 dollar basis) exploits economies-of-scale due to two identical unit designs, and common facilities such as a new stack, waste water treatment, and reagent preparation facilities.

The “Wet FGD Curve” depicted in Figure 6-1 approximates the capital cost for wet FGD processes based on a system study for the former Cinergy by S&L.

Figure 6-2 compares wet FGD cost for units where competitive bids were received in 2006. For reference, Figure 6-2 includes a curve based on Figure 6-1 that reflects wet FGD capital cost for units procured in 2004 and 2005. Also shown is the IPM cost curve as utilized by EPA in 2006 for regional modeling.

Revised wet FGD costs for two generating stations – Allegheny Energy’s Hatfield and St. Martin – are also presented in Figure 6-2. These data provide comparisons to the 2004 values. Each of these stations in 2006 received bids for wet FGD that significantly exceeded engineering estimates generated in 2004, by $75-150/kW. Although details of the higher costs are not available, the most significant contributing factors are higher installation costs and material prices. In addition, wet FGD capital cost for Reliant Energy’s Cheswick Station reported in mid-2006, and for Gulf Power’s Crist Units 4-7 (April, 2007) are presented. The wet FGD design for Crist is reported to exceed $500/kW, and will utilize two absorber vessels to treat flue gas from four units, ranging from 94 MW (two units) up to 578 MW. The disparity in generating unit size and arrangement of equipment likely contributes to this high cost, as well as 2007-based prices for material and labor.

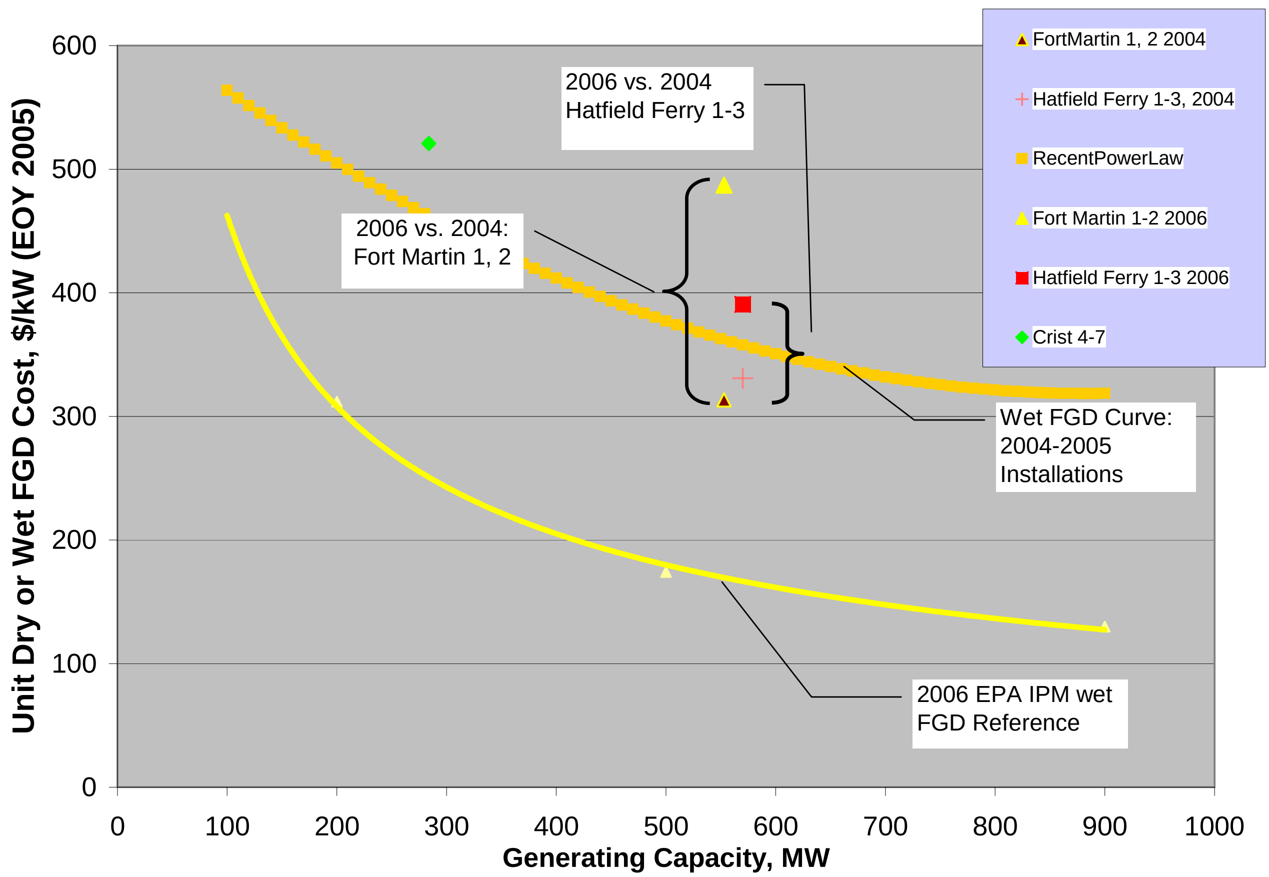

Figure 6-2. Wet, Dry FGD Process Equipment Cost: Various Sources

Of note is the disparity between cost projected by EPA and those actually incurred. The source of this disparity is unclear – the EPA methodology employs the same cost accounting principles described in Section 5, and is reported to consider balance-of-plant impacts. It is possible EPA projections are based on dated information, derived with budgetary-type analysis, as opposed to a detailed design study. It is unlikely the EPA cost algorithm reflects authentic balance-of-plant costs. For example, Duke Energy required a unique waster water management system at the Belews Creek and Marshall generating stations that employed specially-constructed wetlands. Also, Marshall required extensive duct runs to tie in the new stack. The EPA estimates do not appear to include a complete list of balance-of-plant items.

6.2 OPERATING COST

Operating cost is defined in several ways – total operating cost per unit of capacity per year, normalized to power generated, or per unit of emission species removed.

Figure 6-3 is a reproduction of a graphic presented by Sargent & Lundy at the November 2006 PowerGen conference (Sargent & Lundy, 2006). Figure 6-3 compares (for a 500 MW plant) the various contributors to total operating cost for a limestone-based wet FGD process, designed for 95-97% SO_2. Total O&M ranges from approximately \$15 to \$38/kW/yr, and is almost equally comprised of fixed and variable components. As noted in Figure 6-3, limestone reagent cost for this size of unit varies in direct proportion to the amount of sulfur in the coal. Other operating cost components directly related to sulfur content including operating and maintenance labor, and byproduct management.

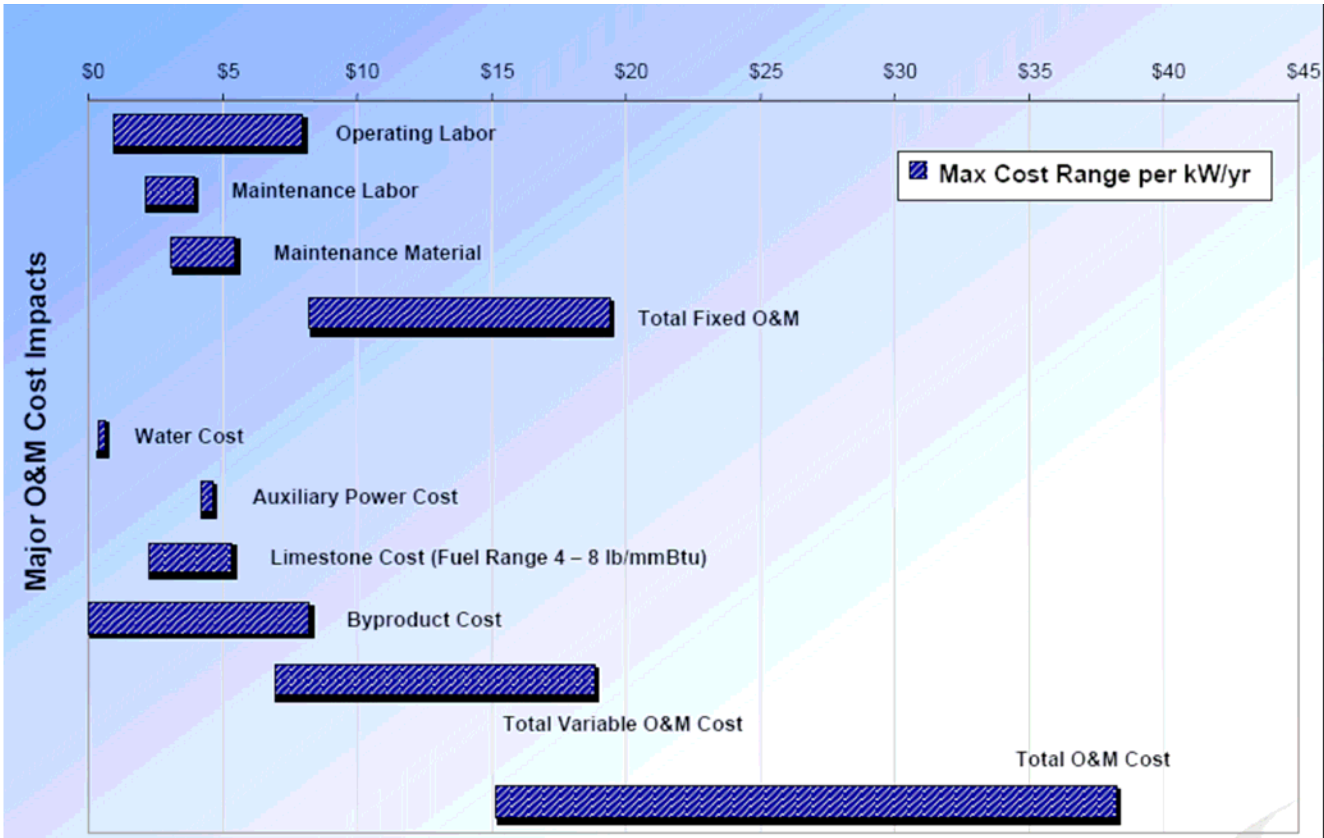

Figure 6-3. Range of Wet FGD Operating Costs for 500 MW Units (after Sargent & Lundy, 2006)

The capital cost ranges in Figures 6-1 and 6-2, when combined with operating costs, provide an indicator of FGD cost-effectiveness, or the cost per ton of SO_2 removed. Figure 6-4 presents the cost per ton of SO_2 removal for a hypothetical 500 MW unit, utilizing a limestone based forced oxidation process. Calculations are reported for coal with intermediate sulfur content (6 lb SO_2/MBtu) and for PRB (0.90 lb SO_2/MBtu). Figure 6-4 results are based on median operating costs reported in Figure 6-3 for the 6 lb SO_2 coal, and minimum values for PRB. The operating cost estimates are consistent with published sources for wet FGD, and those derived for a 500 MW unit with EPA's CUCOST software program[3]. It is possible higher operating costs may be incurred that reflect higher labor rates. Figure 6-4 results also assume a 15-year book life (e.g., cost recovery period) and thus a capital recovery factor of 0.12.

[3] Using CUCost Version 3, the sum of fixed and variable O&M for a wet limestone forced oxidation FGD process is within 5% of that derived using 500 MW generating basis, Ohio coal of 5.8 lbs SO2/MBtu, 85% capacity factor, and 10,000 Btu/kWh heat rate. Cost results are presented on a 2006 dollar basis using the CUCost imbedded routine to escalate costs with the CE Plant Index.

For the case of 6 lb SO_2/MBtu coal, an increase in capital cost from $250/kW to $450/kW increases the cost of SO_2 removal from $270 to $450/ton. For PRB coal, the same capital cost increase will elevate SO_2 removal cost from approximately $1,500 to $2,300/ton. The costs will change in proportion to the sulfur content of the fuel.

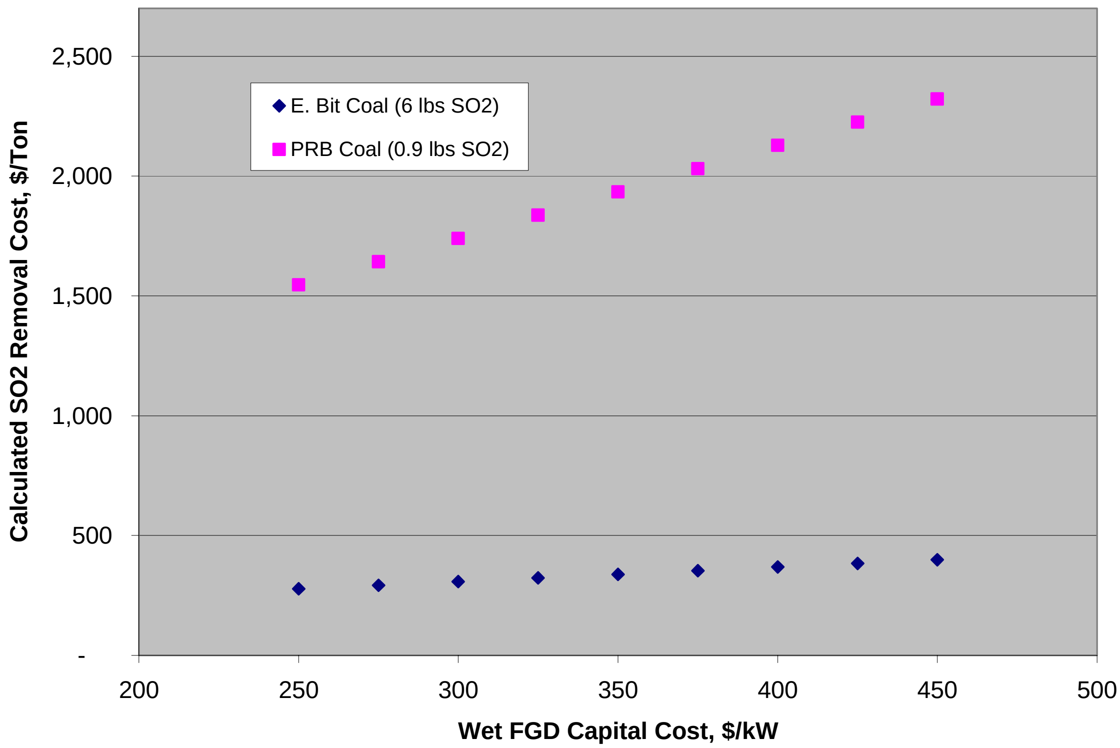

Figure 6-4. SO_2 Removal Cost per Ton ($/Ton), Year 2006 Basis

SECTION 7

SCR NOx COST

This section presents capital and operating costs for SCR NOx control.

7.1 SCR CAPITAL COST

The capital cost for SCR process equipment has been the subject of several surveys in the last four years. In most cases, the costs are reported as anonymous; the costs for only a few named units are publicly available. This section of the report will highlight results from these surveys, almost all of which were conducted prior to the cost escalation witnessed in the last 24 months. Limited data released in the last 12 months and reflecting the cost escalation will also be presented.

7.2 THREE SURVEYS

Three surveys have documented the increase in SCR capital cost: Hoskins (2003), Cichanowicz (2004), and Marano (2006). The findings from these surveys are not directly comparable to each other, as each utilizes a different unit population, and design features. Further, important factors such as the scope of equipment supply and construction labor rates have not been normalized. Table 7-1 shows the average capital cost and size of generating unit in the survey, the range of costs incurred, and includes important observations concerning these surveys. The results of each survey are summarized as follows:

Hoskins, 2003. This survey of 20 units determined an average cost of $120/kW, for units with an average generating capacity of 400 MW. More than 75% of these units reported capital costs that exceeded $100/kW. A weak relationship between capital cost and scale was noted; that is, unit cost ($/kW) did not significantly change with increasing generating capacity.

Cichanowicz, 2004. This survey of over forty units reveals a relationship between cost and generating capacity. Units of small-intermediate generating capacity (100-400 MW) required $123/kW, while the largest units (800-1200 MW) required $85/kW. This survey compared the capital cost provided by each supplier with the order of installation – that is, comparing the cost of the first unit installed by a supplier versus subsequent units. Four categories of generating capacity were examined, and in every case the least cost units were among the first installed, suggesting that either increased experience by the supplier or complexity of the unit increased the capital cost. This trend was observed prior to the recent cost escalation.

