Economics of Lime and Limestone for Control of Sulfur Dioxide

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ABSTRACT

Over 90% of U.S. flue gas desulfurization system capacity uses lime or limestone. This trend will likely continue into the next phase of federally mandated SO_2 reduction from coal burning power plants. The paper will present results of life-cycle cost analyses of major FGD processes that use lime and limestone including wet limestone with forced-oxidation (LSFO), wet magnesium-enhanced lime, and dry/semi-dry lime.

This paper will show the relative competitive position of limestone and lime-based processes relative to reagent cost, auxiliary power cost, coal sulfur content, dispatch, capital cost, and by-product production. The information presented here is based on a study performed by Sargent & Lundy and sponsored by the National Lime Association. The full report is available on the National Lime Association web site:
http://www.lime.org/NLADryFGD.pdf
http://www.lime.org/Wet_FGD.pdf

INTRODUCTION

Sargent & Lundy LLC performed a study to compare costs of leading lime and limestone-based flue gas desulfurization (FGD) processes utilized by power generating plants in the United States. The study included developing conceptual designs with capital and O&M cost requirements using up-to-date performance criteria for the processes. This paper provides a summary of results of the study.

Four FGD processes were evaluated: wet limestone scrubbing with forced oxidation (LSFO), wet lime scrubbing using magnesium-enhanced lime (MEL) with forced oxidation, dry lime scrubbing using a conventional spray-dryer absorber, and dry lime scrubbing using a circulating fluid bed (CFB) absorber. Each process was evaluated for a 500 MW coal-fired generating unit. The first three processes account for over 85% of FGD capacity in the United States. The fourth process, dry lime CFB, uses a newer type of absorber which has been more widely used in

Europe. There was interest in evaluating dry scrubbing using this absorber because of its claims of increased SO_2 removal efficiency and reduced cost and complexity compared with a conventional spray dryer absorber.

A specific purpose of the study was to provide a cost comparison between wet lime and wet limestone technology that takes into account recent improvements in these technologies. Wet limestone systems have been substantially improved in the last decade resulting in improved performance and reliability and reduced capital and operating costs. Examples of such improvements include use of a single absorber module for power generating units with capacity of 500 MW and greater and increased sulfur dioxide removal efficiency to greater than 95%.

Wet magnesium-enhanced lime systems have also been substantially improved. The MEL process now includes production of wallboard-quality gypsum via ex-situ forced oxidation, which results in a large reduction in operating cost compared with the predecessor MEL throwaway process. Since 1997, 4300 MW of MEL capacity have been retrofitted to produce gypsum. Single absorber modules have been utilized for power generating units of 500 MW and greater. New absorber installations have taken advantage of the lower L/G requirements inherent in the MEL process to substantially reduce absorber size and cost.

SO_2 removal efficiencies evaluated in the study reflect improvements in SO_2 removal capability of both wet and dry FGD processes. Design removal efficiency of 98% was chosen for wet FGD evaluation, and 93 to 95% removal was chosen for dry FGD depending on process and coal type. For new coal-fired plants operating on high-sulfur coal with wet FGD, a 98% removal design may be required to meet Best Available Control Technology emission limits. For new coal-fired plants operating on low-sulfur coal with dry FGD, 93-95% removal may likewise be required. For retrofit application of wet FGD where removal requirements have traditionally depended on the value of SO_2 allowances, an increasing value of allowances would be expected to increase desired removal efficiency above 95%..For this reason, a removal efficiency of 98% was chosen for this study. Also, 98% reduction was chosen to be the same for retrofit as for new unit application of wet FGD to allow better comparison between these cases.

Additional aspects of the study included: development of design criteria; determination of application limits (absorber module size, coal sulfur content vs. SO_2 removal efficiency); performance expectations for SO_2 removal, reagent utilization, byproduct quality, parasitic power consumption; design considerations and costs for FGD application in new power generating units versus retrofit to existing units; and advantages and disadvantages of wet and dry technologies.

Capital costs were developed primarily from Sargent & Lundy's cost database, which is continuously updated from ongoing work in the area of FGD.

Coal types used in the evaluations included high-sulfur Appalachian, low-sulfur Appalachian, and low-sulfur Powder River Basin (PRB). The wet FGD systems were evaluated on both Appalachian coals, while the dry FGD systems were evaluated on the low-sulfur coals. Table 1 shows composition of these coals.

Table 1. Compositions of Coals Used in Study of FGD Processes

Coal Type	**High-sulfur Appalachian**	**Low-sulfur Appalachian**	**Low-sulfur PRB**
FGD process type evaluated	Wet	Wet, Dry	Dry
Fuel analysis, % wt.:			
Sulfur	3.0	1.3	0.6
Chlorine	0.12	0.1	0.03
High heating value, Btu/lb	12,720	13,100	8,335
SO_2 generation*, lb/Mbtu	4.72	2.0	1.44

* All sulfur in coal is assumed to be converted to SO_2, and that no sulfur is removed in the either the bottom ash or electrostatic precipitator ash.

EVALUATION OF FGD PROCESSES

The following sections include description of the wet and dry processes, lime and limestone types utilized, byproducts, and commercial status of each.

FGD Process Description

Wet FGD

Wet FGD technology using limestone or lime as a reagent has been the FGD technology most frequently selected for sulfur dioxide (SO_2) reduction from coal-fired utility boilers. A wet FGD flue gas treatment system is usually located after removal of particulate matter from flue gas by an electrostatic precipitator or baghouse. Cleaned gas is discharged to a stack. Both LSFO and MEL are considered commercially mature technology and are offered by a number of suppliers.

LSFO and MEL processes are well known and described in detail in the study and elsewhere. Compositions of limestone and magnesium-enhanced lime required are well known. Both processes produce gypsum byproduct utilized in wallboard production and other uses. Unlike the recycle tank oxidation common in the LSFO process, in the MEL process, forced oxidation to produce gypsum is accomplished in a reactor separate from the absorber recycle tanks . This “ex-situ” oxidation is desirable in the MEL process to maintain a high concentration in absorber slurry of soluble magnesium sulfites which buffer pH during SO_2 absorption. Presence of this buffer allows reduced liquid-to-gas ratio and depresses scaling tendency. A second MEL process by-product, magnesium hydroxide, can be produced by treating FGD wastewater with additional lime. Use of this byproduct for control of sulfur trioxide emissions via furnace injection has been demonstrated in 800 MW and 1300 MW units.

Besides reagent, a significant difference between LSFO and MEL is the required absorber liquid-to-gas ratio to achieve the required SO_2 removal efficiency which results in a significantly different parasitic power consumption for each of the technologies. An important goal of this study was to quantify the impact that selection of reagent (limestone or lime) would have on capital cost, operations & maintenance costs and combined life cycle costs for the LSFO and MEL processes.

The LSFO system evaluated in the study did not include use of organic acids. LSFO systems are usually designed without depending on use of organic acids such as DBA. Advantages of organic acid addition are ability to reduce L/G and reduced power consumption. Provision is sometimes included to allow future organic acid addition in case SO_2 collection efficiency is inadequate. Disadvantages include additional operating cost, uncertainty in long-term supply and pricing of DBA by-products, possible contamination of gypsum by-product, biological oxygen demand in wastewater, and potential increased wastewater treatment cost.

Dry FGD

The dry FGD process using a spray dryer absorber is well known and described elsewhere.

The CFB absorber is relatively new to the U.S. market. In a typical CFB absorber flue gas is treated in the absorber by mixing flue gas with dry hydrated lime [calcium hydroxide, $Ca(OH)_2$] and recycled FGD product containing unreacted lime. Velocity is maintained to develop a fluidized bed in the columnar absorber. Water is injected into the scrubber in the throat of a venturi section at the bottom, cooling the gas at the inlet from 300°F or higher to approximately 160°F, depending on the relationship between approach to saturation and removal efficiency. The hydrated lime absorbs SO_2 from the gas and forms the reaction products calcium sulfite and calcium sulfate. A portion of hydrated lime reacts with CO_2 in the flue gas. The desulfurized flue gas flows out of the CFB, along with the reaction products, unreacted hydrated lime, calcium carbonate and the fly ash, to an ESP or baghouse.

Most CFB designs include equipment for on-site hydration of lime (calcium oxide, CaO), which reduces reagent cost compared with purchase of hydrated lime. Some developers claim improved performance with freshly prepared hydrated lime.

CFB differs from a spray-dryer in several ways. No moving parts or dual-fluid nozzles are required to mix lime with the flue gas. The CFB relies on dispersion of lime in a large mass of recycle solids from the particulate collector. When a large amount of recycle ash is used there is a reduced risk of wetting absorber walls compared with a typical spray-dryer due to the added drying surface provided by the recycle ash. This may allow a closer approach to saturation, which can improve SO_2 removal and lime utilization. SO_2 removal can be increased by increasing addition rate of dry hydrated lime without the lower temperature limit imposed on a spray-dryer absorber. However, lime utilization for the CFB generally decreases with increasing SO_2 removal.