Marano, 2005. This most recent (2005) and comprehensive (60+ units) survey showed that most units reported costs of $100-200/kW, with units greater than 900 MW averaging $118 /kW, and those less than 300 MW averaging $167/kW. Marano noted that units from 600-900 MW appear to be the most difficult to retrofit. This observation is consistent with the observation of Cichanowicz, which shows capital cost actually increase with generating capacity in this range.

Table 7-1. SCR Capital Cost Survey Results

Reference	Average Capital, MW ($/kW, 2006 Basis))	Low-High Cost Observed ($/kW)	Observation
Hoskins, 2003	128 (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	84 (600-899 MW) to 128 (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 observation from the surveys reported in Table 7-1 is the low number of units with reported costs <$100/kW, and the inability of units of large generating capacity to deliver low installed cost. 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 (Power Engineering, 2002). Marano (2006) notes the early SCR adopters incurred lower capital cost, with the year of 2003 recognized as a milestone after which costs increased significantly.

7.3 COST ESCALATION

Figure 7-1 depicts the escalation of SCR capital cost over four periods of time, spanning 15 years. This escalation is described as follows:

Phase 1 and Phase 2 installations incurred atypically low capital cost. It is likely these installations did not reflect the conventional SCR retrofit in terms of access, NOx removal performance, and reactor/catalyst arrangement.

Phase 3 installations reflected increasing retrofit complexity and higher NOx control performance; process demand was robust but did not overburden the suppliers over this time period. Over 2/3 of these units incurred capital cost exceeding $100/kW.

Phase 4 comprises the recent applications that either become operational in 2006, or will start up in 2007 or 2008. These costs exceed $200/kW on a routine basis, well above the cost historically incurred.

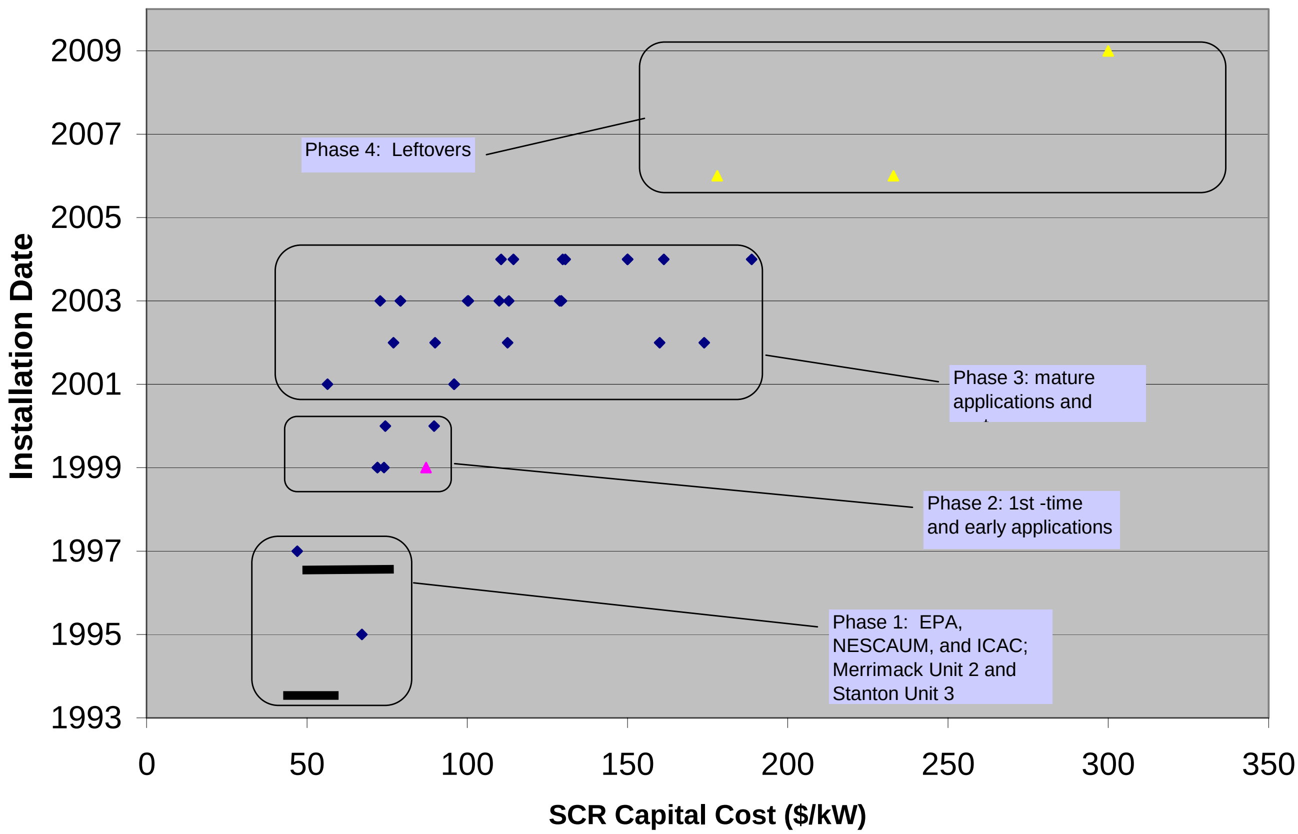

Figure 7-1. Escalation of Cost for SCR Installation with Time

7.4 OPERATING COST

Operating costs for SCR processes consist mostly of replacement catalyst and ammonia-based reagent. Each of these cost components has experienced significant price changes in the last 10 years.

7.4.1 SCR Catalyst

Historically, supply of catalyst comprised the largest operating component of SCR NOx control. The unit cost of catalyst has significantly decreased since the early 1980s, as the entry of several large multi-national firms increased supply faster than demand. Further, the ability to regenerate or rejuvenate catalyst for approximately 50% of new product price further restrains price.

Figure 7-2 presents the unit price of catalyst since the early 1980s, corrected to a 2006 dollar basis, showing a decrease in unit price by a factor of five since the earliest commercial bids. The minimum price of near $4,000 m^3 was witnessed in 2005; however, recent experience suggests prices are increasing due to a large number of units for which a first catalyst addition or supplement is required.

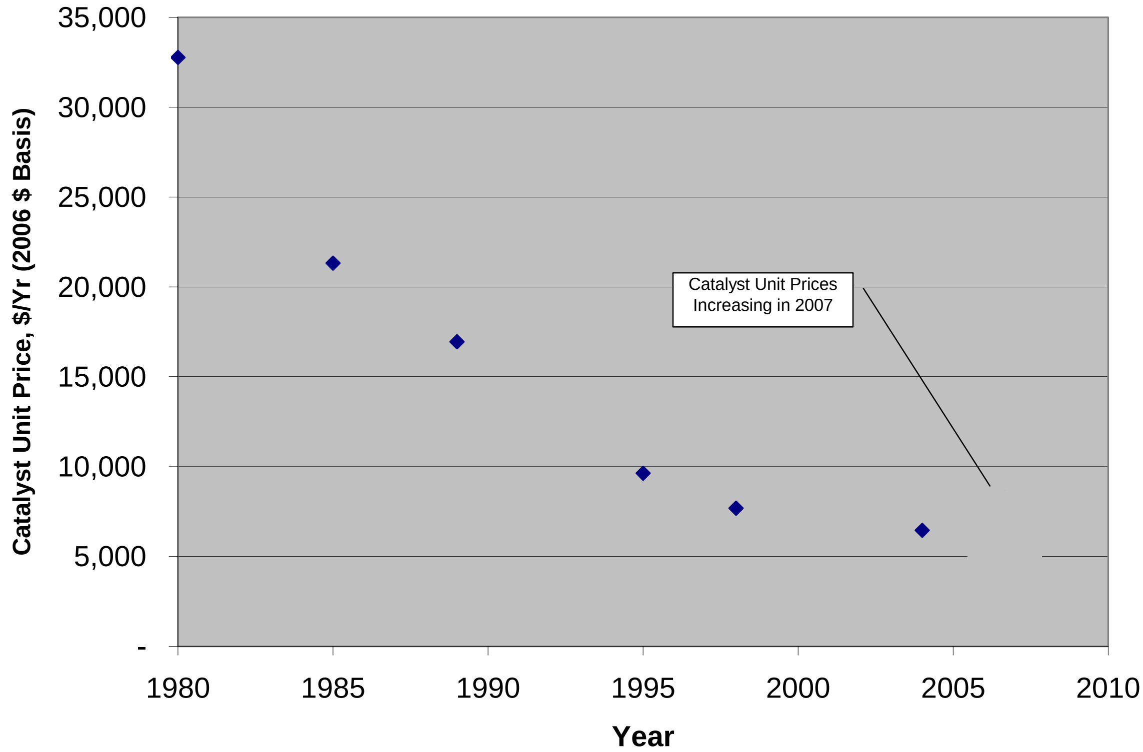

Figure 7-2. History of SCR Catalyst Prices (2006 Dollar Basis)

The consequence of this catalyst price decrease is that catalyst procurement does not dictate SCR cost as historically witnessed. In fact, catalyst management decisions at present can exploit low prices to insure the reactor features adequate catalyst activity, to confine catalyst replacement to major outages, avoiding unit shutdown for the purpose of catalyst addition or exchange.

7.4.2 Reagent

Any savings in SCR operating cost due to catalyst price decreases has been offset by escalation in delivered price of ammonia-based reagent. SCR operators can choose from four types of ammonia-based reagent: anhydrous ammonia, aqueous ammonia of 19.5% NH_3 content or 29% NH_3 content, or urea. For the purposes of this discussion, anhydrous ammonia will be discussed as an example, recognizing that the alternative reagent forms are equally viable.

The cost of anhydrous ammonia is as much as 80-90% determined by the cost of natural gas feedstock. In late 2006, typical prices for anhydrous for agriculture were approximately $400/ton. This value exceeds the 175 to $250/ton historically noted. As natural gas prices are anticipated to remain high, the price of $400/ton is anticipated to represent future cost (Clark, 2006).

7.4.3 Example Operating Cost

The operating and maintenance cost for an SCR process can be developed (for a hypothetical 500 MW unit), based on assumptions in Table 7-2 that define the conditions of operation. These are:

Fixed O&M. Spare parts and support for miscellaneous duties that must be executed regardless of unit operation are assumed to require 0.50% of process capital.

Catalyst Supply. Catalyst supply cost is determined by long-term purchases from which an annual-equivalent average can be calculated. The long-term purchases are dictated by catalyst addition to the empty spare layer, and replacement of existing layers. For an SCR reactor employing a 2+1 catalyst arrangement, 3,200 1/h initial space velocity, and a 16,000 hour initial operating guarantee, the purchase of 1 layer for every 20,000 operating hours may be required.

Reagent Cost. The purchase of anhydrous ammonia for 90% NOx removal from 0.35 lbs/MBtu, at 85% capacity factor, defines the reagent cost. A delivered price of $400/ton is assumed.

Auxiliary Power. Auxiliary power for an additional 6 in. water gauge (w.g.) flue gas pressure drop is assumed – 5 in. w.g. for the process flange-to-flange, and an additional 1 in. w.g. across the air heater.

Catalyst Cleaning. Sootblower consumption of 0.2% of the plant steam output is adopted; this steam is assigned a cost of $1/MBtu.

Operating Staff. The addition of one operator is assumed for maintenance of the above components. Also, a part time (25%) engineer to assess operation and evaluate data is assumed.

Table 7-2. Key SCR Operating Cost Components: 500 MW Reference Plant ($150/kW Capital Basis)

Operating Cost Component	Basis	Annual Cost for 500 MW ($/yr)	Annual Cost for 500 MW (mills/kWh)
Fixed O&M	0.5% of Process Capital	150,000	0.04
Labor	Operators/Part-time Engineer	125,000	0.03
Fuel Cost	Auxiliary Steam	100,000	0.02
Reagent	90% NOx removal (from 0.38 lbs/MBtu)	885,000	0.25
Auxiliary power	6 in. w.g. total @ $20/MWh	265,000	0.07
Catalyst Supply	16,000 hr guarantee for 2+1 reactor	675,000	0.15
Total		2,200,000	0.59

The capital cost observed in Figure 7-1, when combined with updated operating costs in Table 7-1, provides an indicator of SCR cost-effectiveness, or the cost per ton of NOx removed. Figure 7-2 presents the cost per ton of NOx removal for a hypothetical 500 MW unit, utilizing a 2+1 catalyst arrangement, with an initial NOx input of 0.38 lbs/MBtu, as a function of SCR capital cost. Calculations are reported for an eastern bituminous coal with approximately 0.38 lbs/MBtu furnace NOx exit, and a PRB-fired unit assumed to produce 0.20 lbs/MBtu. Results presented in Figure 7-2 for the eastern bituminous coal employ operating cost in Table 7-1, while calculations for PRB coal employ lower cost for reagent use and catalyst consistent with lower inlet NOx. Figure 7-2 results also assume a 15-year book life (e.g., cost recovery period) and thus a capital recovery factor of 0.12.

For the eastern bituminous coal, an increase in capital cost from $100/kW to $300/kW elevates the cost of NOx removal from $2,200 to almost $6,000/ton. For the PRB coal, with lower inlet NOx rate and lower operating costs, the same capital cost increase elevates NOx removal cost from approximately $1,200 to $3,200/ton. The costs will change in proportion to the boiler NOx generated.

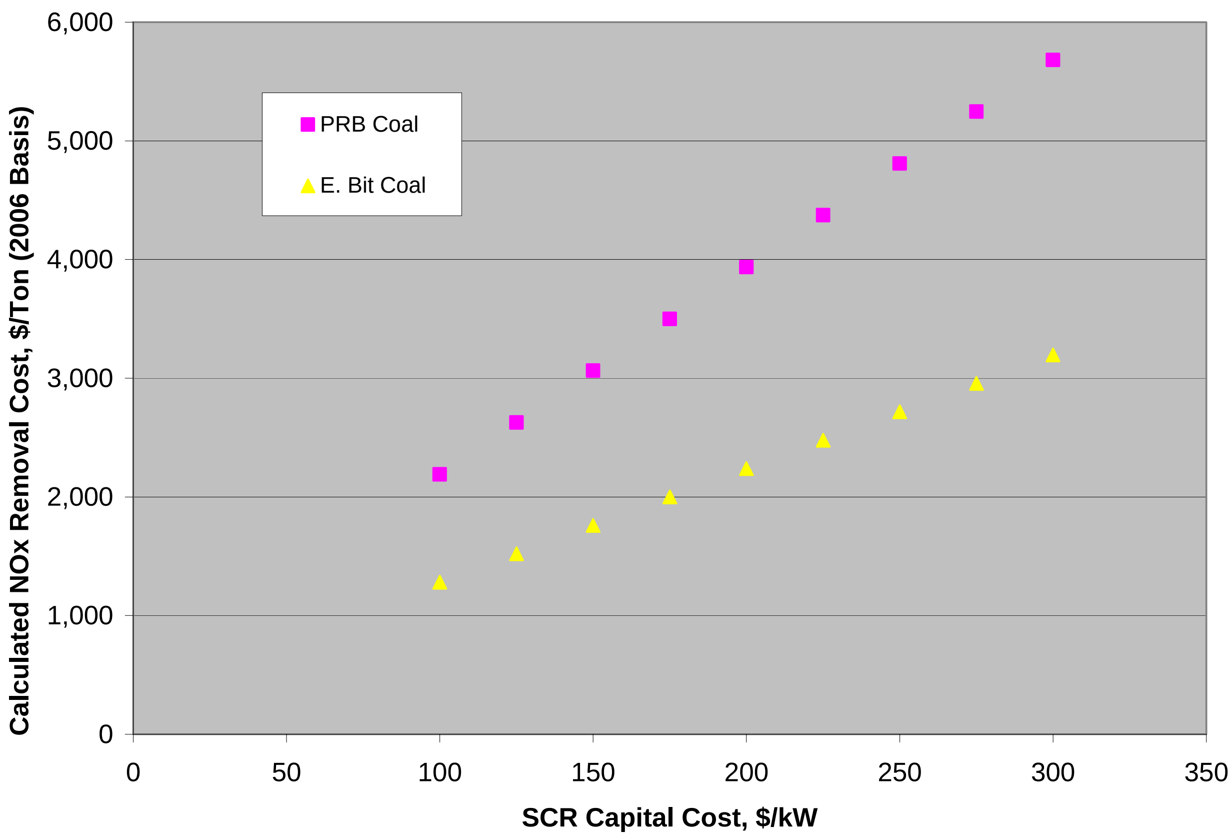

Figure 7-3. NOx Removal Cost per Ton ($/ton), Year 2006 Basis

SECTION 8

IMPLICATIONS FOR Hg CONTROL

This report has focused on cost and schedule issues attendant to the retrofit or construction of new FGD and SCR equipment. The Clean Air Mercury Rule (CAMR) also mandates installing control technology over the same time period. Although many units are anticipated to comply with Hg removal through wet FGD, the use of sorbent or activated carbon injection (ACI) upstream of an existing ESP or fabric filter (FF) may be needed.

EPA has projected the generating capacity that could be retrofit with ACI in FF to meet CAMR mandates (EPA, 2006). EPA's predictions suggest about 1,900 MW of ACI into FF could be deployed by 2010, with this amount increasing to 2,400 MW by 2015. EPA did not reveal details of its analysis. More importantly, EPA's analysis only addressed the federal CAMR and not the numerous state-specific initiatives, all of which are more strict than CAMR. As an example, the state of Georgia has proposed an emission control rule that at one site requires almost 3,300 MW of coal-fired capacity to be retrofit with fabric filters for particulate matter control (Georgia Environmental Protection Department, 2007). Consequently, EPA is likely under-predicting the utilization of ACI in FF by the utility industry.

The need for significant ACI/FF could further burden labor demand. A UARG analysis in 2003 assumed fabrication and installation of a typical FF would require 300 manhours of labor per MW of generating capacity, with half of that amount being boilermakers. The total of 150,000 manhours for a 500 MW unit, of which 75,000 are boilermakers, is small compared to the labor demand for SCR and FGD. However, the strained labor pool may not be able to accommodate any additional demand.

Finally, it should be noted that FF cost for use with ACI has escalated significantly since first proposed for Hg control. Specifically, early cost projections by EPRI suggested a FF retrofit cost of $50-60/kW, a value widely use by EPRI and adopted by UARG. Subsequently, experience from the Gaston trials in 2005 suggested design changes to improve Hg removal were warranted, such as using a lower air/cloth ratio (4-6 compared to 8-12) and thus higher filter area (Berry, 2004). This requirement, combined with a more complex equipment layout, has elevated capital estimates to more than $100/kW. The cost for 270 MW FF module for the Presque Isle station was $127/kW in 2004 dollars. This reference cost is used to project capital cost for larger units using conventional power-scaling law.

A recent study using Presque Isle as a reference design suggests typical FF costs are even higher, and approach $150/kW (EPRI, 2006). The degree that the design of the FF module at Presque Isle represents future applications is questioned by some, claiming the site characteristics atypically elevate cost. Presque Isle Units 7-9 do comprise a congested site, as effluent from three 90 MW units merge into one FF module. However, actual FF applications for Hg removal may incur these same challenges. In fact, the sites that could need ACI/FF for high Hg removal may be those not equipped with SCR and FGD, and be smaller, older generating units – exactly those represented by Presque Isle.

In summary, the need for at least several thousand MW and perhaps greater of ACI/FF will further exacerbate the schedule and cost pressures imposed by FGD and SCR.

SECTION 9

CONCLUSIONS

The significant demand for environmental controls for retrofit to existing units – combined with the construction of perhaps 80 GW of new coal-fired capacity – has elevated capital costs, both incurred and estimated. These escalated costs, combined with delays in installation due to equipment and personnel shortages, will challenge the ability of some operators to meet CAIR mandates. Further, the decision to comply using either control technology versus the purchase of emissions allowance may change over the timeframe from planning to execution.

Notably for FGD, the most recent capital cost data suggest a 30% increase over the last two years. Worldwide demand for material and personnel resources, combined with numerous and overlapping utility industry mandates, is believed responsible for this escalation. As depicted by the Vatavuk index reflecting scrubber costs presented in Section 4, FGD capital costs have increased at an annual rate of 7-9% for the past three years. These same cost pressures apply to SCR, and will also likely impact any large deployment of FF for use with ACI for future mercury emission controls.

These capital cost pressures could affect “scrub vs. switch” decisions. Specifically, the decision to “scrub” a coal with sulfur content of 6 lbs SO_2/MBtu may be based on preliminary engineering, and may adopt a FGD capital cost of \$200/kW with SO_2 reduction generated for \$250/ton. If actual construction costs increase to \$400/kW, SO_2 removal is provided for \$375/ton which may exceed the allowance price. The conclusions can be even more distorted for PRB coal, with an escalation in capital from \$250/kW to \$400/kW increasing SO_2 removal costs from \$1550 to more than \$2100/ton. Similar trends are noted in escalation of NOx compliance costs and the decision to deploy SCR NOx control versus another strategy.

This report revealed significant schedule pressures that threaten a utility company’s prospects of complying with CAIR mandates. In 2002, EPA presumed installation schedules for SCR and FGD were 21 and 27 months, respectively (EPA, 2002). UARG comments filed in response to this EPA claim offered more realistic schedules for SCR and FGD of 28 and 32 months, respectively (UARG, 2003).

The construction schedules have since been further extended. Specifically, SCR installation at present requires 36 months. Figure 9-1 presents a schedule for constructing the SCR for Associated Electric Co-Operatives New Madrid Unit 3, depicting a three-year duration from start to unit startup (Johnson, 2006). FGD schedules similarly extend to 36 months, or more if key items such reagent or slurry pumps cannot be acquired, or stacks erected.

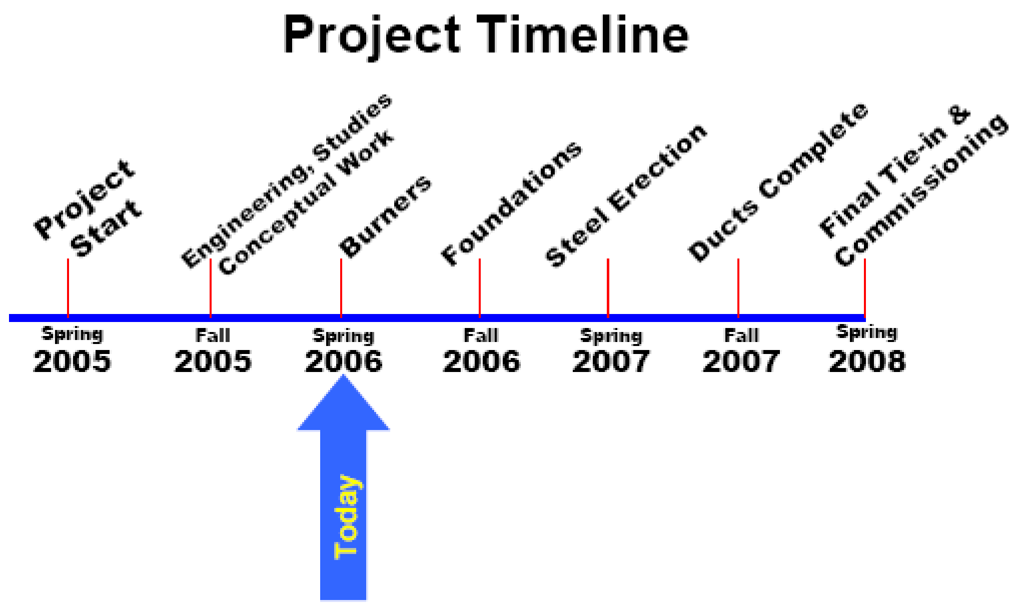

Figure 9-1. Project Timeline for New Madrid Unit 3 SCR Installation and Startup (after Johnson, 2006)

The combination of higher capital cost and extended installation schedules may prevent many owners from meeting compliance deadlines for CAIR or other initiatives. Particularly for smaller generating systems, access to the necessary technology may not be available, or only available at exorbitant costs. The case of South Mississippi Electric Power Association (SMEPA) is instructive regarding this item. In late 2006, SMEPA received bids for wet FGD and SCR equipment that specified a combined capital cost of about $1,000/kW for each unit. Although the small generating capacity of the host units (~200 MW each for two units) contributed to these costs, the extreme competition for resources and manpower are at least equally culpable. SMEPA is presently exploring alternative means to meet the CAIR mandates.

As a consequence, both the cost and schedule plans for FGD and SCR by many utility owners are at risk, compromising their ability to meet the numerous mandates.

SECTION 10

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SECTION 11

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July 10, 2007

Costs Surge For Building Power Plants

By MATTHEW L. WALD

General Electric called in reporters yesterday for a briefing on a nuclear plant it is trying to sell in partnership with Hitachi, a plant it said can be built faster than before, operated reliably and have a vanishingly small chance of an accident.

But what will it cost? After some hemming and hawing, company executives gave figures by the standard industry metric, dollars per kilowatt of capacity, but in a huge range: $2,000 to $3,000.

"There's massive inflation in copper and nickel and stainless steel and concrete," said John Krenecki, president and chief executive of GE Energy. The uncertainty is not just in nuclear plants, he said; coal plant prices are now similarly unstable.

As talk of building new power plants rises sharply, so does the cost. A new fleet of coal-fired power plants and a revival of nuclear construction after three decades are both looking tougher lately.

For example, in late 2004, Duke Energy, one of the country's largest utilities and most experienced builders, started planning a pair of coal-fired power plants to replace several built around the middle of the last century, at Cliffside, in western North Carolina. In May 2005, the company told regulators it wanted to spend $2 billion to build twin 800-megawatt units. But 18 months later, in November 2006, Duke said it would cost $3 billion. Then the state utility commission said to build only one of the plants, and in May of this year Duke said that would cost $1.83 billion, an increase of more than 80 percent from the original estimate.

Duke's experience may be extreme but it is hardly isolated.

"There's real sticker shock out there," Randy H. Zwirn, president of the Siemens Power Generation Group, said in an interview. He estimated that in the last 18 months, the price of a coal-fired power plant has risen 25 percent to 30 percent.

Part of the problem is huge price increases for the raw materials that plants are made from, including copper and nickel, which is what makes steel stainless. But the cost of finishing those commodities into components is also rising.

"There's a lack of production and manufacturing facilities in this country, and that may be partly to blame," said Jason Makansi, a consultant with Pearl Street, a consulting firm in St. Louis that specializes in electric utilities. But, he said, "the bigger culprit is the incredible demand in China and the rest of Asia."

"Basically everything is being sent over that way."

A result of demand in China and India, he said, is that "Duke and others want to build a new power plant based on inexpensive coal, but the capital cost to build that plant is doubling before they even put a shovel in the ground."

And other kinds of projects that use similar materials, everything from oil refineries to natural gas terminals, are competing for the same materials and labor, experts said. "So many industries are at cyclical peaks at the same time," Mr. Krenecki of G.E. said. "We can't forecast how long that will continue."

Mr. Makansi and others say a result is that consumers, already paying more for electricity because the price of coal and especially natural gas is up, will pay even more for new generating stations.

Duke was not surprised that prices were up, but realized when it actually took in bids from suppliers that the situation was worse than expected. Analysts say that the companies that make major plant components will gear up to meet new demand and eventually price increases will moderate. But James L. Turner, president and chief operating officer of Duke's United States electric and gas system, said the company could not wait for prices to reverse.

"Given customer needs and demand growth on our system, we don't have the luxury of waiting to see if it all settles down in a decade," he said, although the company says it would like to undertake more vigorous steps to cut demand through higher energy efficiency.

Duke was reluctant to discuss exactly what it was paying for major components. But Siemens, a supplier, gave some examples for a typical combined-cycle natural gas power plant, one that burns the fuel in a gas turbine to drive one generator, then makes steam from the exhaust to drive a second generator. The high-pressure piping for steam, used on a 293-megawatt plant, is up about 60 percent in the last two years, to about $1.12 million, according to the company. The equipment that uses exhaust heat to make steam, used at a 590-megawatt plant, is up about 40 percent in the last two years, $15.1 million in April of this year vs. $10.7 million in May 2005, according to Siemens.

Simply moving a 435,000-pound turbine for a 198-megawatt plant from factory to the plant site now runs about $100,000, according to Siemens, up from about $50,000 two years ago.

Nuclear plants still on the drawing board are also affected.

"For nuclear and for coal, we pretty much figure it's going to be about the same effect," said Revis James, an economist at the Electric Power Research Institute, a nonprofit consortium in Palo Alto, Calif. No matter what the technology, he said, "there's been a huge amount of change in the baseline estimates people are using."

Renewable energy is not immune. "Costs have increased for wind as they have for other technologies," said Christine Real de Azua, a spokeswoman for the American Wind Energy Association. "While wind farm operations are not hit by fuel price volatility, steep increases in the cost of raw materials like copper and steel and other factors have driven up the price of wind turbines," she said in an e-mail statement.

Her association recently republished data from a utility that buys large amounts of wind power, Puget Sound Energy, showing that prices in 2006 ranged from about 8 cents to 10.5 cents a kilowatt-hour, up from 2004, when it was 4.5 to 6 cents. A recent study by the National Renewable Energy Laboratory, part of the Department of Energy, showed a steadily declining price from 1999 to 2005, but an increase in 2006. The study said that wind power was generally competitive with other sources of energy but that rising costs were "starting to erode that value."

But the wind energy association said that competing technologies show even steeper increases.

All of this is bad news for efforts to slow climate change, experts say. Equipment to capture carbon dioxide from the smokestacks of power plants would be made of all the things that are rising in price: concrete, structural steel, steel vessels, valves and pipes. That equipment would require somewhat less of the most expensive components, the ones on the generation side that are meant to resist the highest temperatures, pressures and corrosive materials. But it would all be assembled by the same types of workers who are in short supply for building conventional power plants.