A number of variations on the CFB-FGD technology are offered by various process developers .

SO_2 Removal Performance and Reagent Utilization

Wet FGD

Based on the coal compositions used in the wet FGD evaluations, liquid-to-gas ratios necessary to achieve 98% SO_2 removal were determined as shown in Table 2. The values for LSFO are based on demonstrations and testing by various FGD process developers and are further verified by recent guarantees offered by FGD vendors for new unit applications. For the Appalachian high- and low-sulfur coals, Sargent & Lundy estimated that L/G ratios of 130 and 80, respectively, will be required to achieve 98% SO_2 removal efficiency without the use of organic acid in a typical LSFO spray-tower absorber design. Limestone reagent utilization of at least 97% is required due to gypsum byproduct purity requirements.

Table 2. L/G to Achieve 98% Removal in Wet FGD vs. Coal Sulfur Content

Wet process	LSFO	LSFO	MEL	MEL
Coal type	Appalachian High Sulfur	Appalachian Low Sulfur	Appalachian High Sulfur	Appalachian Low Sulfur
L/G ratio, gpm per 1000 acfm at absorber outlet	130	80	40	30

Because of higher SO_2 absorption capacity available in the MEL system compared with the LSFO system, estimated L/G ratios of 40 and 30 are required to achieve 98% removal for the Appalachian high- and low-sulfur coals respectively. Lime utilization is near 100% due to high reactivity of lime and small particle size of slaked lime.

The difference in the L/G ratio requirements and the reagent between the LSFO and MEL processes has a major impact both on capital and O&M cost differences between the two competing technologies.

Dry FGD

Lime spray-dryer (LSD) and CFB based dry FGD systems have been demonstrated to economically achieve as high as 90-95% SO_2 removal efficiency. Dry FGD systems are applied mainly to low-sulfur coal, including PRB and western coals with inlet SO_2 less than 2.0 lb/Mbtu and low-sulfur eastern bituminous coal with inlet SO_2 concentrations as high as 3.0 lb/MBtu. However, the higher efficiency also typically results in lower lime utilization for both processes.

SO_2 removals chosen for the dry systems in this study are given in Table 3. SO_2 removals include removal that occurs in a subsequent ESP or baghouse. SO_2 removals for the spray-dryer-type absorber are based on likely outlet SO_2 emission limit guarantees available for the coal types used in the study. SO_2 removals for the CFB-type is higher but is assumed to be accompanied by lower lime utilization.

Some suppliers of FGD systems will utilize unreacted alkalinity in the ash collected in the particulate collector by recycling the ash back to the reactor. Of particular interest is the inherent alkalinity in Powder River Basin ash which has been exploited by systems designers and resulted in good reagent utilization compared to acidic fly ashes from eastern bituminous coal, resulting in a lower lime reagent ratio as shown in Table 3.

Table 3. SO_2 Removal and Lime Reagent Ratio vs. Coal Type for Dry FGD

Absorber type	**LSD**	**LSD**	**CFB**	**CFB**
Coal type	Appalachian Low sulfur	PRB Low sulfur	Appalachian Low sulfur	PRB Low sulfur
SO_2 removal, %	94	93	95	95
SO_2 emission, lb/Mbtu	0.12	0.10	0.10	.072
Reagent ratio, moles of Ca/mole of inlet SO_2	1.4	1.1	1.5 (retrofit) 1.35 (new)	1.2 (retrofit) 1.1 (new)

Commercial Status

Wet FGD

Wet FGD is a well-established technology with proven reliability operating in plants burning a variety of coals. Reagents used by the process are plentiful and readily available. The FGD system is not sensitive to boiler operational upsets and typical operating modes, such as cycling duty. However, due to the potential for acid pH in parts of the process and the presence of chlorine in the fuel, a high potential for corrosion is created in some of the system components which, in turn, require extensive use of costly corrosion-resistant alloys or nonmetallic liners as materials of construction. Alloy 317 LMN was used as a basis for this study and chloride level was limited to 8,000 ppm.

Both the LSFO and the MEL FGD systems are operating successfully at many coal-fired power facilities, ranging in size from less than 100 MW to 1000 MW. Many competing designs are available in the marketplace from a number of viable suppliers.

Large, single absorber modules have been demonstrated for application to a single unit up to 1000 MW.

Wet FGD systems also have the capability to efficiently remove oxidized forms of mercury from flue gas.

Dry FGD

Lime spray-dryer FGD systems are in operation at many facilities, ranging in size from less than 10 MW to 600 MW. However, currently the largest single absorber module is approximately

300 MW, so two absorbers were used in this study. Spray-dryer systems with rotary or dual fluid atomizers are available from a number of vendors.

CFB systems are in operation at many facilities ranging in size from less than 10 MW to 300 MW. A CFB unit, in Austria, is on a 275 MW size oil-fired boiler burning 1.0-2.0% sulfur oil. The CFB-based FGD system is commercially available from several vendors. Accordingly, for CFB application, two absorber modules were used for the 500 MW unit employed in this study.

Unlike wet FGD absorbers which must be constructed of expensive corrosion-resistant metals or other material, dry FGD absorbers can be constructed of less expensive carbon steel due to absence of a water-saturated gas. Because dry FGD systems operate without saturating the flue gas, they may not produce a visible moisture plume and, when used in conjunction with a fabric filter, are able to efficiently capture sulfur trioxide. Dry FGD systems are also capable of efficiently removing oxidized forms of mercury from flue gas.

By-Product Quality

Wet FGD

The by-product from either the wet LSFO process or the MEL process can be fashioned for use in the cement industry, for wallboard manufacturing, or for agricultural use. By-product quality requirements are much more stringent for wallboard manufacturing compared to the other uses.

While opportunities currently exist to contract to sell gypsum for a nominal $1-3 per ton, the future gypsum market holds many uncertainties and, therefore, it was assumed that the gypsum could be "sold" for $0 per ton in this study.

Dry FGD

The waste product contains $CaSO_3$, $CaSO_4$, $CaCO_3$, unreacted calcium hydroxide, and fly ash. Normally this material must be disposed in a landfill. There is potential for use as agricultural soil conditioning and for preparation of bricks or lightweight aggregates. If there is currently a significant market for fly ash, it may be prudent to install the dry FGD/baghouse combination after the fly ash particulate collector such that the fly ash is segregated from the LSD waste and can be "sold".

For disposal in a landfill, a disposal cost of $12 per dry ton was applied to the non-fly ash portion of the FGD byproduct.

Energy Consumption

Wet FGD

The process energy consumption results primarily from booster ID fan power required to overcome the draft loss across the absorber, power requirement for recirculation pumps, power required for oxidation air compressors, power for ball mills/slakers, power for gypsum dewatering system, and various electrical and control users typically needed for FGD operations. Table 4 shows L/G pumping requirements, absorber draft loss and the resultant overall energy consumption versus wet FGD process and coal type. These values were used in the evaluation to calculate power cost.

Table 4. L/G, Draft Loss and Power Consumption (% of MW_{net}) for Wet FGD vs. Coal Sulfur and Process

Process	**LSFO**	**LSFO**	**MEL**	**MEL**
Coal	Appalachian High Sulfur	Appalachian Low Sulfur	Appalachian High Sulfur	Appalachian Low Sulfur
L/G ratio, gpm per 1000 acfm at absorber outlet	130	80	40	30
Absorber draft loss, inches water	9	8	7	7
Power consumption, % of MW_{net}	2.0	1.3	1.4	1.0

The MEL process has a significant advantage over the LSFO process in power consumption. In the high-sulfur case, power requirement for slurry recirculation is 71% lower than for the LSFO process and the power requirement for the booster ID fan is 22% lower than for the LSFO process. Overall, the MEL process will require approximately 0.6% less auxiliary power for high-sulfur coal and approximately 0.3% less auxiliary power for low-sulfur coal compared to the LSFO process.

Dry FGD

A major component of the energy consumption in dry FGD is from draft loss across the absorber. In the study, the reactor draft loss for the LSD is 6-8 inches of water and for the CFB the loss is 8-10 inches. These values are used to compute parasitic power consumption, shown in Table 5. Power consumptions due to draft loss were not included in these values. These values were used in the evaluation to calculate power cost.

Table 5. Power Consumption for Dry FGD vs. Coal Sulfur and Process

Process	**LSD**	**LSD**	**CFB**	**CFB**
Coal type	Appalachian Low sulfur	PRB Low sulfur	Appalachian Low sulfur	PRB Low sulfur
Power consumption, % of MW_{net}:				
New Unit	0.65	0.70	0.80	0.90
Retrofit	1.1	1.2	0.80	0.90

New Units Versus Retrofit

Wet FGD

In new unit and retrofit applications, wet FGD technology is typically installed between the electrostatic precipitator/baghouse outlet and the stack. Retrofit units will usually have booster fans to overcome the pressure drop across the FGD absorber, which will be located after the existing ID fans. New units will be installed with ID fans large enough to overcome the pressure drop across the FGD absorber. This feature will result in lower capital cost for the draft system on a new unit application compared with a retrofit.