Appendix B

Details of Cost Calculation Using OAQPS Cost Manual

Objective: To develop SCR costs based on the OAQPS Cost Manual calculation

References:

1) EPA Air Pollution Control Cost Manual Section 4.2 NOx Post-Combustion Controls, Chapter 2 SCR, USEPA, Oct 2000

Assumptions:

a) None

Inputs:

	Parameter	Variable Name	Reference Information	Units	Value
a)	Fuel HHV	HV		Btu/lb	9,692
b)	Fuel burn rate	m-dot$_{fuel}$		lb/hr	594,098
c)	System capacity factor	CF_{Plant}		%	85
d)	SCR operating days	t_{SCR}		days/yr	365
e)	SCR inlet NOx	NOx_{in}		lb/MMBtu	0.3
f)	SCR outlet NOx	NOx_{out}		lb/MMBtu	0.07
g)	Stoichiometric ratio	ASR			1.05
h)	Fuel vol rate	q_{fuel}	ref. OAQPS	ft^3/min-MMBtu/hr	484
i)	SCR inlet temperature	T		F	650
j)	No. of SCR chambers	n_{SCR}			1
k)	Ammonial slip	Slip		ppm	2
l)	Fuel sulfure content	S		%	0.77
m)	Catalyst nominal height	h'_{layer}	ref. OAQPS	ft	3.1
n)	Spare catalyst layer	n_{empty}			1
o)	SCR height constant 1	c_1	ref. OAQPS		7
p)	SCR height constant 2	c_2	ref. OAQPS		9
q)	NH3 mol. weight	$M_{reagent}$			17.03
r)	NOx mol. weight	M_{NOx}			46.01
s)	NH3 solution concentration	Csol		%	29
t)	NH3 sol density	ρ_{sol}	for 29% NH3 at 60F - OAQPS	lb/ft^3	56
u)	NH3 sol spec. vol.	v_{sol}	for 29% NH3 at 60F - OAQPS	gal/ft^3	7.481
v)	NH3 storage days	t		days	30
w)	Retrofit SCR?	new	1=retrofit, 2=new		1
x)	SCR bypass?	bypass	1=yes, 2=no		1
y)	Catalyst cost per unit	$CC_{initial}$	ceramic honeycomb - OAQPS	\$/ft^3	240
z)	NH3 reagent cost	$Cost_{reagent}$		\$/lb	0.101
aa)	Pressure drop in duct	dP_{duct}			3
ab)	Pressure drop in cat.	$dP_{catalyst}$			1
ac)	Cost of power	$Cost_{elect}$	from PNM BART	\$/kWh	0.06095
ad)	Catalyst replacement	$CC_{replace}$	ceramic honeycomb - OAQPS	\$/ft^3	290
ae)	Annual interest rate	i	OAQPS	%	7
af)	Catalyst life	$h_{catalyst}$	OAQPS	hours	24,000
ag)	Payback period	n		years	20

Calculations:

Eqn. No.	Description	Variable Name	Equation	Units	Value
2.1	not used	--	--	--	--
2.2	not used	--	--	--	--
2.3	Boiler heat input	Q_B	HVm-dot$_{fuel}$	MMBtu/hr	5,758
2.4	not used	--	--	--	--
2.5	not used	--	--	--	--
2.6	System capacity factor	CF_{Plant}	(given)	%	85
2.7	not used	--	--	--	--
2.8	SCR capacity factor	CF_{SCR}	$t_{SCR}/365$	%	1
2.9	NOx removal	n_{NOx}	$(NOx_{in} - NOx_{out})/Nox_{in}$	%	0.77
2.10	Stoichiometric ratio	ASR	(given)		1.05
2.11	not used	--	--	--	--
2.12	Flue gas vol. flow rate	$q_{fluegas}$	$q_{fuel}Q_B(460+T)/(460+700)n_{SCR}$	acfm	2,786,871
2.13	not used	--	--	--	--
2.14	not used	--	--	--	--
2.15	not used	--	--	--	--
2.16	not used	--	--	--	--
2.16a	not used	--	--	--	--
2.17	not used	--	--	--	--
2.18	not used	--	--	--	--
2.19	Catalyst volume	$Vol_{catalyst}$	$2.81Q_Bn_{adj}Slip_{adj}NOx_{adj}S_{adj}T_{adj}/n_{SCR}$	ft^3	22,569
2.20	Adjusted NOx removal	n_{adj}	$0.2869+(1.058)(n_{NOx})$		1.10
2.21	Adjusted NOx inlet	NOx_{adj}	$0.8524+(0.3208)(NOx_{in})$		0.95
2.22	Adjusted NH3 slip	$Slip_{adj}$	1.2835-(0.0567)(Slip)	ppm	1.17
2.23	Adjusted coal sulfur	S_{adj}	0.9636+(0.0455)(S)		1.00
2.24	Adjusted flue gas temp	T_{adj}	$15.16-(0.03937)(T)+(2.74x10^{-5})(T^2)$		1.15
2.25	Catalyst area	$A_{catalyst}$	$q_{fluegas}/(16x60)$	ft^2	2,903
2.26	SCR cross-section area	A_{SCR}	$(1.15)(A_{catalyst})$	ft^2	3,338
2.27	SCR length or width	l = w	$(A_{SCR})^{1/2}$	ft	57.78
2.28	Catalyst layer number	n_{layer}	$Vol_{catalyst}/(h'_{layer} \times A_{catalyst})$		3
2.29	Catalyst layer height	h_{layer}	$Vol_{catalyst}/(n_{layer} \times A_{catalyst}) + 1$	ft	3.59
2.30	Total catalyst layer	n_{total}	$n_{layer} + n_{empty}$		4
2.31	SCR height	h_{SCR}	$n_{total}(c_1+h_{layer})+c_2$	ft	51.37

2.32	Reagent flow rate	$\text{m-dot}_{reagent}$	$NOx_{in}Q_BASRn_{NOx}M_{reagent}/M_{NOx}$	lb/hr	515
2.33	Aqueous NH3 flow rate	m-dot_{sol}	$\text{m-dot}_{reagent}/C_{sol}$	lb/hr	1,775
2.34	Aqueous NH3 vol rate	q_{sol}	$(\text{m-dot}_{sol}/p_{sol})v_{sol}$	gph	237
2.35	NH3 tank volume	Tank Vol	$q_{sol}t$	gal	170,709
2.36	Direct capital cost	DCC	$Q_B(3380+f(h_{SCR})+f(NH_{3rate})+f(new)))(3500/Q_B)^{0.35}+f(Vol_{catalyst})$	$	22,327,117
2.37	Adj for SCR height	$f(h_{SCR})$	$(6.12)h_{SCR}$ - 187.9	$/MMBtu/hr	126.46
2.38	Adj for NH3 flow rate	$f(NH_{3rate})$	$411(\text{m-dot}_{reagent}/Q_B)$-47.3	$/MMBtu/hr	-10.56
2.39	Adj for retrofit SCR	f(new)	dependent on retrofit/new	$/MMBtu/hr	0.00
2.40	not used	--	--	--	--
2.41	not used	--	--	--	--
2.42	Adj for SCR bypass	f(bypass)	dependent on bypass	$/MMBtu/hr	127.00
2.43	Initial catalyst charge	$f(Vol_{catalyst})$	$Vol_{catalyst}CC_{initial}$	$	5,416,521
2.44	Initial reagent cost	ICC	$Vol_{reagent}Cost_{reagent}$	$	129,065
2.45	Direct annual cost	DAC	AMC + ARC + AEC + ACRC	$/yr	3,458,228
2.46	Annual maintenance cost	AMC	0.015(TCI)	$/yr	473,340
2.47	Annual reagent cost	ARC	$q_{reagent}Cost_{reag}t_{op}$	$/yr	1,334,742
2.47a	Operation time	t_{ops}	$(CF_{plant})(8760)$	hr	7,446
2.48	Electric power	Power	$0.105Q_B(NOx_{in}n_{NOx}+0.5(dP_{duct}+n_{total}dP_{catalyst}))$	kW	2,255
2.49	Annual electricity cost	AEC	$(Power)(Cost_{elect})t_{op}$	$/yr	1,023,449
2.50	Cat replacement cost	CRC	$n_{SCR}Vol_{catalyst}CC_{replace}/R_{layer}$	$	2,181,654
2.51	Annual cat rep cost	ACRC	(CRC)(FWF)	$/yr	626,696
2.52	Future worth factor	FWF	$i(1/(1+i)^Y-1)$	%	0.29
2.53	Constant y	Y	$h_{catalyst}/t_{ops}$		3.22
2.54	Indirect Annual Cost	IDAC	(CRF)(TCI)	$/yr	2,978,663
2.55	Capital Recovery Factor	CRF	$(i(1+i)^n)/((1+i)^n-1)$	%	9.44
2.56	Total Annual Cost	TAC	DAC + IDAC	$/yr	6,436,891
2.57	NOx removed	NOx	$NOx_{in}n_{NOx}Q_Bt_{ops}$	ton	4,931
2.58	Cost effectiveness	CE	TAC/NOx	$/ton	1,306

Calculation of Capital Investment - OAQPS Method (No Adjustments)

Cost Parameter	Variable Name	Multiplier	Equation	(1998 $) Cost Amount	Escallation to 2007	B&V Estimate	Comments
Total Direct Capital Costs	**A**		**DCC**	**22,327,000**	**37,063,000**	**38,345,000**	
Indirect Installation Costs							
General facilities		0.05	A	1,116,000	1,853,000	1,917,000	
Engineering and home office fees		0.1	A	2,233,000	3,706,000	2,684,000	B&V used 7%
Process contingency		0.05	A	1,116,000	1,853,000	1,917,000	
Total Indirect Installation Costs	**B**		**0.05A + 0.10A + 0.05A**	**4,465,000**	**7,412,000**	**6,518,000**	
Project Contingency	C	0.15	(A+B)	4,018,800	6,671,000	8,973,000	B&V used 20%
Total Plant Costs	D		A + B + C	30,811,000	51,146,000	53,836,000	
Allowance for Funds During Construction	E		=0 (for SCR - OAQPS)	0	0	0	
Royalty Allowance	F		=0 (for SCR - OAQPS)	0	0	0	
Preproduction Cost	G	0.02	(D+E)	616,000	1,023,000	1,077,000	
Inventory Capital	H		ICC	129,000	129,000	129,000	
Initial Catalyst and Chemical	I		=0 (for SCR - OAQPS)	0	0	0	
Total Capital Investment	**TCI**		**D + E + F + G + H + I**	**31,556,000**	**52,298,000**	**55,042,000**	

Calculation of Capital Investment - OAQPS Method (Adjustment for Missing Scope)

Cost Parameter	Variable Name	Multiplier	Equation	Cost Amount	Escallation to 2007	B&V Estimate	Comments
Equipment Costs	EC					18,331,000	See original est
Installation Costs	IC					20,806,000	See original est
Total Direct Capital Costs from OAQPS	**A**		**DCC**	**22,327,000**	**37,062,820**	**39,137,000**	
Additions for Missing Scope on Direct Installation Costs							
Elevator	J		B&V Estimate Used		1,236,000	1,236,000	
SCR Bypass	K		B&V Estimate Used		10,000,000	10,000,000	
Nox Monitoring System	L		B&V Estimate Used		440,000	440,000	
Electrical Upgrades	M		B&V Estimate Used		484,000	484,000	
Instrumentation and Control System	N		B&V Estimate Used		291,000	291,000	
Subtotal of Missing Direct Capital Cost	CC		J+K+L+M+N		12,451,000	12,451,000	
Gross Receipt Tax	GRT	0.062	0.062 * (EC + CC)		1,848,000	1,908,000	From CUECost
Freight	FR	0.05	0.05 * (EC + CC)		1,491,000	1,539,000	From CUECost
Installation Costs on Missing Scope	IMS	1.135	1.135*(CC+GRT+FR)		17,922,000	18,044,000	
Air Preheater Modifications	Q		B&V Estimate Used		8,685,000	8,685,000	
Balanced Draft Conversion	R		B&V Estimate Used		17,122,000	17,122,000	
Site Preparation	S		B&V Estimate Used		2,000,000	2,000,000	
Buildings & Enclosures	T		B&V Estimate Used		500,000	500,000	
Total Cost of Missing Scope	**MS**		**CC+IMS+GRT+FR+Q+R+S+T**		**62,019,000**	**62,249,000**	
Total Direct Capital Costs with Adjustments	**DCCA**		**DCC+MS**		**99,081,820**	**101,386,000**	
Indirect Installation Costs							
General facilities		0.05	A		1,853,000	0	
Engineering and home office fees		0.1	A		3,706,000	0	
Engineering (B&V Calculation)		0.07	DCCA		0	7,097,000	CUECost method
Process contingency		0.05	A		1,853,000	0	
Total Indirect Installation Costs from OAQPS	**B**		**0.05A + 0.10A + 0.05A**		**7,412,000**	**7,097,000**	
Project Contingency	C	0.15	(A+CC+B)		8,539,000	0	
Project Contingency (B&V Calculation)	CBV	0.2	DCCA		0	20,277,000	CUECost method
Total Plant Costs	D		A+B+C		53,014,000	66,511,000	
Allowance for Funds During Construction	E		=0 (for SCR - OAQPS)		0	0	
Royalty Allowance	F		=0 (for SCR - OAQPS)		0	0	
Preproduction Cost	G	0.02	(D+E)		1,060,000	0	
Inventory Capital	H		ICC		0	0	
Initial Catalyst and Chemical	I		=0 (for SCR - OAQPS)		0	0	
Total Capital Investment	**TCI**		**D + E + F + G + H + I**		**54,074,000**	**66,511,000**	
Additions for Missing Scope on Indirect Costs							
Owner's Costs	OC	0.05	DCCA		4,954,000	5,069,000	
Construction Management	CM	0.10	DCCA		9,908,000	10,139,000	
Construction Indirects	CI		B&V Estimate		25,498,000	25,498,000	
Start-up and spare parts	SU	0.03	DCCA		2,972,000	3,042,000	
Performance Test	PT		B&V Estimate		200,000	200,000	
Total Cost of Missing Indirect Costs Scope	**MICS**		**OC+CM+CI+SU+PT**		**43,532,000**	**43,948,000**	
Subtotal of Indirect Costs	**IC**		**B+C+E+F+G+H+MICS**		**60,543,000**	**71,322,000**	
Interest During Construction	IDC	0.0741	See Note Below		$17,742,000	$19,196,000	CUECost Allows
Lost Generation During Outage	GEN		5 weeks @ 0.06095 $/kWh		23,674,000	23,674,000	
Total Capital Investment with Adjustments	**TCIA**		**DCCA + IC+IDC+GEN**		**201,040,820**	**215,578,000**	

Appendix C

Reference Equipment Quotations

4.1 and 4.2 Ammonia

Peerless Mfg. Co.

Firm Proposal #4222

Revision 0

submitted to

[redacted]

for the

Anhydrous Ammonia Storage & Handling System

for

[redacted]

in

[redacted]

RFQ: SSC-008-07

Proposal Date: November 2, 2006

BID FORM
PAGE 2

1. COMMON AND UNIT 2

	QUANTITY	UNIT PRICE	TOTAL PRICE
1.1 Anhydrous Ammonia Truck Unloading Skid Tag No. 9CGE-SKD-001	1 each	$66,600	$66,600
1.2 Anhydrous Ammonia Railcar Unloading Skid Tag No. 9CGE-SKD-002	1 each	$66,600	$66,600
1.3 Anhydrous Ammonia Unloading Compressor Skids Tag No. 9CGE-CMP-001, 9CGE-CMP-002	2 each	$55,500	$111,000
1.4 Anhydrous Ammonia Storage Tanks (77,100 gal) Tag No. 9CGE-TNK-001, 9CGE-TNK-002	2 each	$701,500	$1,403,000
1.5 Anhydrous Ammonia Forwarding Pumps Skid Tag No. 9CGE-P-001	1 each	$271,600	$271,600
1.6 Anhydrous Ammonia Vaporizer Skid (2x100%) Tag No. 9CGE-VAP-001	1 each	$183,200	$183,200
1.7 Anhydrous Ammonia Vaporizer Skid (including vaporizer accumulator), Tag No. 9CGE-VAP-002	1 each	$183,200	$183,200
1.8 Dilution Air & Ammonia Flow Control Skid Tag No. 9CGE-DIL-001	1 each	$194,600	$194,600
1.9 Personnel Protective Equipment	1 lot	$16,300	$16,300
1.10 Technical Assistance Time (10 days, 2 round trips)	1 lot	$18,600	$18,600
1.11 Rail Car Unloading Tower	1 each	$92,700	$92,700

TOTAL SECTION 1: $ 2,607,400

2. UNIT 1

	QUANTITY	UNIT PRICE	TOTAL PRICE
2.1 Anhydrous Ammonia Vaporizer Skid (including vaporizer accumulator), Tag No. 9CGE-VAP-003	1 each	$163,400	$163,400
2.2 Dilution Air & Ammonia Flow Control Skid Tag No. 9CGE-DIL-002	1 each	$174,200	$174,200

TOTAL SECTION 2: $ 337,600

TOTAL SECTIONS 1 - 2: $ 2,945,000 (excludes freight)

I. PRICE SUMMARY:

For a detailed description of each item listed below, please refer to Section IV.

ITEM	QUANTITY	DESCRIPTION	PRICE
		EQUIPMENT FOR COMMON AND UNIT #2	
A	1	Ammonia Truck Unloading Station	
B	1	Ammonia Railcar Unloading Station	
C	2	Compressor Stations	
D	2	77,100 gallon anhydrous ammonia storage tanks with ladder, platform, and instrumentation	
E	1	Ammonia forwarding pump skid	
F	1	Ammonia vaporization skid	
G	1	Ammonia vaporization skid	
H	1	Dilution air and ammonia flow control skid	
I	1 lot	Personnel protection equipment	
J	1 lot	Field Technical Assistance (2 trips, 10 days)	
		FIRM PRICE, EX-WORKS, MFG. POINT	**$2,607,400**
K	**OPTION**	**Adder** for freight to job site	$168,000
		EQUIPMENT FOR UNIT #1	
L	1	Ammonia vaporization skid	
		FIRM PRICE, EX-WORKS, MFG. POINT	**$337,600**
M	**OPTION**	**Adder** for freight to jobsite	$7,000
N	**OPTION**	**Adder** for a 10% Warranty bond valid for 2 years after delivery of equipment [for all items]	$7,000
		TOTAL – FIRM PRICE, F.O.B. JOB SITE	**$3,127,000**

All Purchase Orders based on this Quote, which is not an offer, are subject to acceptance by Seller at its principal office in Dallas, Texas. Unless otherwise expressly provided in Seller's acceptance, the terms and conditions set forth herein shall constitute a part of any agreement resulting from Seller's acceptance of an order for all or part of the goods covered by this Quote. This Quote serves as notice to Buyer of Seller's objection to any terms and conditions of Buyer that in any way conflict with, modify, condition, add to, or differ from the terms and conditions specified herein, unless such terms and conditions of Buyer are expressly included in Seller's acceptance of Buyer's order. Silence on the part of Seller shall not be construed, under any circumstances, as acceptance of Buyer's terms and conditions. If not previously revoked or otherwise provided herein, this Quote shall terminate and cease to exist thirty (30) days from the date of this Quote.

[redacted]
Applications Engineer

II. COMMERCIAL TERMS

4.3 Ductwork

Acknowledge receipt of this addendum on Page 1 of Bid Form.

BID FORM

[redacted]

PROCUREMENT DEPARTMENT

[redacted]

Invitation for Bids No: SSC-115-06

Company Name and Address

CIVES STEEL COMPANY

[redacted]

FAX No: [redacted]

EMAIL: [redacted]

Submit an original and one copy in bid envelope

[redacted]

This bid will be received at 12:00 p.m. and opened at 2:00 p.m., September 12, 2006 in the 6th floor Conference Room,

[redacted]

BID SECURITY REQUIREMENTS

[X]None required

[ ]Certified Check or Bond

$ ________ ________%

TERM OF CONTRACT

[X] One Time Purchase

[ ] Annual Requirements

[ ] Other, Specify________

SAMPLE REQUIREMENTS

[X] None required

[ ] Samples required prior to Bid Opening

[ ] Samples may be required subsequent to Bid Opening

SECTION 255.05, FLORIDA STATUTES CONTRACT BOND

[ ] None required

[X] Bond required $________ 100% of Bid Award

QUANTITIES

[ ] Quantities indicated are exacting

[X] Quantities indicated reflect the approximate quantities to be purchased throughout Contract period and are subject to fluctuation in accordance with actual requirements

INSURANCE REQUIREMENTS

[ ] None required

[X] Insurance required

Quote the following materials F.O.B.: Destination

Item No	ENTER HEREON YOUR BID FOR THE FOLLOWING DESCRIBED ARTICLES OR SERVICES	QUANTITY	UNIT PRICE	TOTAL
	See Page 2			

TOTAL $________

Bidder's Certification

We have received addenda 1 through 1

Handwritten Signature of Authorized Officer of Firm or Agent

[redacted]

Title

9-12-06

Date

[redacted]

Phone No.

1. UNIT PRICING

2.

	QUANITITY	UNIT PRICE MATERIAL COST	UNIT PRICE FABRICATION COST	TOTAL UNIT	TOTAL PRICE
A. Steel Plate (A588) with attached stiffeners (A588), corner angles, welds, bolts, ports, instrument connections and other required fabrication.	2,830 Tons	$0.52/LB	$0.88/LB	$1.40/LB	$7,924,000
B. 4" Internal pipe bracing (A335 P11) Including all necessary fabrication, gussets and welding	1 Ton	$2.50/LB_	$2.35/LB	$4.85/LB	$9,700
C. 6" Internal pipe bracing (A335 P11) including all necessary fabrication, gussets and welding	7 Tons	$1.96/LB_	$1.21/LB	$3.17/LB	$44,380
D. 8" Internal pipe bracing (A335 P11) including all necessary fabrication, gussets and welding	40 Tons	$1.95/LB	$1.05/LB	$3.00/LB	$240,000
E. 10" Internal pipe bracing (A335 P11) including all necessary fabrication, gussets and welding	23 Tons	$1.98/LB_	$0.96/LB	$2.94/LB	$135,240
F. 12" Internal pipe bracing (A335 P11) including all necessary fabrication, gussets and welding	10 Tons	$2.03/LB_	$0.88/LB	$2.91/LB	$58,200
G. Internal Turning Vanes (A588) including all necessary fabrication, welding, stiffening connections	260 Tons	$0.75/LB	$1.72/LB	$2.47/LB	$1,284,400
H. Detailing per hour	Hour	$______	$58.00		$______
I. Pressure instrumentation port including all necessary fabrication and welding	80 Each	$______	$309		$24,720
J. Instrumentation port including all necessary fabrication and welding	80 Each	$______	$206		$16,480
K. 6" x 1'-8" sample port including all necessary fabrication and welding	48 Each	$______	$361		$17,328

TOTAL SECTION: $9,754,448

Freight Costs are not to be included in the above pricing but will be evaluated as part of each Bidder's Unit Pricing. Please provide the following Unit Pricing, assuming 40,000lb/truck and that most of the truckloads will be configured as that listed in Item N below.

		UNIT PRICE
L. Truckload of legal freight	Each	$1,668
M. Truckload of freight 8'-7" wide up to 10'	Each	$2,168
N. Truckload of freight 10'-1" wide up to 12'	Each	$2,952

4.4 Expansion Joints

[redacted]
BID FORM
PROCUREMENT DEPARTMENT
[redacted]

Invitation for Bids No. SSC-019-07

Company Name and Address

Norflex, Inc
[redacted]

FAX No: [redacted]

Phone No: [redacted]

Submit an original and two copies in bid envelope
[redacted]

This bid will be opened at 2:00 p.m., November 28, 2006, in the 6th floor [redacted]

Please use typewriter when submitting prices on bid form.

BID SECURITY REQUIREMENTS
[X] None required
[ ] Certified Check or Bond
$ ______ ______%

TERM OF CONTRACT
[X] One Time Purchase
[ ] Annual Requirements
[ ] Other, Specify ______

SAMPLE REQUIREMENTS
[X] None required
[ ] Samples required prior to Bid Opening
[ ] Samples may be required subsequent to Bid Opening

SECTION 255.05, FLORIDA STATUTES CONTRACT BOND
[ ] None required
[X] Bond required $ ______ 10% of Bid Award

QUANTITIES
[X] Quantities indicated are exacting
[ ] Quantities indicated reflect the approximate quantities to be purchased throughout Contract period and are subject to fluctuation in accordance with actual requirements

INSURANCE REQUIREMENTS
[ ] None required
[X] Insurance required

Quote the following materials F.O.B.: [redacted]

Item No.	ENTER HEREON YOUR BID FOR THE FOLLOWING DESCRIBED ARTICLES OR SERVICES	QUANTITY	UNIT PRICE	TOTAL
	See Page 2 Insert total of section 1 and 2 from Bid Form page 2 below			

TOTAL $ 360,430

Bidder's Certification

By signing this bid form, the bidder agrees to follow, comply, and be bound by all Terms & Conditions contained in this IFB.

We have received addenda 1 through 4	W Thomas Norman Handwritten Signature of Authorized Officer of Firm or Agent	11/22/06 Date
	President Title	[redacted] Phone No

BID FORM
PAGE 2

1. Unit 1 Expansion Joints

	QUANTITY	UNIT OF MEASURE	PRICE
1.1 Economizer Outlet Expansion Joints	2	EA	$ 17,410
1.2 ByPass Inlet Expansion Joints	2	EA	$ 11,275
1.3 SCR Inlet Expansion Joints	2	EA	$ 12,390
1.4 SCR Outlet Expansion Joints	2	EA	$ 10,985
1.5 Outlet to Air Heater Expansion Joints	2	EA	$ 10,260
1.6 Air Heater Inlet Expansion Joints	2	EA	$ 10,220
1.7 ByPass to Air Heater	2	EA	$ 10,580
Radiography Weld Test	1	EA	$ 3,600
Freight	1	EA	$ 10,375
		TOTAL SECTION 1:	$180,215

2. Unit 2 Expansion Joints

	QUANTITY	UNIT OF MEASURE	PRICE
2.1 Economizer Outlet Expansion Joints	2	EA	$ 17,410
2.2 ByPass Inlet Expansion Joints	2	EA	$ 11,275
2.3 SCR Inlet Expansion Joints	2	EA	$ 12,390
2.4 SCR Outlet Expansion Joints	2	EA	$ 10,985
2.5 Outlet to Air Heater Expansion Joints	2	EA	$ 10,260
2.6 Air Heater Inlet Expansion Joints	2	EA	$ 10,220
2.7 ByPass to Air Heater	2	EA	$ 10,580
Radiography Weld Test	1	EA	3,600
Freight	1	EA	10,375
		TOTAL SECTION 2:	$ 180,215

TOTAL OF SECTIONS 1-2 $ 360,430

3. UNIT PRICING

Unit adjustment prices may be used to adjust the fixed lump sum price (additions or deletions) to compensate Supplier for modifications to the Work. Each unit adjustment price is the total of the specific unit of Work to be added to the Purchase Order price for net additions, or to be deleted from the Purchase Order price for net deletions. Unit adjustment pricing should include all associated overhead and profit markup.

Unit adjustment pricing is firm and remains valid for Purchaser's use to adjust the Purchase Order, commencing at the initial issue of the Purchase Order (the Effective Date), and extending to the end of the Warranty Period, unless otherwise stated or specified.

	QUANITITY	UNIT PRICE ADDITION	UNIT PRICE DELETION
A. 8" Expansion Joints, including all frames, welding, baffles, insulation pillows and hardware	1 LF	$ 93	$ 93
B. 12" Expansion Joints, including all frames, welding, baffles, insulation pillows and hardware	1 LF	$ 108	$ 108
C. Detailing per hour	Hour	$ 0	$ 0

4.6 Sonic Horns

[redacted]

BID FORM

Invitation for Bids No. SSC-029-07

Company Name and Address

GE Energy
[redacted]

FAX No: [redacted]

E-Mail : [redacted]

Submit an original and three copies in bid envelope to [redacted]

This bid will be opened at 2:00 p.m., December 12, 2006, in the 6th floor Conference Room, [redacted]

Please use typewriter when submitting prices on bid form

BID SECURITY REQUIREMENTS
[X] None required
[ ] Certified Check or Bond
$ ______ ______%

TERM OF CONTRACT
[X] One Time Purchase
[ ] Annual Requirements
[ ] Other, Specify______

SAMPLE REQUIREMENTS
[X] None required
[ ] Samples required prior to Bid Opening
[ ] Samples may be required subsequent to Bid Opening

SECTION 255.05, FLORIDA STATUTES CONTRACT BOND
[X] None required
[ ] Bond required $______ ____% of Bid Award

QUANTITIES
[X]Quantities indicated are exacting
[ ] Quantities indicated reflect the approximate quantities to be purchased throughout Contract period and are subject to fluctuation in accordance with actual requirements

INSURANCE REQUIREMENTS
[ ] None required
[X] Insurance required

Quote the following materials F.O.B.: [redacted]

Item No.	ENTER HEREON YOUR BID FOR THE FOLLOWING DESCRIBED ARTICLES OR SERVICES			
	Enter total of Sections 1 and 2 below			

TOTAL $275,022

Bidder's Certification

By signing this bid form, the bidder agrees to follow, comply, and be bound by all Terms & Conditions contained in this IFB.

We have received addenda ______ through ______

Mike Sedll
Handwritten Signature of Authorized Officer of Firm or Agent

12/8/06
Date

[redacted]
Title

[redacted]
Phone No.

Bid Form
Page 2

1. Unit 2 Acoustic Cleaner System

	Desc.	Quantitiy	Unit Price	Total Price
1.1	Unit 2 Sonic Horns	30 each	$ 2,850.00	$ 85,500.00
1.2	Mounting Ring/Flange	40 each	$ 275.00	$ 11,000.00
1.3	Blanking Plate	10 each	$ 60.00	$ 600.00
1.4	Solenoid Valve 3/4"	30 each	$ 275.00	$ 8,250.00
1.5	Flex Hose, 3/4"	30 each	$ 95.00	$ 2,850.00
1.6	Locking Ball Valve 3/4"	40 each	$ 113.00	$ 4,520.00
1.7	Wavegauge Verification System	30 each	$ 360.00	$ 10,800.00
*1.7.1	Power Supply for Wavegauge	2 each	$ 850.00	$ 1,700.00
1.8	Spare Parts	1 Lot	$ 970.00	$ 970.00
1.9	Pressure Regulating Valve and Outlet Pressure Gauge	8 each	$ 180.00	$ 1,440.00
*1.9.1	Locking Ball Valve 1-1/2"	8 each	$ 205.00	$ 1,640.00
1.10	Air Filter	2 each	$ 595.00	$ 1,190.00
*1.10.1	Differential Pressure Indicator	2 each	$ 120.00	$ 240.00
*1.10.2	Locking Ball Valve 1/2"	4 each	$ 89.00	$ 356.00
*1.10.3	Locking Ball Valve 2"	2 each	$ 345.00	$ 690.00
1.11	Unit 2 Sonic Horns Commissioning	1 Lot	N/C	N/C
*1.12	SS Equipment ID Tag Set	1 Lot	$ 1,215.00	$ 1,215.00
*1.13	SAMA Control Logic Diagrams	1 Lot	$ 1,500.00	$ 1,500.00
*1.14	Freight to Site (1A/2B/2A) Oct 07'	1 Lot	$ 3,550.00	$ 3,550.00
		Total Section 1:		$ 138,011.00

2. Unit 1 Acoustic Cleaner System

	Desc.	Quantitiy	Unit Price	Total Price
2.1	Unit 1 Sonic Horns	30 each	$ 2,850.00	$ 85,500.00
2.2	Mounting Ring/Flange	40 each	$ 275.00	$ 11,000.00
2.3	Blanking Plate	10 each	$ 60.00	$ 600.00
2.4	Solenoid Valve 3/4"	30 each	$ 275.00	$ 8,250.00
2.5	Flex Hose, 3/4"	30 each	$ 95.00	$ 2,850.00
2.6	Locking Ball Valve 3/4"	40 each	$ 113.00	$ 4,520.00
2.7	Wavegauge Verification System	30 each	$ 360.00	$ 10,800.00
*2.7.1	Power Supply for Wavegauge	2 each	$ 850.00	$ 1,700.00
2.8	Spare Parts	1 Lot	$ 970.00	$ 970.00
2.9	Pressure Regulating Valve and Outlet Pressure Gauge	8 each	$ 180.00	$ 1,440.00
*2.9.1	Locking Ball Valve 1-1/2"	8 each	$ 205.00	$ 1,640.00
2.10	Air Filter	2 each	$ 595.00	$ 1,190.00
*2.10.1	Differential Pressure Indicator	2 each	$ 120.00	$ 240.00
*2.10.2	Locking Ball Valve 1/2"	4 each	$ 89.00	$ 356.00
*2.10.3	Locking Ball Valve 2"	2 each	$ 345.00	$ 690.00
2.11	Unit 2 Sonic Horns Commissioning	1 Lot	N/C	N/C
*2.12	SS Equipment ID Tag Set	1 Lot	$ 1,215.00	$ 1,215.00
*2.13	SAMA Control Logic Diagrams	1 Lot	$ 1,500.00	$ 1,500.00
*2.14	Freight to Site (1B October 2008)	1 Lot	$ 2,550.00	$ 2,550.00
		Total Section 2:		$ 137,011.00

*** New lines added by Supplier to clarify complete scope of supply.**

4.7 Elevator

BID FORM

[redacted]

Invitation for Bids No. SCF-018-07

Company Name and Address	
KONE Inc. [redacted] FAX No: [redacted] EMAIL: [redacted]	Submit an original and three copies in bid envelope to [redacted] This bid will be received at 12:00 p.m. and opened at 2:00 p.m., November 28, 2006 in the 6th floor Conference Room, [redacted]

BID SECURITY REQUIREMENTS	TERM OF CONTRACT
[X] None required [ ] Certified Check or Bond $ ______ ______%	[X] One Time Purchase [ ] Annual Requirements [ ] Other, Specify______

SAMPLE REQUIREMENTS	SECTION 255.05, FLORIDA STATUTES CONTRACT BOND
[X] None required [ ] Samples required prior to Bid Opening [ ] Samples may be required subsequent to Bid Opening	[ ] None required [X] Bond required $______ 100% of Bid Award

QUANTITIES	INSURANCE REQUIREMENTS
[X] Quantities indicated are exacting [ ] Quantities indicated reflect the approximate quantities to be purchased throughout Contract period and are subject to fluctuation in accordance with actual requirements	[ ] None required [X] Insurance required

Quote the following materials F.O.B.: Destination

Item No.	ENTER HEREON YOUR BID FOR THE FOLLOWING DESCRIBED ARTICLES OR SERVICES	QUANTITY	UNIT PRICE	TOTAL
1.	Furnish Freight/Personnel Elevator	1		$ 583,720.00
2.	Installation of Elevator	1		$ 374,220.00

TOTAL $957,940.00

Bidder's Certification

We have received addenda 1 through 1	Handwritten Signature of Authorized Officer of Firm or Agent	12/12/06 Date
	[redacted] Title	[redacted] Phone No.