Retrofit units will usually not use existing stacks, as these stacks are designed for hot flue gas approximately at a 100 ft/sec exit velocity. To accommodate saturated flue gas from wet FGD, wet stacks are designed for a highly corrosion-resistant material with a gas velocity of between 55 to 70 ft/sec. Lower gas velocity is required to prevent condensed moisture from being carried out the top of the stack.

The capital cost estimates in this study for wet FGD retrofit includes cost for a new wet stack.

Dry FGD

A dry FGD system is installed between the air heater outlet and particulate collector. Most existing units have very short ductwork between the air heater outlet and electrostatic precipitator inlet. This makes it very difficult to take the gas from the air heater outlet to the dry FGD equipment and return it to the electrostatic precipitator inlet. Also, most existing electrostatic precipitators are not designed to handle increased particulate loading resulting from the dry FGD waste products. This will require modifications to the existing electrostatic precipitator to accommodate collection of the additional particulate from the dry FGD. In addition, an electrostatic precipitator will capture only a small percentage of the SO_2 (5% to 10%), placing a high burden on the dry FGD for SO_2 removal.

New units are expected to be installed with a baghouse rather than an ESP. Reagent utilization is expected to be better on units installed with a baghouse compared to retrofit units installed with modifications to an ESP. A baghouse can achieve 15% to 20% SO_2 capture lessening the burden on the dry FGD.

For both new units and retrofit with dry FGD and where fly ash sales are essential, a preferred arrangement may be to use an ESP for fly ash collection followed by a dry FGD or CFB and a baghouse for SO_2 collection.

In this study, for both new unit and retrofit, the spray-dryer is assumed be followed by a new pulse-jet baghouse. For retrofit of a CFB absorber, it is assumed that an existing ESP can be modified to follow it. Costs to modify the ESP to accommodate increased particulate loading are included in the capital cost. For a new unit application, the CFB is followed by a pulse-jet baghouse.

FGD DESIGN CRITERIA

The following additional design criteria were used in the evaluation. Table 6 shows flue gas flows and temperatures used for sizing absorber equipment for the various processes and coal types.

Table 6. Flue Gas Flows and Temperatures

FGD Processes	**LSFO, MEL**	**LSFO, MEL**	**LSD, CFB**	**LSD, CFB**
Heat input to boiler, MBtu/hr	5000	5000	5000	5186
Coal type	Appalachian High-sulfur	Appalachian Low-sulfur	Appalachian Low-sulfur	PRB Low-sulfur
Flue gas flow at FGD inlet*, macfm	1.75	1.70	1.79	1.97
Flue gas temperature at FGD inlet, °F	300	280	280	280
Flue gas flow at FGD outlet, macfm	1.52	1.50	1.60	1.75
Flue gas temperature at FGD outlet, °F	130	130	160	165

* includes air in-leakage, assumed same for new and retrofit

Table 7 shows additional design parameters for the wet FGD system designs. Lime and limestone costs are for reagent delivered to the power plant site by truck. For LSFO, a reagent ratio of 1.03 or less is required in order for gypsum byproduct to meet wallboard quality standards. Table 8 shows additional design parameters for the dry FGD systems.

Table 7. Additional Design Parameters Used for Wet FGD Comparison

	LSFO	**MEL**
SO_2 removal, %	98%	98%
By product	Gypsum	Gypsum
Reagent	Limestone	Lime
Reagent cost, $/ton	15	50
Reagent purity, %	95	94
Reagent ratio, moles of reagent/mole of sulfur removal	1.03	1.02
SO_2 oxidation stoichiometry (moles O fed/mole SO_2 removed)	3.0	3.0

Table 8. Additional Design Parameters Used for Dry FGD Comparison

Process	LSD	LSD	CFB	CFB
Coal type	Appalachian Low sulfur	PRB Low sulfur	Appalachian Low sulfur	PRB Low sulfur
SO_2 removal, %	94	93	95	95
Byproduct	Dry Waste	Dry Waste	Dry Waste	Dry Waste
Lime cost, $/ton	60	60	60	60
Reagent purity, %	93	93	93	93
Reagent ratio, moles of CaO/mole of inlet sulfur	1.4	1.1	1.5 (retrofit) 1.35 new)	1.2 (retrofit) 1.1 (new)

EVALUATION OF FGD COSTS

Capital Costs

The costs were developed primarily from Sargent & Lundy's cost database, which is continuously updated from ongoing work in the area of FGD.

The capital costs represent the "total plant cost," and include the following: equipment and material (FGD system and balance-of-plant); direct field labor; indirect field costs and engineering; contingency; owner's cost; allowance for funds during construction (AFUDC); and initial inventory and spare parts (1% of the process capital); and startup and commissioning. Owner's cost includes owner's project management, engineering, accounting, billing, etc., as well as an estimate for any "corporate" charges that may apply to capital projects. In many cases, owners will also place capital financing charges in this category. We have assumed in our analysis that the capital cost estimate is an "overnight" cost and therefore no financing charges or escalation are included. Contracting arrangement for implementation of an FGD project is assumed based on multiple lump sum specialty work packages. Relative accuracy of the capital costs is estimated at plus-or-minus 20%.

Table 9 presents results of capital cost estimates as total capital requirements for the wet FGD system for both new units and retrofit. Table 10 presents capital costs for the dry FGD systems for both new units and retrofit.

Table 9. Total Capital Requirements for 500 MW Wet FGD Systems: New Unit and Retrofit

Wet FGD process	**LSFO**		**MEL**	
Coal type	Appalachian High Sulfur	Appalachian Low Sulfur	Appalachian High Sulfur	Appalachian Low Sulfur
New unit:				
$	64,451,000	53,344,000	54,665,000	48,214,000
$/kW	125	107	109	96
Retrofit:				
$	85,958,000	76,106,000	76,256,000	69,659,000
$/kW	172	152	153	139

Table 10. Total Capital Requirements for 500 MW Dry FGD Systems: New Unit and Retrofit

Dry FGD process	**LSD**		**CFB**	
Coal type	Appalachian Low Sulfur	PRB Low Sulfur	Appalachian Low Sulfur	PRB Low Sulfur
New unit:				
$	61,291,000	62,581,000	66,914,000	68,551,000
$/kW	122	126	134	137
Retrofit:				
$	77,322,000	81,434,000	74,235,000	75,819,000
$/kW	155	163	149	152

Capital Cost Comparisons

The following comparisons can be made regarding capital costs for the LSFO, MEL and SDA technologies:

LSFO vs. MEL on High "S" Bit. Coal
Mel ~11% Lower (or $9.8 million)

LSFO vs. MEL on Low "S" Bit. Coal
Mel ~9% Lower (or $6.7 million)

MEL vs. SDA w/o baghouse on Low "S" Bit. Coal
Mel ~30% higher (or $16 million)

MEL vs. SDA w/baghouse on Low "S" Bit. Coal
MEL ~10% Lower (or $7.8 million)

SDA Comparison on Eastern and Western Low "S" Coal
~5% higher on Western sub. Bit. Coal (or $4.0 million)

Operations and Maintenance Costs

Tables 11, 12, 13, and 14 present results of determination of first-year O&M costs associated with the wet and dry FGD systems for new units and retrofit. Fixed operating costs include operating and maintenance labor, supervisory labor, and maintenance materials. Operating labor cost includes addition of 8 operators to the labor pool for a new unit and addition of 12 operators for a retrofit. Variable operating costs consist of mainly reagent, waste disposal or byproduct credit (gypsum is assumed "sold" for $0 per ton), and parasitic power. Power cost is assumed to be $30/MW-hr, which includes both energy and capacity charges. Variable operating costs were calculated assuming a 80% annual average load factor.