[redacted]

4.8 SCR Bypass

BID FORM

[redacted]

CONTRACTS DEPARTMENT

[redacted]

Invitation for Bids No. SSC-109-06

Company Name and Address

Submit an original and one copy in bid envelope to [redacted]

This bid will be opened at 2:00 p.m., September 7, 2006 in the 6th floor Conference Room, [redacted]

FAX No: ______________

BID SECURITY REQUIREMENTS

[X] None required
[ ] Certified Check or Bond
$ __________ __________%

TERM OF CONTRACT

[X] One Time Purchase
[ ] Annual Requirements with renewal options-three year with two one year renewals
[ ] Other, Specify ______________

SAMPLE REQUIREMENTS

[X] None required
[ ] Samples required prior to Bid Opening
[ ] Samples may be required subsequent to Bid Opening

SECTION 255.05, FLORIDA STATUTES CONTRACT BOND

[ ] None required
[X] Bond required ~~100% of Bid Award~~ See Commercial Clarification

QUANTITIES

[X] Quantities indicated are exacting
[ ] Quantities indicated reflect the approximate quantities to be purchased throughout Contract period and are subject to fluctuation in accordance with actual requirements

INSURANCE REQUIREMENTS

[ ] None required
[X] Insurance required
See Section V-Special Conditions

Quote the following materials F.O.B.: [redacted]

Item No	ENTER HEREON YOUR BID FOR THE FOLLOWING DESCRIBED ARTICLES OR SERVICES	QUANTITY	UNIT PRICE	TOTAL
	See Page 2			

DELIVERY WILL BE MADE WITHIN ~~X~~ See Attached Schedule DAYS FROM RECEIPT OF ORDER

TERMS OF PAYMENT: NET OR N/A % DISCOUNT N/A DAYS

(DISCOUNTS OFFERED FOR PAYMENT PERIODS OF LESS THAN 30 DAYS WILL NOT BE CONSIDERED IN MAKING AN AWARD)

Base Bid TOTAL $ 10,692,100

Alternate Bid Total $ 12,778,100

Bidder's Certification

We have received addenda 1 through 2

[signature] — Handwritten Signature of Authorized Officer of Firm or Agent

9/11/06 — Date

Vice President — Title

[redacted] — Phone No.

[redacted] BASE BID 9/11/06

BID FORM
PAGE 2

1. UNIT 1 EAST

	QUANTITY	UNIT PRICE	TOTAL PRICE
Inlet Diverter Damper (Tag No. 1CCE-DMP-1A1) including Inlet Diverter Damper Box, Inlet Diverter Damper Box Hopper (Tag Nos. 1ASC-HPR-1A-11, 1ASC-HPR-1A-12, 1ASC-HPR-1A-13, 1ASC-HPR-1A-14, 1ASC-HPR-1A-15, 1ASC-HPR-1A-16, 1ASC-HPR-1A-21, 1ASC-HPR-1A-22, 1ASC-HPR-1A-23, 1ASC-HPR-1A-24, 1ASC-HPR-1A-25, 1ASC-HPR-1A-26)	1ea	$1,122,300	$1,122,300
SCR Bypass Outlet Expansion Joint (Tag No. 1CCE-EXJ-1A3)	1ea	$20,275	$20,275
Inlet Maintenance Damper (Tag No. 1CCE-DMP-1A2) including Inlet Maintenance Damper Box	1ea	$640,700	$640,700
Outlet Isolation Damper, (Tag No. 1CCE-DMP-1A3)	1ea	$165,000	$165,000
Outlet Maintenance Damper (Tag No. 1CCE-DMP-1A4) including Outlet Maintenance Damper Box	1ea	$672,500	$672,500
LPA Screen, (Tag No. 1CCE-SCN-1A) * NO BID AT THIS TIME DUE TO LACK OF INFO	1ea	$ —	$ —

TOTAL SECTION 1: $2,620,775

2. UNIT 1 WEST

	QUANTITY	UNIT PRICE	TOTAL PRICE
Inlet Diverter Damper (Tag No. 1CCE-DMP-1B1) including Inlet Diverter Damper Box, Inlet Diverter Damper Box Hopper (Tag Nos. 1ASC-HPR-1B-11, 1ASC-HPR-1B-12, 1ASC-HPR-1B-13, 1ASC-HPR-1B-14, 1ASC-HPR-1B-15, 1ASC-HPR-1B-16, 1ASC-HPR-1B-21, 1ASC-HPR-1B-22, 1ASC-HPR-1B-23, 1ASC-HPR-1B-24, 1ASC-HPR-1B-25, 1ASC-HPR-1B-26)	1ea	$1,122,300	$1,122,300
SCR Bypass Outlet Expansion Joint (Tag No. 1CCE-EXJ-1B3)	1ea	$20,275	$20,275
Inlet Maintenance Damper (Tag No. 1CCE-DMP-1B2) including Inlet Maintenance Damper Box	1ea	$640,700	$640,700
Outlet Isolation Damper (Tag No. 1CCE-DMP-1B3)	1ea	$165,000	$165,000
Outlet Maintenance Damper (Tag No. 1CCE-DMP-1B4) including Outlet Maintenance Damper Box	1ea	$672,500	$672,500
LPA Screen, (Tag No. 1CCE-SCN-1B) * NO BID AT THIS TIME	1ea	$ —	$ —

TOTAL SECTION 2: $2,620,775

3. UNIT 1 SEAL AIR FAN

	QUANTITY	UNIT PRICE	TOTAL PRICE
Fan, Tag No. 1CCE-FAN-1	1ea	$	$
Fan, Tag No. 1CCE-FAN-2	1ea	$	$
Fan, Tag No. 1CCE-FAN-3	1ea	$	$
Isolation Damper, Tag No. 1CCE-DMP-1	1ea	$	$
Isolation Damper, Tag No. 1CCE-DMP-2	1ea	$	$
Isolation Damper, Tag No. 1CCE-DMP-3	1ea	$	$

TOTAL SKID ⇒ TOTAL SECTION 3: $97,500

[redacted] BASE BID 9/11/06

BID FORM
PAGE 3

4. UNIT 1 CONSULTING FIELD TIME

	QUANTITY	UNIT PRICE	TOTAL PRICE
1 round trip, 2 days for installation	1 lump sum	NA	$ 3,000
1 round trip, 3 days for damper start-up	1 lump sum	NA	$ 4,000

TOTAL SECTION 4: $ 7,000

5. UNIT 2 EAST

	QUANTITY	UNIT PRICE	TOTAL PRICE
Inlet Diverter Damper (Tag No. 2CCE-DMP-2A1) including Inlet Diverter Damper Box, Inlet Diverter Damper Box Hopper (Tag Nos. 2ASC-HPR-2A-11, 2ASC-HPR-2A-12, 2ASC-HPR-2A-13, 2ASC-HPR-2A-14, 2ASC-HPR-2A-15, 2ASC-HPR-2A-16, 2ASC-HPR-2A-21, 2ASC-HPR-2A-22, 2ASC-HPR-2A-23, 2ASC-HPR-2A-24, 2ASC-HPR-2A-25, 2ASC-HPR-2A-26)	1ea	$1,122,300	$ 1,122,300
SCR Bypass Outlet Expansion Joint (Tag No. 2CCE-EXJ-2A3)	1ea	$ 20,275	$ 20,275
Inlet Maintenance Damper (Tag No. 2CCE-DMP-2A2) including Inlet Maintenance Damper Box	1ea	$ 640,700	$ 640,700
Outlet Isolation Damper (Tag No. 2CCE-DMP-2A3)	1ea	$ 165,000	$ 165,000
Outlet Maintenance Damper (Tag No. 2CCE-DMP-2A4) including Outlet Maintenance Damper Box	1ea	$ 672,500	$ 672,500
LPA Screen, (Tag No. 2CCE-SCN-1A) * NO BID AT THIS TIME	1ea	$ —	$ —

TOTAL SECTION 5: $ 2,620,775

6. UNIT 2 WEST

	QUANTITY	UNIT PRICE	TOTAL PRICE
Inlet Diverter Damper (Tag No. 2CCE-DMP-1B1) including Inlet Diverter Damper Box, Inlet Diverter Damper Box Hopper (Tag Nos. 2ASC-HPR-2B-11, 2ASC-HPR-2B-12, 2ASC-HPR-2B-13, 2ASC-HPR-2B-14, 2ASC-HPR-2B-15, 2ASC-HPR-2B-16, 2ASC-HPR-2B-21, 2ASC-HPR-2B-22, 2ASC-HPR-2B-23, 2ASC-HPR-2B-24, 2ASC-HPR-2B-25, 2ASC-HPR-2B-26)	1ea	$1,122,300	$ 1,122,300
SCR Bypass Outlet Expansion Joint (Tag No. 2CCE-EXJ-2B3)	1ea	$ 20,275	$ 20,275
Inlet Maintenance Damper (Tag No. 2CCE-DMP-2B2) including Inlet Maintenance Damper Box	1ea	$ 640,700	$ 640,700
Outlet Isolation Damper (Tag No. 2CCE-DMP-2B3)	1ea	$ 165,000	$ 165,000
Outlet Maintenance Damper (Tag No. 2CCE-DMP-2B4) including Outlet Maintenance Damper Box	1ea	$ 672,500	$ 672,500
LPA Screen, (Tag No. 2CCE-SCN-1B) * NO BID at This Time	1ea	$ —	$ —

TOTAL SECTION 6: $ 2,620,775

[redacted] BASE BID 9/11/06 [illegible]

BID FORM
PAGE 4

7. UNIT 2 SEAL AIR FAN

	QUANTITY	UNIT PRICE	TOTAL PRICE
Fan, Tag No. 2CCE-FAN-1	1ea	$_____	$_____
Fan, Tag No. 2CCE-FAN-2	1ea	$_____	$_____
Fan, Tag No. 2CCE-FAN-3	1ea	$_____	$_____
Isolation Damper, Tag No. 2CCE-DMP-1	1ea	$_____	$_____
Isolation Damper, Tag No. 2CCE-DMP-2	1ea	$_____	$_____
Isolation Damper, Tag No. 2CCE-DMP-3	1ea	$_____	$_____

TOTAL SKID ⇒ TOTAL SECTION 7: $97,500

8. UNIT 1 CONSULTING FIELD TIME

	QUANTITY	UNIT PRICE	TOTAL PRICE
1 round trip, 2 days for installation	1 lump sum	NA	$ 3,000
1 round trip, 3 days for damper start-up	1 lump sum	NA	$4,000

TOTAL SECTION 8: $ 7,000

TOTAL OF SECTIONS 1-8 $ 10,692,100

9. OPTION PRICING

The Supplier shall quote the Work (base scope) exactly as specified in the RFQ documents. The following Option Pricing is submitted by Supplier for consideration of Purchaser. Option Pricing shall be itemized in corresponding fields as additions to, or deletions from, Supplier's pricing for the base scope defined in the RFQ documents. Option Pricing remains valid for Purchaser's acceptance only until the initial issue of the Purchaser Order, unless otherwise specified.

	QUANITITY	TOTAL PRICE
A. Hazardous classification Class I Div II for Seal Air Fans as location is not definite and may fall within Ammonia Vaporization Skid hazardous radius.	1 lump sum	$ NO BID at This TIME

4.9 Structural Steel

144805.61.4001 Structural Cost Estimate Summary

Item	Pay Code	Estimated Quantity	Unit	Unit price Material Cost	Unit price Fabrication Cost	Total price	Remarks
Beams							
	B1	15	ton	$900	$5,014	$88,710	Approx. qty.
	B2	55	ton	$900	$4,017	$270,435	
	B3	150	ton	$900	$1,453	$352,950	
	B4	250	ton	$900	$992	$473,000	
	B5	200	ton	$900	$808	$341,600	
	B6	385	ton	$910	$731	$631,785	
	B7	150	ton	$920	$653	$235,950	
	B8	190	ton	$965	$610	$299,250	
	B9	10	ton	$1,500	$504	$20,040	
Columns						$0	
	C1	5	ton	$900	$5,327	$31,135	Approx. qty.
	C2	5	ton	$900	$4,558	$27,290	Approx. qty.
	C3	10	ton	$900	$2,713	$36,130	Approx. qty.
	C4	15	ton	$900	$1,610	$37,650	
	C5	35	ton	$900	$724	$56,840	
	C6	50	ton	$940	$609	$77,450	
	C7	50	ton	$940	$520	$73,000	
	C8	400	ton	$940	$465	$562,000	
	C9	177	ton	$940	$435	$243,375	
	C10	608	ton	$1,500	$403	$1,157,024	
Plate Girders						$0	
	PG1	440	ton	$1,500	$2,195	$1,625,800	
	PG2	120	ton	$1,500	$1,366	$343,920	Approx. qty.
Built-Up Members						$0	
	BU	25	ton	$1,500	$1,902	$85,050	Approx. qty.
Horizontal Bracing						$0	
	H1	20	ton	$1,300	$3,968	$105,360	
	H2	20	ton	$1,300	$2,933	$84,660	
	H3	65	ton	$1,400	$1,753	$204,945	
	H4	30	ton	$1,500	$1,455	$88,650	
	H5	15	ton	$900	$1,300	$33,000	
	H6	35	ton	$980	$1,137	$74,095	
	H7	15	ton	$980	$976	$29,340	Approx. qty.
	H8	10	ton	$980	$823	$18,030	Approx. qty.
Vertical Bracing						$0	
	V1	10	ton	$1,300	$4,956	$62,560	Approx. qty.
	V2	15	ton	$1,300	$3,472	$71,580	Approx. qty.
	V3	30	ton	$1,400	$2,357	$112,710	
	V4	120	ton	$1,500	$2,048	$425,760	
	V5	250	ton	$900	$1,598	$624,500	
	V6	200	ton	$980	$1,277	$451,400	
	V7	50	ton	$980	$1,123	$105,150	
	V8	375	ton	$980	$969	$730,875	
	V9	35	ton	$1,300	$864	$75,740	Approx. qty.

Monorail (S-Shapes)						$0	
	S1	20	ton	$1,600	$2,672	$85,440	
	S2	7	ton	$1,800	$1,925	$26,075	
	S3	5	ton	$1,800	$1,468	$16,340	Approx. qty.
	S4	0	ton	$1,800	$1,169	$0	Approx. qty.
Stair Stringers						$0	
	SS	45	ton	$1,450	$2,593	$181,935	
Hangers (W-Shaped)						$0	
	HG1	5	ton	$900	$3,386	$21,430	Approx. qty.
Hangers (Angles)						$0	
	HG2	5	ton	$900	$4,874	$28,870	Approx. qty.
Structural Posts (W-Shapes)						$0	
	SP1	10	ton	$900	$3,330	$42,300	Approx. qty.
Structural Posts (Angles)						$0	
	SP2	10	ton	$900	$3,091	$39,910	Approx. qty.
Structural Posts (Pipes)						$0	
	SP4	10	ton	$1,400	$3,670	$50,700	Approx. qty.
Base Plates (Loose)						$0	
	BP	5	ton	$1,500	$3,039	$22,695	Approx. qty.
						$0	
Girts-Shapes						$0	
	GS1	5	ton	$900	$4,696	$27,980	Approx. qty.
	GS2	10	ton	$900	$2,952	$38,520	
	GS3	10	ton	$900	$1,437	$23,370	Approx. qty.
	GS4	5	ton	$900	$1,128	$10,140	Approx. qty.
Miscellaneous Plates						$0	
	MP	158	ton	$1,300	$2,631	$621,098	
Grating						$0	
	G1	79400	SF	$10.10	n/a	$801,940	
	GT	7500	EA	$31.50	n/a	$236,250	Approx. qty.
Guard Rail						$0	
	HR	13440	LF	$55.10	n/a	$740,544	
	SG	1500	EA	$315.00	n/a	$472,500	Approx. qty.
Ladders w/cage						$0	
	L1	60	LF	$120.00	n/a	$7,200	
	L2	60	LF	$42.75	n/a	$2,565	Approx. qty.
Bolt Assemblies						$0	
	BLT1	20000	LB	$2.25	n/a	$45,000	Approx. qty.
DTI						$0	
	DTI	2500	100 LOT	$65.00	n/a	$162,500	Approx. qty.
					TOTAL	**$14,074,040**	**for 2 units**
						$7,037,020	**per unit**

[redacted]
Project

Addendum 1

[redacted]

Structural Steel

31 July 2006

BASE BID: UNIT PRICES w/ DRAFTING INCLUDED

[redacted]

05120 - Structural Steel Unit Prices

~~26~~ 31 July 2006

Item	Pay Code[1]	Pay Category				Estimated Quantity	Unit Price ($/Unit)[2]			
							Unit	Material Cost	Fabrication Cost Painted	Fabrication Cost Galvanized
Beams										
	B1	0	To	12	lb/ft	Later	Ton	$900	$5014	N/A
	B2	13	To	20	lb/ft	55	Ton	$900	$4017	N/A
	B3	21	To	40	lb/ft	150	Ton	$900	$1453	N/A
	B4	41	To	80	lb/ft	250	Ton	$900	$992	N/A
	B5	81	To	100	lb/ft	200	Ton	$900	$808	N/A
	B6	101	To	150	lb/ft	385	Ton	$910	$731	N/A
	B7	151	To	200	lb/ft	150	Ton	$920	$653	N/A
	B8	201	To	350	lb/ft	190	Ton	$965	$610	N/A
	B9	351	And	Over	lb/ft	10	Ton	$1500	$504	N/A
Columns										
	C1	0	To	12	lb/ft	Later	Ton	$900	$5327	N/A
	C2	13	To	20	lb/ft	Later	Ton	$900	$4558	N/A
	C3	21	To	40	lb/ft	Later	Ton	$900	$2713	N/A
	C4	41	To	80	lb/ft	15	Ton	$900	$1610	N/A
	C5	81	To	100	lb/ft	35	Ton	$900	$724	N/A
	C6	101	To	150	lb/ft	50	Ton	$940	$609	N/A
	C7	151	To	200	lb/ft	50	Ton	$940	$520	N/A
	C8	201	To	350	lb/ft	400	Ton	$940	$465	N/A
	C9	351	To	~~450~~ 398	lb/ft	~~375~~177	Ton	$940	$435	N/A
	C10	~~451~~ 399	And	Over	lb/ft	~~410~~608	Ton	$1500	$403	N/A
Plate Girders[4]										
	PG1	STG - PLATE GIRDER 1				440	Ton	$1500	$2195	N/A
	PG2	STG - PLATE GIRDER 2				Later	Ton	$1500	$1366	N/A
Built-Up Members[4]										
	BU	W-SHAPE & CHANNELS				Later	Ton	$1500	$1902	N/A
Horizontal Bracing[3]										
	H1	0	To	12	lb/ft	20	Ton	$1300	$3968	N/A

[redacted] 05120 - Structural Steel Unit Prices ~~26~~ 31 July 2006										
							Unit Price ($/Unit)[2]			
Item	**Pay Code[1]**	**Pay Category**				**Estimated Quantity**	**Unit**	**Material Cost**	**Fabrication Cost Painted**	**Fabrication Cost Galvanized**
	H2	13	To	20	lb/ft	20	Ton	$1300	$2933	N/A
	H3	21	To	40	lb/ft	65	Ton	$1400	$1753	N/A
	H4	41	To	80	lb/ft	30	Ton	$1500	$1455	N/A
	H5	81	To	100	lb/ft	15	Ton	$900	$1300	N/A
	H6	101	To	150	lb/ft	35	Ton	$980	$1137	N/A
	H7	151	To	200	lb/ft	Later	Ton	$980	$976	N/A
	H8	201	And	Over	lb/ft	Later	Ton	$980	$823	N/A
Vertical Bracing										
	V1	0	To	12	lb/ft	Later	Ton	$1300	$4956	N/A
	V2	13	To	20	lb/ft	Later	Ton	$1300	$3472	N/A
	V3	21	To	40	lb/ft	30	Ton	$1400	$2357	N/A
	V4	41	To	80	lb/ft	120	Ton	$1500	$2048	N/A
	V5	81	To	100	lb/ft	250	Ton	$900	$1598	N/A
	V6	101	To	150	lb/ft	200	Ton	$980	$1277	N/A
	V7	151	To	200	lb/ft	50	Ton	$980	$1123	N/A
	V8	201	To	350	lb/ft	375	Ton	$980	$969	N/A
	V9	351	And	Over	lb/ft	Later	Ton	$1300	$864	N/A
Monorails (S-Shapes)										
	S1	13	To	20	lb/ft	20	Ton	$1600	$2672	N/A
	S2	21	To	40	lb/ft	7	Ton	$1800	$1925	N/A
	S3	41	To	80	lb/ft	Later	Ton	$1800	$1468	N/A
	S4	80	And	Over	lb/ft	Later	Ton	$1800	$1169	N/A
Stair Stringers										
Painted	SS					45	Ton	$1450	$2593	N/A
Hangers (W-Shapes)										
	HG1					Later	Ton	$900	$3386	N/A
Hangers (Angles)										
	HG2					Later	Ton	$900	$4874	N/A

Addendum 1

[redacted]
Project

[redacted]

Structural Steel

31 July 2006

[redacted]

05120 - Structural Steel Unit Prices
~~26~~ 31 July 2006

Item	Pay Code[1]	Pay Category				Estimated Quantity	Unit Price ($/Unit)[2]			
							Unit	Material Cost	Fabrication Cost Painted	Fabrication Cost Galvanized
Structural Posts[8] (W-Shapes)										
	SP1					Later	Ton	$900	$3330	N/A
Structural Posts (Angles)										
	SP2					Later	Ton	$900	$3091	N/A
Structural Posts (Pipes)										
	SP4					Later	Ton	$1400	$3670	N/A
Base Plates (Loose)										
	BP					38	Ton	$1500	$3039	N/A
Girts - Shapes[6]										
	GS1	0	To	12	lb/ft	Later	Ton	$900	$4696	N/A
	GS2	13	To	20	lb/ft	10	Ton	$900	$2952	N/A
	GS3	21	To	40	lb/ft	Later	Ton	$900	$1437	N/A
	GS4	41	To	80	lb/ft	Later	Ton	$900	$1128	N/A
Miscellaneous Plates[10]										
	MP					158	Ton	$1300	$2631	N/A
Grating										
1 ¼"x3/16" 19W4	G1					79400	SF	$10.10	N/A	
Grating Treads	GT~~G2~~					Later	EA~~SF~~	$31.50	N/A	
Guard Rail										
Galv'd Handrails	HR					13440	LF	$55.10	N/A	
Galv'd Safety Gates	SG					Later	EA	$315	N/A	
Ladders, w/Cage										
Galv'd	L1					60	LF	$120.00	N/A	

[redacted]

05120 - Structural Steel Unit Prices
~~26~~ 31 July 2006

Item	Pay Code[1]	Pay Category		Estimated Quantity	Unit Price ($/Unit)[2]			
					Unit	Material Cost	Fabrication Cost Painted	Fabrication Cost Galvanized
Ladders, w/o Cage								
Galv'd	L2			Later	LF	$42.75	N/A	
Bolt Assemblies[6]								
	BLT1	DIA = 7/8	Grade = A325	Later	LB	$2.25	N/A	N/A
	BLT2	DIA = ???	Grade = A325	Later	LB	Later	N/A	N/A
	BLT3	DIA = ???	Grade = A490	Later	LB	Later	N/A	N/A
	BLT4	DIA = ???	Grade = A490	Later	LB	Later	N/A	N/A
DTIs								
	DTI1	FOR 7/8 DIA, A325 BOLTS		Later	100 Lot [11]	$65.00	N/A	N/A
	DTI2	FOR ??? DIA, A325 BOLTS		Later	100 Lot [11]	Later	N/A	N/A
	DTI3	FOR ??? DIA, A490 BOLTS		Later	100 Lot [11]	Later	N/A	N/A
	DTI4	FOR ??? DIA, A490 BOLTS		Later	100 Lot [11]	Later	N/A	N/A

Notes:

1.) Pay code followed by " - P" for painted, " - G" for galvanized and " - N" for none.

2.) The unit prices shall include all costs for furnishing the designated unit of material complete, including all associated engineering and design costs, procurement, fabrication, overtime, overhead, profit mark-up and shipping to the jobsite. The unit prices shall not be subject to change solely because of greater or lessor total quantities than anticipated. The unit price for a member shall be based upon the weight of the principal member of the fabricated, rolled, or built-up structural shape. The cost for connection angles, gussets, attached baseplates and any other shop assembled (bolted or welded) appurtenances shall be included in the unit price for the principal member to which they are attached. Bolts, nuts, washers and DTIs shall be priced separately.

3.) Horizontal bracing shall be WT-shapes, double angles, or W-shapes. Include the price of double angle spacer plates in the horizontal bracing cost.

4.) See drawings for truss, plate girder and built-up member details.

5.) Girt shape pricing shall include all costs for sag rods and connection materials. Girt shapes shall be channels or angles or built-up W- shape and channel members.

6.) Bolt assemblies include one heavy hex nut and two hardened washers per bolt. Unit pricing for bolt assemblies shall be inclusive of bolts, nuts and washers

7.) Materials shall be as noted in the attached specification and drawings.

8.) W-shape posts are differentiated from columns because they are either supported by a beam rather than a concrete foundation, or are supported by a concrete foundation, but have a total member weight less than 300 lbs.

9.) Anchor Rods Shall Include All Nuts, Washers And Other Appurtenances.

10.) Miscellaneous shapes and plates include loose materials not attached to the structural frame, nor identified elsewhere on this list. such materials include sole plates, bearing plates, cover plates, lintels, etc.

[redacted]
05120 - Structural Steel Unit Prices
~~26~~ 31 July 2006

Item	Pay Code[1]	Pay Category	Estimated Quantity	Unit Price ($/Unit)[2]			
				Unit	Material Cost	Fabrication Cost Painted	Fabrication Cost Galvanized
11.) 100 Lot indicates 100 pieces. When the unit of measurement is a 100 Lot, the pricing shall be total price for 100 pieces.							

BASE BID: UNIT PRICES w/ DRAFTING INCLUDED

Note: The above material cost unit prices are for raw mill steel materials, F.O.B. our plant , [redacted]

4.10 NOx Monitoring

[redacted]
PROCUREMENT DEPARTMENT
[redacted]

BID FORM

Invitation for Bids No.

Company Name and Address

[redacted]

FAX No: [redacted]

Phone No: [redacted]

Submit an original and three copies in bid envelope to [redacted]

This bid will be opened at 2:00 p.m., January 9, 2007, in the 6th floor Conference Room, [redacted]

Please use typewriter when submitting prices on bid form.

BID SECURITY REQUIREMENTS

[X] None required
[ ] Certified Check or Bond
$ ________ ________%

TERM OF CONTRACT

[X] One Time Purchase
[ ] Annual Requirements
[ ] Other, Specify ________

SAMPLE REQUIREMENTS

[X] None required
[ ] Samples required prior to Bid Opening
[ ] Samples may be required subsequent to Bid Opening

SECTION 255.05, FLORIDA STATUTES CONTRACT BOND

[X]None required
[ ]Bond required $ ________ of Bid Award

QUANTITIES

[X] Quantities indicated are exacting
[ ] Quantities indicated reflect the approximate quantities to be purchased throughout Contract period and are subject to fluctuation in accordance with actual requirements

INSURANCE REQUIREMENTS

[ ] None required
[X] Insurance required

Quote the following materials F.O.B.: [redacted]

Item No.	ENTER HEREON YOUR BID FOR THE FOLLOWING DESCRIBED ARTICLES OR SERVICES	QUANTITY	UNIT PRICE	TOTAL
	ENTER TOTAL OF SECTIONS 1 -3 BELOW.			

TOTAL **$779,450**

Bidder's Certification

By signing this bid form, the bidder agrees to follow, comply, and be bound by all Terms & Conditions contained in this IFB.

We have received addenda 1 through 2

Handwritten Signature of Authorized Officer of Firm or Agent

Product Manager
Title

January 22, 2007
Date

[redacted]
Phone No.

BID FORM
PAGE 2

	Quantity	Price
1. Unit 1 System		
Unit 1 NOx Monitoring System	1 Lot	**$287,013 (per item #1-14 in Scope of Supply)**
Unit 1 Technical Assistance Provide pricing for Technical Assistance as follows: (5 days and 1 round trip per unit)		
Unit 1 – TA	1 Lot	**$7,394 (per Item #15 in Scope of Supply)**
Unit 1 - Field Certification Testing	1Lot	**$26,267 (per Item #16 in Scope of Supply)**

(Bidder shall provide Field Certification Testing per Unit, per the requirements stated in Section 11505.2.6 Field testing in the technical specification).

	Total Section 1	**$320,674**

	Quantity	Price
2. Unit 2 System		
Unit 2 NOx Monitoring System	1 Lot	**$287,013 (per Item #17-30 in Scope of Supply)**
Unit 2 Technical Assistance Provide pricing for Technical Assistance as follows: (5 days and 1 round trip per unit)		
Unit 2 – TA	1 Lot	**$7,394 (per Item #31 in Scope of Supply)**
Unit 2 - On Site Training	Price per class	**$6,101 (per Item #32 in Scope of Supply)**

(Bidder shall provide a price for two (2) training classes to be conducted at the plant site. The classes shall be approx. 8 hours per class and taught on consecutive days at the plant site. Each class will have up to 15 attendees. Bidder shall be responsible for all coordination, materials, and training services for these two class dates. See Section 11505.2.10 of the technical specification). This training will suffice for both Unit 1 and 2 training.

Unit 2 - Field Certification Testing	1Lot	**$26,267 (per Item #33 in Scope of Supply)**

(Bidder shall provide Field Certification Testing per Unit, per the requirements stated in Section 11505.2.6 Field testing in the technical specification).

	Total Section 2	**$326,776**

3. Three Year Maintenance Contract	1 Lot	**$132,000** **(per Item #34 in Scope of Supply)**
Per Technical Section 11505.2.11	**Total Section 3**	**$132,000**

4. Unit Pricing

Unit adjustment prices may be used to adjust the fixed lump sum price (additions or deletions) to compensate Supplier for modifications to the Work. Each unit adjustment price is the total of the specific unit of Work to be added to the Purchase Order price for net additions, or to be deleted from the Purchase Order price for net deletions. Unit adjustment pricing should include all associated overhead and profit markup.