Table 11. First-Year Fixed and Variable Operating Costs for Wet FGD Processes and Coal Sulfur - New Unit

Wet FGD process	**LSFO ($/year)**		**MEL ($/year)**	
Coal type	Appalachian High Sulfur	Appalachian Low Sulfur	Appalachian High Sulfur	Appalachian Low Sulfur
Fixed Operating Costs	3,929,000	3,514,000	3,574,000	3,280,000
Variable Operating Costs:				
Reagent Costs	2,059,000	873,000	3,847,000	1,630,000
Waste Disposal Cost	0	0	0	0
Byproduct Credit	0	0	0	0
Water	208,000	208,000	208,000	208,000
Power	2,102,000	1,367,000	1,472,000	1,051,000
Total Variable Cost	4,369,000	2,448,000	5,527,000	2,889,000
Total O&M	8,298,000	5,962,000	9,101,000	6,169,000

Table 12. First-Year Fixed and Variable Operating Costs for Wet FGD Processes and Coal Sulfur - Retrofit

Wet FGD process	**LSFO ($/year)**		**MEL ($/year)**	
Coal type	Appalachian High Sulfur	Appalachian Low Sulfur	Appalachian High Sulfur	Appalachian Low Sulfur
Fixed Operating Costs	4,470,000	4,055,000	4,114,000	3,821,000
Variable Operating Costs:				
Reagent Costs	2,059,000	873,000	3,847,000	1,630,000
Waste Disposal Cost	0	0	0	0
Byproduct Credit	0	0	0	0
Water	208,000	208,000	208,000	208,000
Power	2,102,000	1,367,000	1,472,000	1,051,000
Total Variable Cost	4,369,000	2,448,000	5,527,000	2,889,000
Total O&M	8,839,000	6,503,000	9,641,000	6,710,000

Table 13. First-Year Fixed and Variable Operating Costs for Dry FGD Processes and Coal Sulfur - New Unit

Wet FGD process	**LSD ($/year)**		**CFB ($/year)**	
Coal type	Appalachian Low Sulfur	PRB Low Sulfur	Appalachian Low Sulfur	PRB Low Sulfur
Fixed Operating Costs	2,539,000	2,578,000	2,710,000	2,759,000
Variable Operating Costs:				
Reagent Costs	2,769,000	1,354,000	2,670,000	1,354,000
Waste Disposal Cost	1,071,000	589,000	1,057,000	596,000
Byproduct Credit	0	0	0	0
Bag Replacement	341,000	375,000	341,000	375,000
Cage Replacement	21,000	23,000	21,000	23,000
Water	102,000	127,000	102,000	127,000
Power	1,156,000	1,261,000	841,000	946,000
Total Variable Cost	5,460,000	3,729,000	5,032,000	3,421,000
Total O&M	7,999,000	6,307,000	7,742,000	6,180,000

Table 14. First-Year Fixed and Variable Operating Costs for Dry FGD Processes and Coal Sulfur - Retrofit

Wet FGD process	**LSD ($/year)**		**CFB ($/year)**	
Coal type	Appalachian Low Sulfur	PRB Low Sulfur	Appalachian Low Sulfur	PRB Low Sulfur
Fixed Operating Costs	2,944,000	2,983,000	2,710,000	2,759,000
Variable Operating Costs:				
Reagent Costs	2,769,000	1,354,000	2,967,000	1,477,000
Waste Disposal Cost	1,071,000	589,000	1,116,000	621,000
Byproduct Credit	0	0	0	0
Bag Replacement	341,000	375,000	341,000	375,000
Cage Replacement	21,000	23,000	21,000	23,000
Water	102,000	127,000	102,000	127,000
Power	1,156,000	1,261,000	841,000	946,000
Total Variable Cost	5,460,000	3,729,000	5,026,000	3,171,000
Total O&M	8,404,000	6,712,000	8,141,000	6,336,000

Table 14 shows calculated parasitic power consumption for the wet FGD processes as a function of coal sulfur content. Power consumption is lower for the MEL system due to lower recycle pump flow and lower spray header elevation and lower absorber draft loss, all due to lower L/G.

O&M Cost Comparisons

The following comparisons can be made regarding O&M costs for the LSFO, MEL, and SDA technologies:

- LSFO vs. Mel on High "S" Bit. Coal
  - MEL ~9% Higher (or $0.98 million/year)
- LSFO vs. MEL on Low "S" Bit. Coal
  - MEL ~3.3% Higher (or $0.26 million/year)
- MEL vs. SDA w/o Baghouse on Low "S" Bit. Coal
  - MEL ~10% Higher (or $0.61 million/year)
- MEL vs. SDA w/Baghouse on Low "S" Bit. Coal
  - MEL is equivalent
- SDA Comparison on Eastern and Western Low "S" Coal
  - SDA ~25% lower on Western Sub. Bitu. Coal

Levelized Costs

Levelized costs, also referred to as "life cycle costs," take into account impacts of capital costs and O&M cost during the operation of a plant over the period of analysis. Table 15 includes factors used in this study to levelize capital and operating costs. The levelized fixed charge rate (impact due to capital cost) was calculated based on an assumption that a typical customer is a regulated utility. The levelized fixed charge rate includes depreciation of the property, return on capital (50% debt and 50% equity), income tax, property tax, and insurance. Based on an 8.75% discount rate and 30-year or 20-year life expectancy for new or retrofit facilities, respectively, the levelized fixed charge rates are 14.50% (30-year life) and 15.43% (20-years life). The levelized cost analysis was performed based on current dollars, as most regulated utilities base their analysis on current dollars.

The levelized O&M cost factor takes into account plant life, discount rate, and inflation rate. The levelized O&M cost factors were 1.30 for the 30-year period and 1.22 for the 20-year analysis.

Table 15. Capital and Operating Cost Levelizing Factors for New Unit and Retrofit

	New Unit	**Retrofit**
Plant Life, years	30	20
Capital cost levelizing factor, %/year	14.5	15.43
Discount rate, %	8.75	8.75
Inflation rate, %	2.5	2.5
Operating cost levelization factor	1.30	1.22

Tables 16 through 19 shows levelized costs for wet and dry FGD.

Table 16. Levelized Costs for Wet FGD for New Unit

Process	**LSFO**		**MEL**	
Coal type	Appalachian High sulfur	Appalachian Low sulfur	Appalachian High sulfur	Appalachian Low sulfur
Total capital cost $MM	62.5	53.3	54.7	48.2
Levelized capital Cost, MM$/yr	9.06	7.73	7.93	6.99
Levelized O&M Cost, MM$/yr	10.79	7.75	11.83	8.02
Total Levelized Cost, MM$/yr	19.84	15.49	19.76	15.01
Total cents/kW-hr	0.57	0.44	0.57	0.43

Table 17. Levelized Costs for Wet FGD for Retrofit

Process	**LSFO**		**MEL**	
Coal type	Appalachian High sulfur	Appalachian Low sulfur	Appalachian High sulfur	Appalachian Low sulfur
Total capital cost $MM	86.0	76.1	76.3	69.7
Levelized capital Cost, MM$/yr	13.26	11.74	11.77	10.75
Levelized O&M Cost, MM$/yr	10.78	7.93	11.76	8.19
Total Levelized Cost, MM$/yr	24.05	19.68	23.53	18.93
Total cents/kW-hr	0.69	0.56	0.67	0.54

Table 18. Levelized Operating Cost for Dry FGD for New Unit

Process	**LSD**		**CFB**	
Coal type	PRB Low sulfur	Appalachian Low sulfur	PRB Low sulfur	Appalachian Low sulfur
Total capital cost $MM	62.6	61.3	68.6	66.9
Levelized capital Cost, MM$/yr	9.07	8.89	9.07	8.89
Levelized O&M Cost, MM$/yr	8.20	10.40	8.03	10.06
Total Levelized Cost, MM$/yr	17.27	19.29	17.52	19.36
Total cents/kW-hr	0.49	0.55	.49	.54

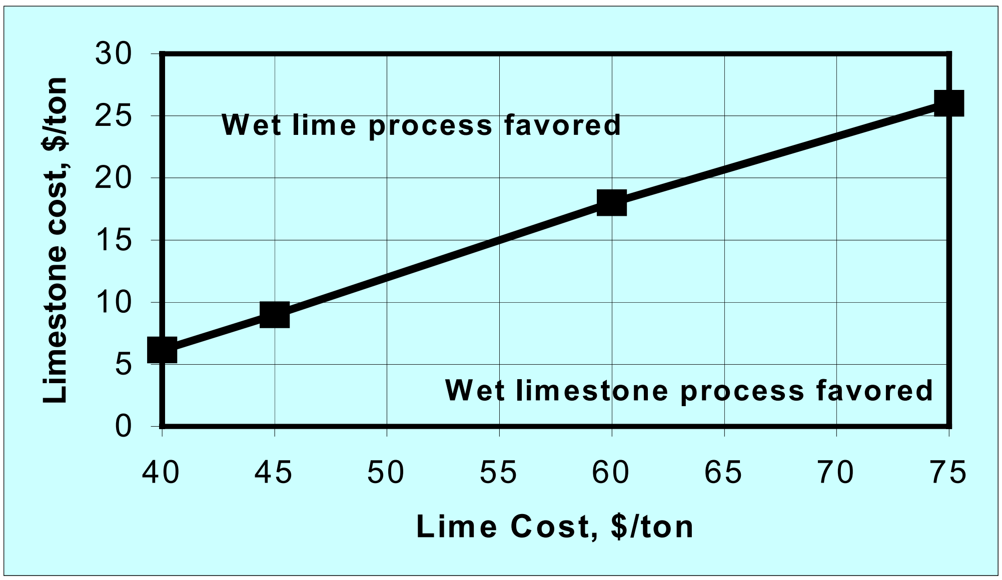
Table 19. Levelized Operating Cost for Dry FGD for Retrofit