Unit adjustment pricing is firm and remains valid for Purchaser's use to adjust the Purchase Order, commencing at the initial issue of the Purchase Order (the Effective Date), and extending to the end of the Warranty Period, unless otherwise stated or specified.

Additional Sample Line	Price per foot	**$34**

Manufacturer's Field TA (Technical Assistance) Services – all-inclusive daily per diem rate shall include all salary and overhead, local lodging, travel between the jobsite and local lodging, meals, and miscellaneous expenses. One day of consulting field time shall be defined as one, twelve (12) hour onsite workday in which all project construction and management personnel are working normal shifts. Consulting Field Time does not include any manual labor.

A. Monday through Friday (up to 12 hours)	$/hour	**$150**
B. Saturday (up to 12 hours)	$/hour	**$225**
C. Sunday / Holiday (up to 12 hours)	$/hour	**$300**

Adjustment Rate – all inclusive rate to adjust the above per diem rates for hours worked beyond an twelve (12) hour onsite workday:

D. Monday through Friday (beyond-12 hours)	$/hour	**$225**
E. Saturday (beyond 12 hours)	$/hour	**$300**
F. Sunday / Holiday (beyond 12 hours)	$/hour	**$350**

Round Trip Rate – shall include all expenses traveling to and returning from the lodging local to the jobsite, from the Supplier's home base of operation. This all-inclusive rate shall include all transportation (air and/or ground), parking, tolls, meals, travel per diem, and salary/overhead while traveling, and other miscellaneous expenses associated with one round trip.

G. Round Trip Rate	$/rt	**$1,000**

Daltec Industries Ltd.

[redacted]

April 4, 2007

[redacted]

Attention: Carol Logan

RE: Invitation to Bid 020807CL
[redacted]

With respect to the specifications provided, Daltec Industries is pleased to offer the following equipment for your consideration:

Offering
Inlet Fans:
4 only – Daltec Model HP50W-1822 Arrangement 8, Class 22K HD Industrial Fans. Each fan is complete with:

- Inlet and Outlet Flanges
- Galvanized OSHA Shaft and Coupling Guards
- Drive Coupling
- Construction suitable for 850 degF operation
- Shaft Seal
- Housing Drain
- Cooling Disk
- Radiation Shield
- Inlet and Outlet to 6" diameter
- Inlet and Outlet Manual Butterfly Dampers
- Inlet and Outlet Expansion Joints
- Mechanical run test prior to shipment
- QA to ISO 9001: 2000 standards with documentation
- 3HP/3/60/460/3600RPM Motor

Price (each) ....$7635.00 USD

Outlet Fans:
4 only – Daltec Model HP100W-2430 Arrangement 8, Class 19K HD Industrial Fans. Each fan is complete with:

- Inlet and Outlet Flanges
- Galvanized OSHA Shaft and Coupling Guards
- Drive Coupling
- Construction suitable for 850 degF operation
- Shaft Seal
- Housing Drain
- Cooling Disk
- Radiation Shield
- Inlet and Outlet to 6" diameter
- Inlet and Outlet Manual Butterfly Dampers
- Inlet and Outlet Expansion Joints

. . ./2

- Mechanical run test prior to shipment
- QA to ISO 9001: 2000 standards with documentation
- 3HP/3/60/460/1800RPM Motor

Price (each) .... $9920.00 USD

Terms
Prices quoted are FOB Daltec's Plant, Guelph Ontario
All applicable freight costs are extra

Delivery
Drawings for approval .... 1-2 weeks after receipt of an order
Certified Drawings .... 4 weeks after approval
Equipment (ex-works) .... 8 –10 weeks after approval
Documentation .... with shipment

Notes
1. Welding will be to CWB (Canadian Welding Bureau) standards, not AWS as specified
2. The inlet fans have been selected for the operating point which yielded the largest fan diameter

We would like to thank you for this opportunity to offer our equipment and hope you find the quotation acceptable. If you have any questions please do not hesitate in contacting the writer.

Yours truly,
DALTEC INDUSTRIES LTD

Vaj Beg

4.11 Electrical Upgrades

GE Industrial C & I, [redacted]

Prop.# 6F4-291130V, 10/29/2007, GEXPORO Supply Co.

46 1 Brkr, Molded Case (135B)
THED136050WL
3 POLE 600VAC 50A BREAKER

47 1 Brkr, Molded Case (135B)
THED136050WL
3 POLE 600VAC 50A BREAKER

REQUIRE BKR ONLY
1-THJK436175WL

48 1 Fastrac Units (GO100MZ)
MFB175SFLT
8000 Series MCC Feeder Breaker Unit
480 Volts 60Hz
42000 SC Rating
18" SFLT Type 175 Amps Trip Feeder C/B

49 1 Brkr, Molded Case (135B)
THED136030WL
3 POLE 600VAC 30A BREAKER

Add

50 1 Fastrac Units (GO100MZ)
FK06
8000 Series MCC Door Filler Kit
6" Door Filler Kit

52 1-THJK436250WL BKR
53 1-THED136030WL BKR
54 1-THJK436250WL BKR
IN A 12" BUCKET
55 1-6" Filler Kit
204B4145AMG1

51 1 Fastrac Units (GO100MZ)
FK06
8000 Series MCC Door Filler Kit
6" Door Filler Kit

Total Lot Price **$128,988.00**

ATTACHMENT A - Request for Proposal
Medium Voltage VFD's – BID FORM

TM GE Bid Form – 2/21/07

Unit 1	Quantity	Unit Price	Extended Price
1.1 Controls Upgrade for FD Fan VFD's (see details and options in proposal letter)	3 each	110,800.00	332,400.00
1.2 Variable Frequency Drive System (4 for Unit 1 plus 1 spare)	5 each	779,967.00	3,899,835.00
1.3 Option with GE Medium Voltage Synchronous Motors to power ID Fans	4 each	819,660-.00	3,278,640.00
1.3 Option with Ideal Medium Voltage Synchronous Motors to power ID Fan	4 each	690,350.00	2,761,400.00
Total Unit 1			
Unit 2	Quantity		
2.1 Controls Upgrade for FD Fan VFD's	3 each	110,800.00	332,400.00
2.2 Variable Frequency Drive System (4 for Unit 2 plus 1 spare)	5 each	779,967.00	3,899,835.00
2.3 Option with GE Medium Voltage Synchronous Motors to power ID Fans	4 each	819,660-.00	3,278,640.00
2.3 Option with Ideal Medium Voltage Synchronous Motors to power ID Fans	4 each	690,350.00	2,761,400.00
Total Unit 2			
Total Units 1 and 2 with GE Motors			15,021,750.00
Option Pricing:			
3.1 Harmonic Analysis of the system	1 Lot	Per Unit	18,000.00
3.2 Training for up to 10 supervisor / engineering personnel	1 Lot	Per unit	18,900.00
3.3 Training for up to 10 maintenance / service personnel	1 Lot	Per Unit	20,450.00
3.4 24 hour x 7 day remote monitoring service (for 3 years of unlimited number of cases)	1 Lot	Per Unit	83,170.00

only use these.

Request for Proposal
Secondary Unit Substation (SUS) – BID FORM

Unit 1	Quantity	UOM	Unit Price	
U1 480V SCR PC Switchgear 1C3/1A7	1	each	179,000	00
U1 480V SCR PC Transformer 1C3	1	each	70,000	00
U1 480V SCR PC Transformer 1A7	1	each	70,000	00
Total Unit 1				
Unit 2	Quantity	UOM	Unit Price	
U2 480V SCR PC Switchgear 2C3/2A7	1	each	179000	00
U2 480V SCR PC Transformer 2C3	1	each	70,000	00
U2 480V SCR PC Transformer 2A7	1	each	70,000	00
Total Unit 2				
Total Units 1 and 2				

UNIT PRICING

Unit adjustment prices may be used to adjust the fixed lump sum price (additions or deletions) to compensate Supplier for modifications to the Work. Each unit adjustment price is the total of the specific unit of Work to be added to the Purchase Order price for net additions, or to be deleted from the Purchase Order price for net deletions. Unit adjustment pricing should include all associated overhead and profit markup.

Unit adjustment pricing is firm and remains valid for Purchaser's use to adjust the Purchase Order, commencing at the initial issue of the Purchase Order (the Effective Date), and extending to the end of the Warranty Period, unless otherwise stated or specified.

Unit Price Adjustment*	Quantity	UOM	Add / Delete Unit Price
800AF Manual Breaker	Per	each	12,000.00
800AF Electric Breaker	Per	each	13,500.00

[redacted]

4.12 Instrumentation and Control System

[redacted]
PROCUREMENT DEPARTMENT
[redacted]

BID FORM

Invitation for Bids No.

Company Name and Address
Metso Automation MAX Controls, Inc.
[redacted]

FAX No: [redacted]

Phone No: [redacted]

Submit an original and two copies in bid envelope
to [redacted]

This bid will be opened at 2:00 p.m., November 21, 2006, in the 6th floor Conference Room, [redacted]

Please use typewriter when submitting prices on bid form.

BID SECURITY REQUIREMENTS

[X] None required
[ ] Certified Check or Bond
$ ________ ________%

TERM OF CONTRACT

[X] One Time Purchase
[ ] Annual Requirements
[ ] Other, Specify________

SAMPLE REQUIREMENTS

[X] None required
[ ] Samples required prior to Bid Opening
[ ] Samples may be required subsequent to Bid Opening

SECTION 255.05, FLORIDA STATUTES CONTRACT BOND

[X]None required
~~[X]Bond required~~ $________ 100% of Bid Award

QUANTITIES

[X] Quantities indicated are exacting
[ ] Quantities indicated reflect the approximate quantities to be purchased throughout Contract period and are subject to fluctuation in accordance with actual requirements

INSURANCE REQUIREMENTS

[ ] None required
[X] Insurance required

Quote the following materials F.O.B.: [redacted]

Item No.	ENTER HEREON YOUR BID FOR THE FOLLOWING DESCRIBED ARTICLES OR SERVICES	QUANTITY	UNIT PRICE	TOTAL
	See Page 2 - 3			

TOTAL $________

Bidder's Certification

By signing this bid form, the bidder agrees to follow, comply, and be bound by all Terms & Conditions contained in this IFB.

We have received addenda -- through -- (none received)

Roger A. Leimbach
Handwritten Signature of Authorized Officer of Firm or Agent

Vice President, Marketing and Applications
Title

December 7, 2006
Date

[redacted]
Phone No.

BID FORM
PAGE 2

UNIT 1

		QUANTITY	TOTAL PRICE
1.	Unit 1 Engineering	1 lump sum	$121,300.00
2.	Unit 1 Technical Assistance Time including 45 days and ~~three~~ four round trips	1 lump sum	$113,600.00

TOTAL OF SECTION 1 **$234,900.00**

UNIT 2

		QUANTITY	TOTAL PRICE
3.	Unit 2 Engineering	1 lump sum	$327,900.00
4.	Unit ~~3~~ 2 Technical Assistance Time including 45 days and ~~three~~ four round trips	1 lump sum	$107,300.00

TOTAL OF SECTION 2 **$435,200.00**

OPTION PRICING

The Supplier shall quote the Work (base scope) exactly as specified in the RFQ documents. The following Option Pricing is submitted by Supplier for consideration of Purchaser. Option Pricing shall be itemized in corresponding fields as additions to, or deletions from, Supplier's pricing for the base scope defined in the RFQ documents. Option Pricing remains valid for Purchaser's acceptance only until the initial issue of the Purchaser Order, unless otherwise specified.

		QUANTITY	TOTAL PRICE
5.	a. Unit 1 three day Factory Acceptance Test (on-site)	1 lump sum	$48,000.00
	b. Update existing Training Simulator to include SCR	1 lump sum	$39,100.00
	c. Tag Out Application (Units 1&2)	1 lump sum	$37,400.00

UNIT PRICING

Unit adjustment prices may be used to adjust the fixed lump sum price (additions or deletions) to compensate Supplier for modifications to the Work. Each unit adjustment price is the total of the specific unit of Work to be added to the Purchase Order price for net additions, or to be deleted from the Purchase Order price for net deletions. Unit adjustment pricing should include all associated overhead and profit markup.

Unit adjustment pricing is firm and remains valid for Purchaser's use to adjust the Purchase Order, commencing at the initial issue of the Purchase Order (the Effective Date), and extending to the end of the Warranty Period, unless otherwise stated or specified.

Manufacturer's Field Technical Services – all-inclusive daily per diem rate shall include all salary and overhead, local lodging, travel between the jobsite and local lodging, meals, and miscellaneous expenses. One day of consulting field time shall be defined as one, twelve (12) hour onsite workday in which all project construction and management personnel are working normal shifts. Consulting Field Time does not include any manual labor.

	QUANITITY	UNIT PRICE ADDITION	UNIT PRICE DELETION
A. Monday through Friday (~~up to 12 hours~~ 8 AM to 5 PM)	$/hour	$136.00	$129.00
B. Saturday (~~up to 12 hours~~ 8 AM to 5 PM)	$/hour	$204.00	$ N/A
C. Sunday / Holiday (~~up to 12 hours~~ 8 AM to 5 PM)	$/hour	$272.00	$ N/A

Note: Time worked in excess of 40 hours per week, excluding Sundays and Holidays will be billed at 1.5 times the base rate. No Travel or Living expenses are included in these rates. Travel and Living expenses would be billed at cost plus 10 percent.

PRICE BREAKDOWN

UNIT 1

		QUANTITY	TOTAL PRICE
1.	Unit 1 Engineering	1 lump sum	$ 87,420
2.	Unit 1 Hardware	1 lump sum	$ 49,103
3.	Unit 1 Technical Assistance Time including 10 days and two round trip	1 lump sum	$ 15,380

TOTAL OF SECTION 1 **$ 151,903**

UNIT 2

		QUANTITY	TOTAL PRICE
4.	Unit 2 Engineering	1 lump sum	$ 122,275
5.	Unit 2 Hardware	1 lump sum	$ 49,103
6.	Unit 3 Technical Assistance Time including 10 days and two round trip	1 lump sum	$ 15,380

TOTAL OF SECTION 2 **$ 186,758**

OPTION PRICING

The Supplier shall quote the Work (base scope) exactly as specified in the RFQ documents. The following Option Pricing is submitted by Supplier for consideration of Purchaser. Option Pricing shall be itemized in corresponding fields as additions to, or deletions from, Supplier's pricing for the base scope defined in the RFQ documents. Option Pricing remains valid for Purchaser's acceptance only until the initial issue of the Purchaser Order, unless otherwise specified.

		QUANTITY	TOTAL PRICE
7.	Unit 1 one day Factory Acceptance Test	1 lump sum	$ 2,784
8.	Unit 1 redundant bridge controller	1 lump sum	$ 6,492
9.	Unit 2 redundant bridge controller	1 lump sum	$ 6,492

UNIT PRICING

Unit adjustment prices may be used to adjust the fixed lump sum price (additions or deletions) to compensate Supplier for modifications to the Work. Each unit adjustment price is the total of the specific unit of Work to be added to the Purchase Order price for net additions, or to be deleted from the Purchase Order price for net deletions. Unit adjustment pricing should include all associated overhead and profit markup.

Unit adjustment pricing is firm and remains valid for Purchaser's use to adjust the Purchase Order, commencing at the initial issue of the Purchase Order (the Effective Date), and extending to the end of the Warranty Period, unless otherwise stated or specified.

Manufacturer's Field Technical Services – all-inclusive daily per diem rate shall include all salary and overhead, local lodging, travel between the jobsite and local lodging, meals, and miscellaneous expenses. One day of consulting field time shall be defined as one, twelve (12) hour onsite workday in which all project construction and management personnel are working normal shifts. Consulting Field Time does not include any manual labor.

	QUANITITY	UNIT PRICE ADDITION	UNIT PRICE DELETION
A. Monday through Friday (up to 12 hours)	$/hour	$ 156	$ 152
B. Saturday (up to 12 hours)	$/hour	$ 234	$ 152
C. Sunday / Holiday (up to 12 hours)	$/hour	$ 312 / $ 468	$ 152