Process	**LSD**		**CFB**	
Coal type	PRB Low sulfur	Appalachian Low sulfur	PRB Low sulfur	Appalachian Low sulfur
Total capital cost $MM	81.4	77.3	75.6	74.1
Levelized capital Cost, MM$/yr	12.57	11.93	12.57	11.93
Levelized O&M Cost, MM$/yr	8.19	10.25	7.73	9.93
Total Levelized Cost, MM$/yr	20.75	22.18	20.30	21.86
Total cents/kW-hr	0.59	0.63	.58	0.62

Life Cycle Comparisons

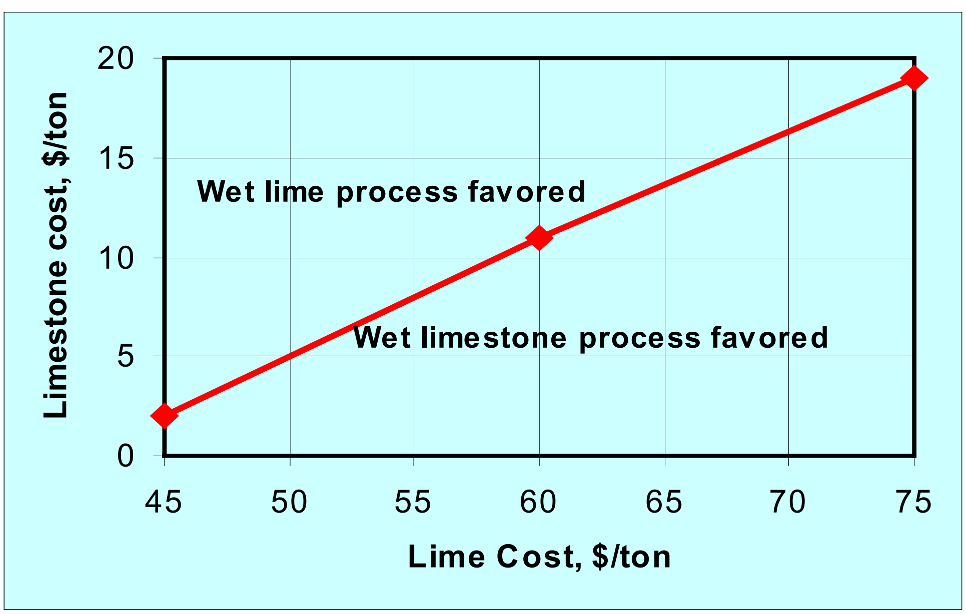
Considering only the wet FGD technologies (LSFO and MEL), the following life cycle comparisons were made to quantify the relative economics of using limestone or lime as the FGD reagent.

1. Reagent Cost Sensitivity (High "S"):



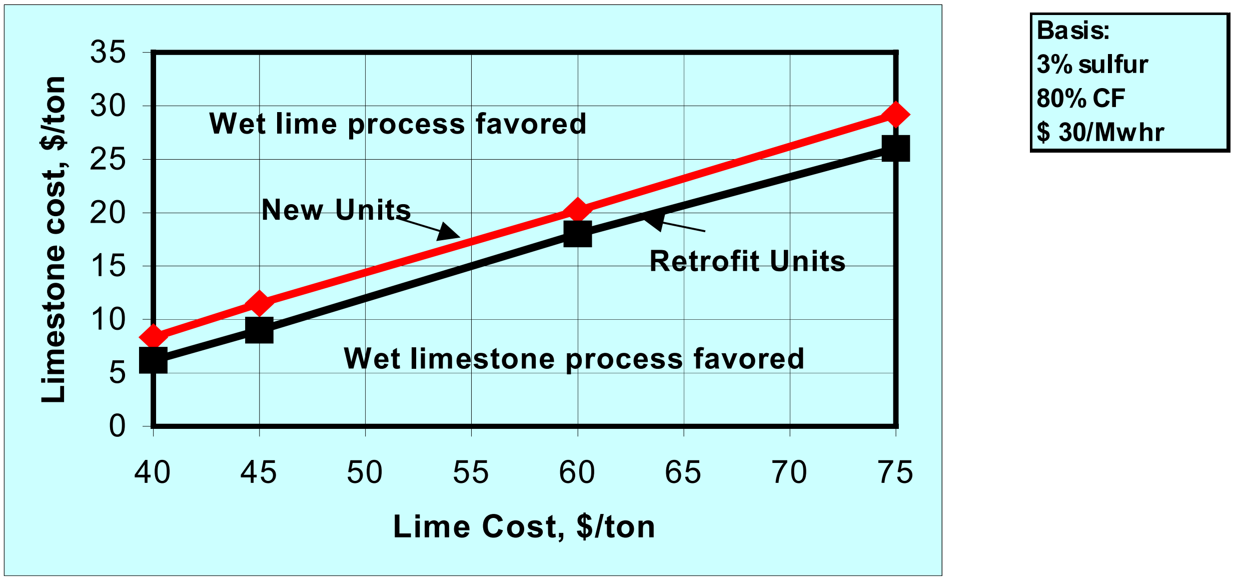
Basis:
3% sulfur
Retrofit
80% CF
$ 30/Mwhr

Reagent Cost Sensitivity (Low "S")



Basis:
1.3% sulfur
Retrofit
80% CF
$ 30/Mwhr

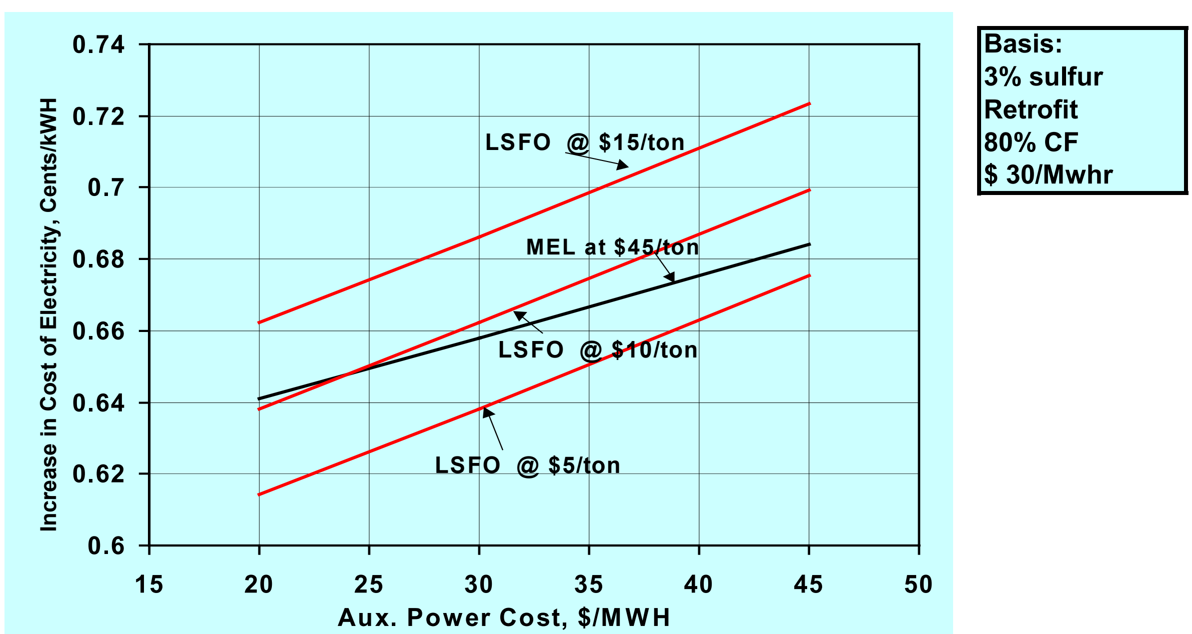
2. New Unit Vs. Retrofit Unit



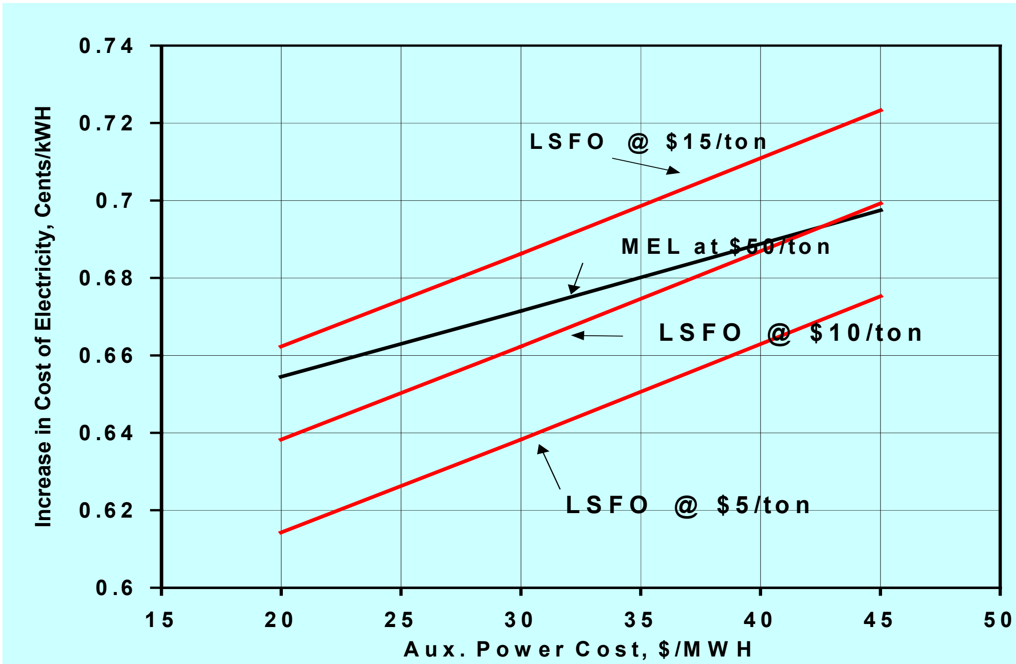
3. Auxiliary Power Cost

Using high sulfur coal, the following three graphs show the affect that auxiliary power costs have on the choice of reagent (limestone vs. lime) for three different limestone costs and three different lime costs:

Aux. Power Sensitivity (Lime @ $45/ton)

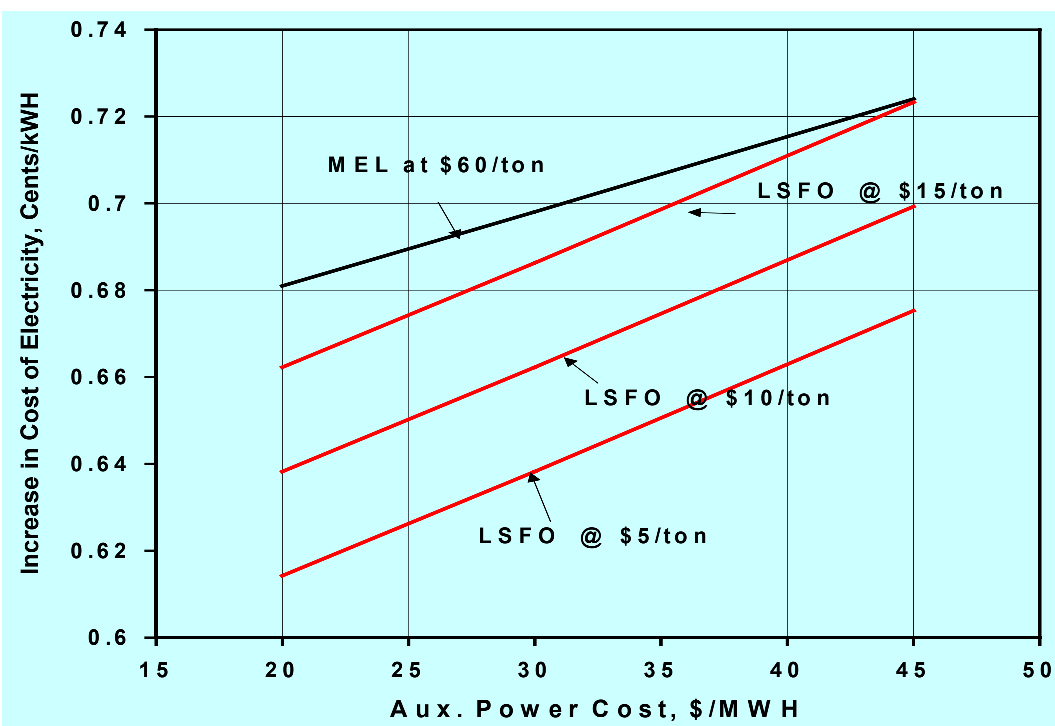


Aux. Power Sensitivity (Lime @ $50/ton)



Basis:
3% sulfur
Retrofit
80% CF
$ 30/Mwhr

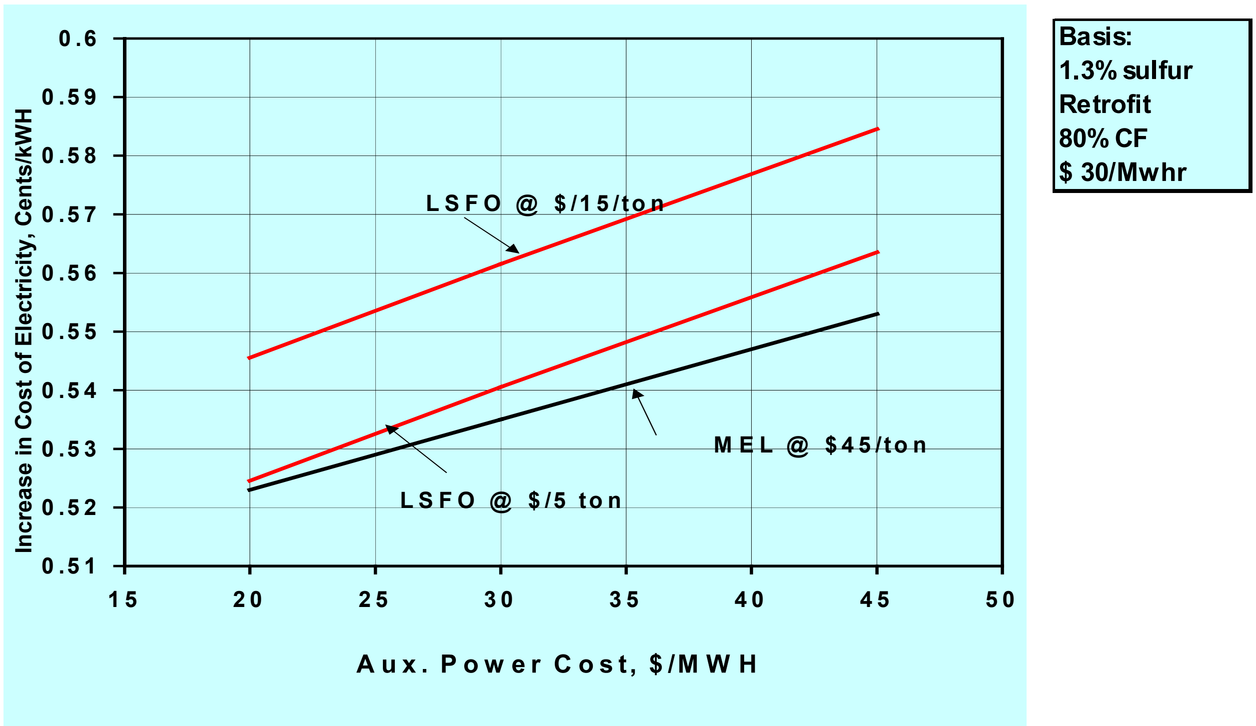
Aux. Power Sensitivity (Lime @ $60/ton)



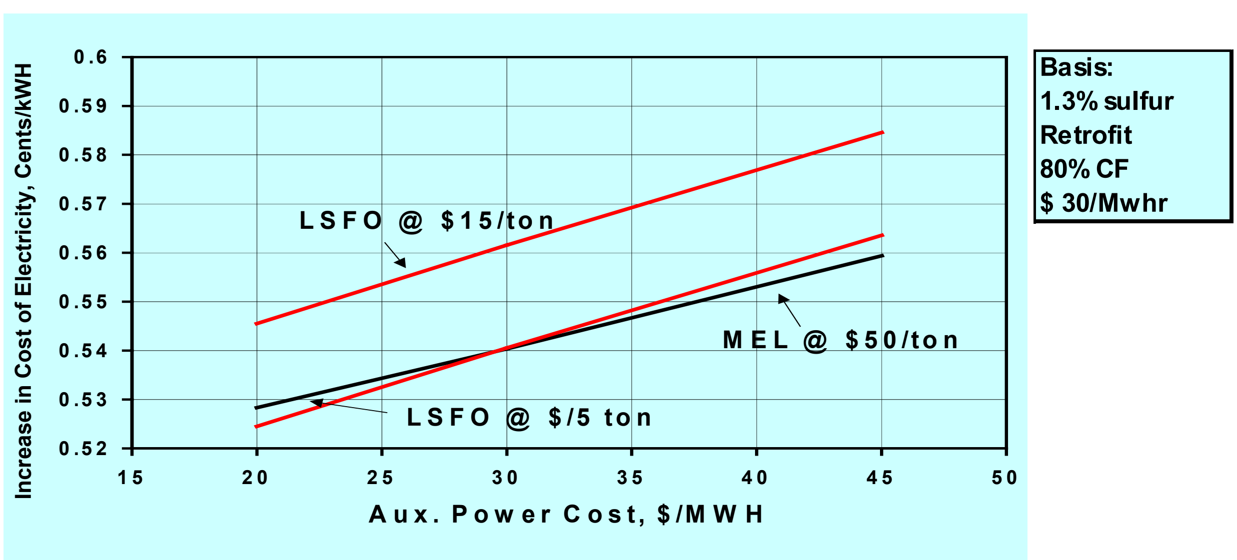
Basis:
3% sulfur
Retrofit
80% CF
$ 30/Mwhr

Similarly, for low sulfur coal applications the following graphs represent the affect of auxiliary power costs on reagent choice:

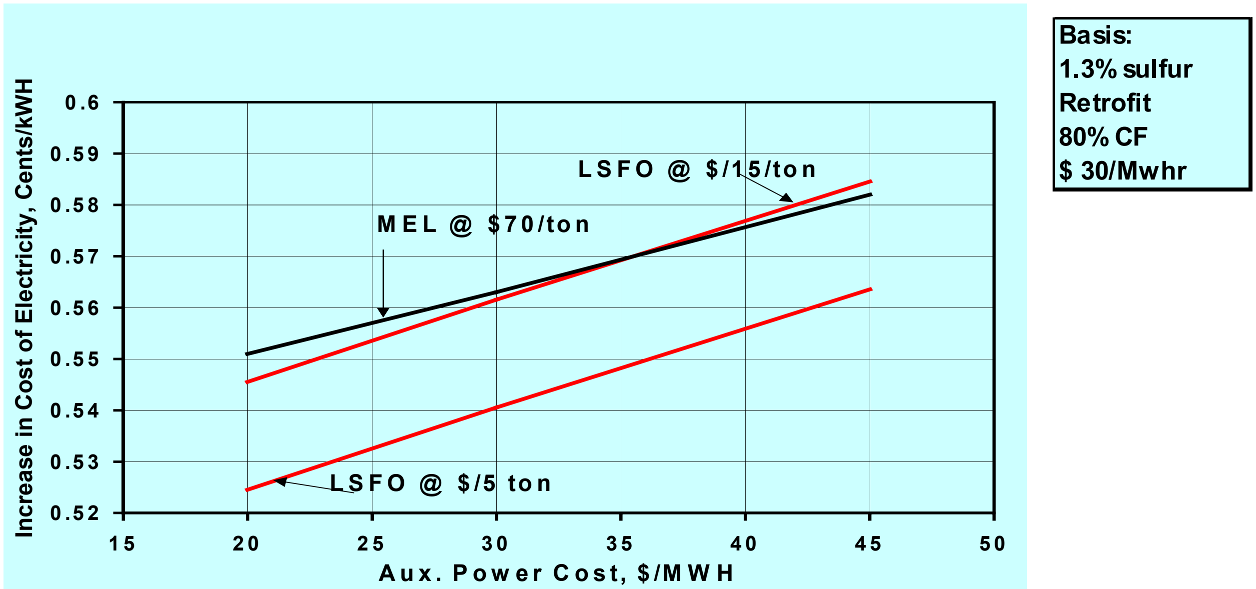
Aux. Power Sensitivity (Low "S", Lime @ $45/ton)



Aux. Power Sensitivity (Low "S", Lime @ $50/ton)



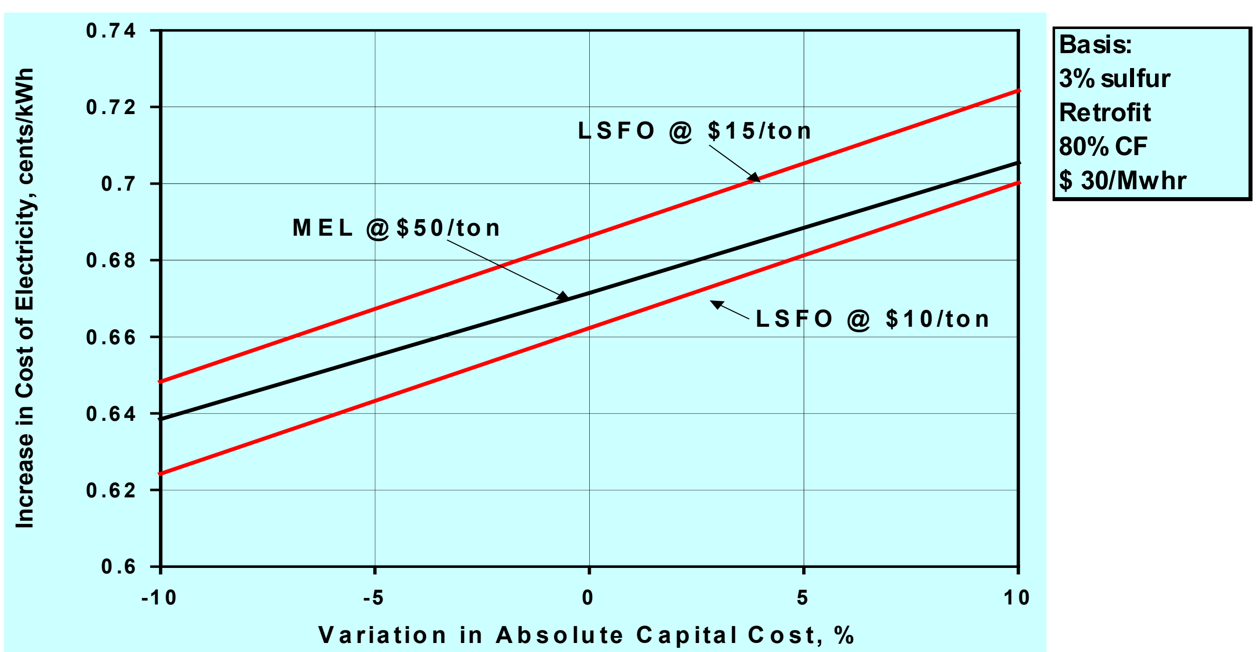
Aux. Power Sensitivity (Low "S", Lime @ $70/ton)



4. Capital Cost

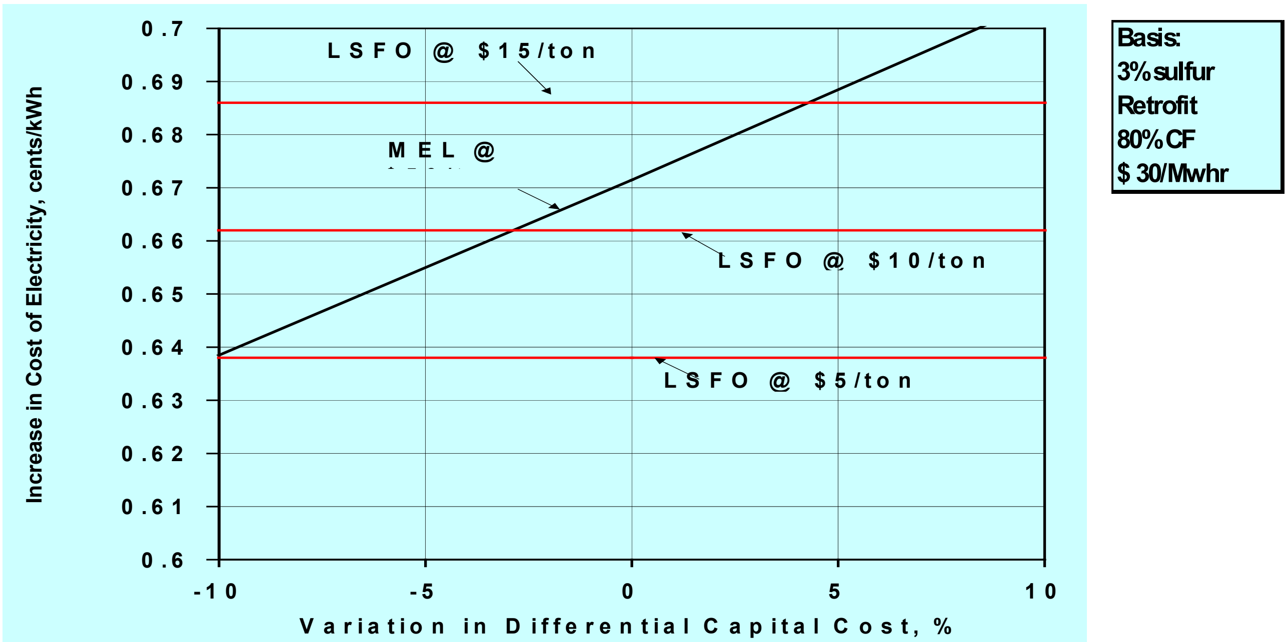
The following graph shows an example of the sensitivity of reagent choice to the accuracy in the capital cost estimate for each of technologies:

High "S" Appalachian Coal – Capital Cost Sensitivity



Similarly, the following graph shows an example of the sensitivity of reagent choice to the size of the difference between the capital costs for the LSFO technology vs. the MEL technology.

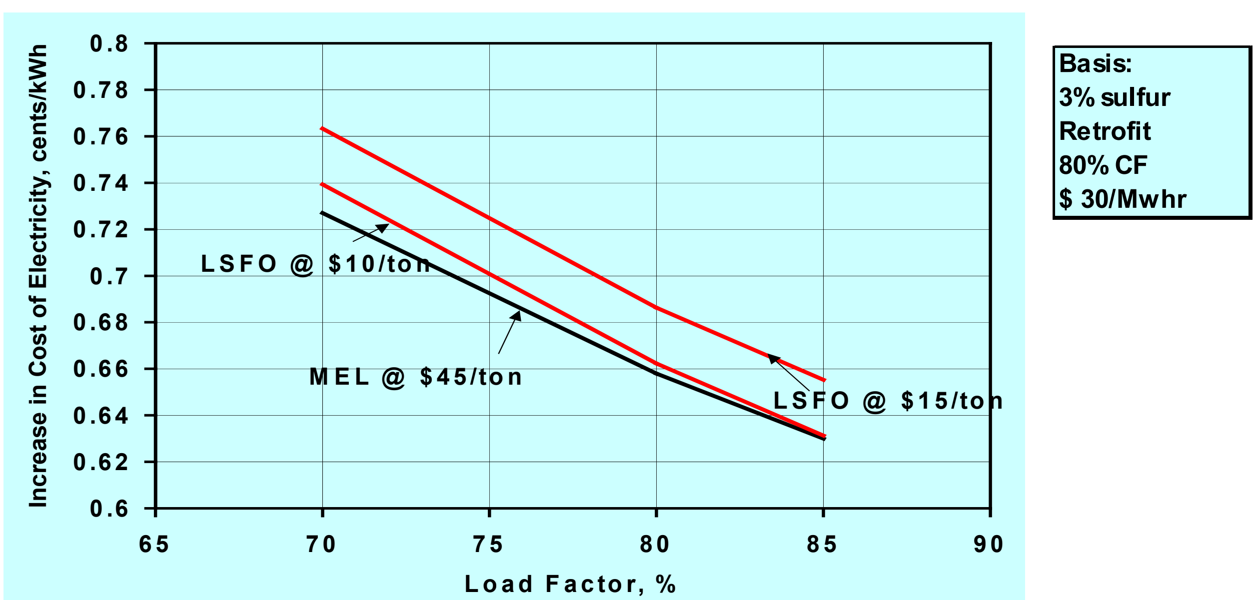
High "S" Appalachian Coal – Capital Cost Sensitivity (Assume Constant LSFO Cost)



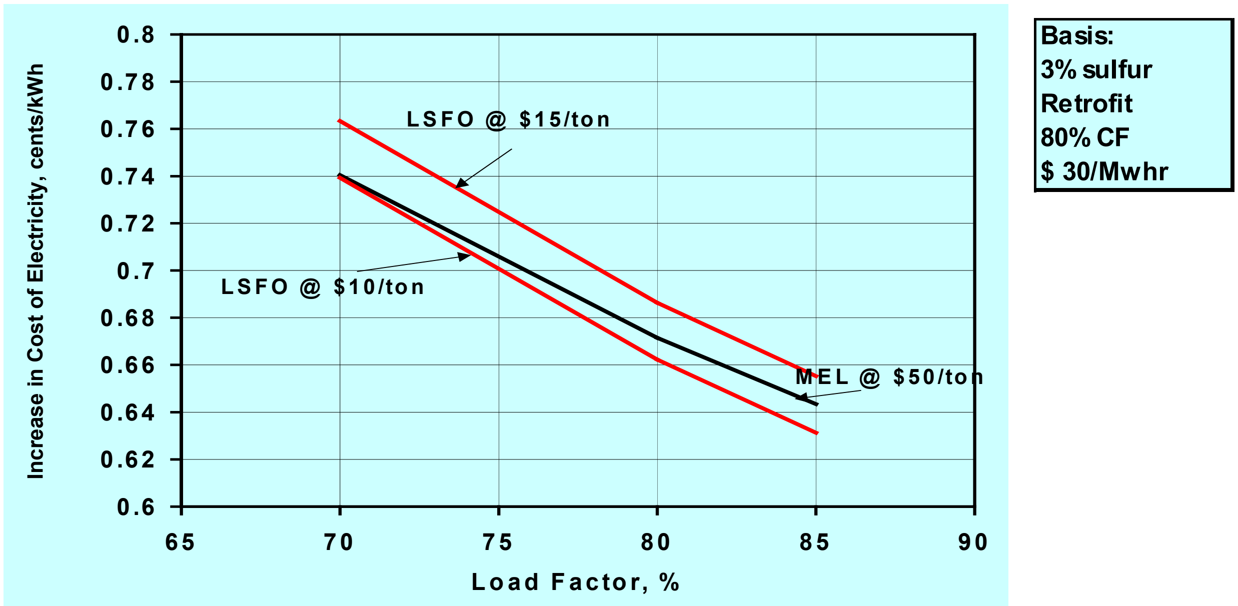
4. Plant Capacity Factor

The following three graphs show the affect that the plant capacity factor has on reagent choice for a high sulfur application for various reagent costs.

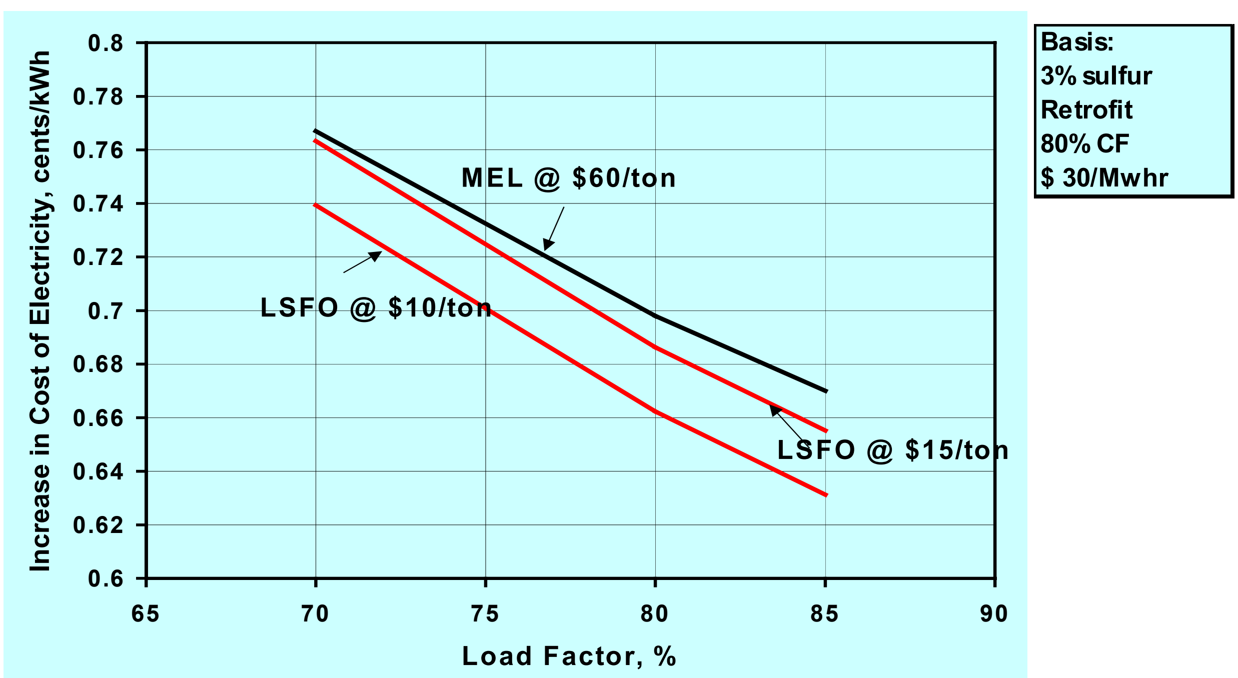
High "S" Appalachian Coal – Load Factor Sensitivity (Lime @ $45/ton)



High "S" Appalachian Coal – Load Factor Sensitivity (Lime @ $50/ton)



High "S" Appalachian Coal – Load Factor Sensitivity (Lime @ $60/ton)



Conclusions

1. Lime's position as a candidate FGD reagent improves as the sulfur content of the fuel decreases.

2. Because of a generally higher capital cost for retrofit applications versus new unit applications, Lime's position will be marginally better in retrofit applications of FGD technology.

3. Because the "cost" of auxiliary power on new units is generally higher than on existing units, the relative competitive position of lime will look better when the MEL process is applied on new units. This phenomenon becomes less important as the fuel sulfur content is reduced.

4. The absolute value of the capital cost is not nearly as important as the differential cost between LSFO and MEL technologies.