SO_2 Control Update to PPL Montana's J.E. Corette Generating Station BART Report

Prepared for

PPL Montana, LLC

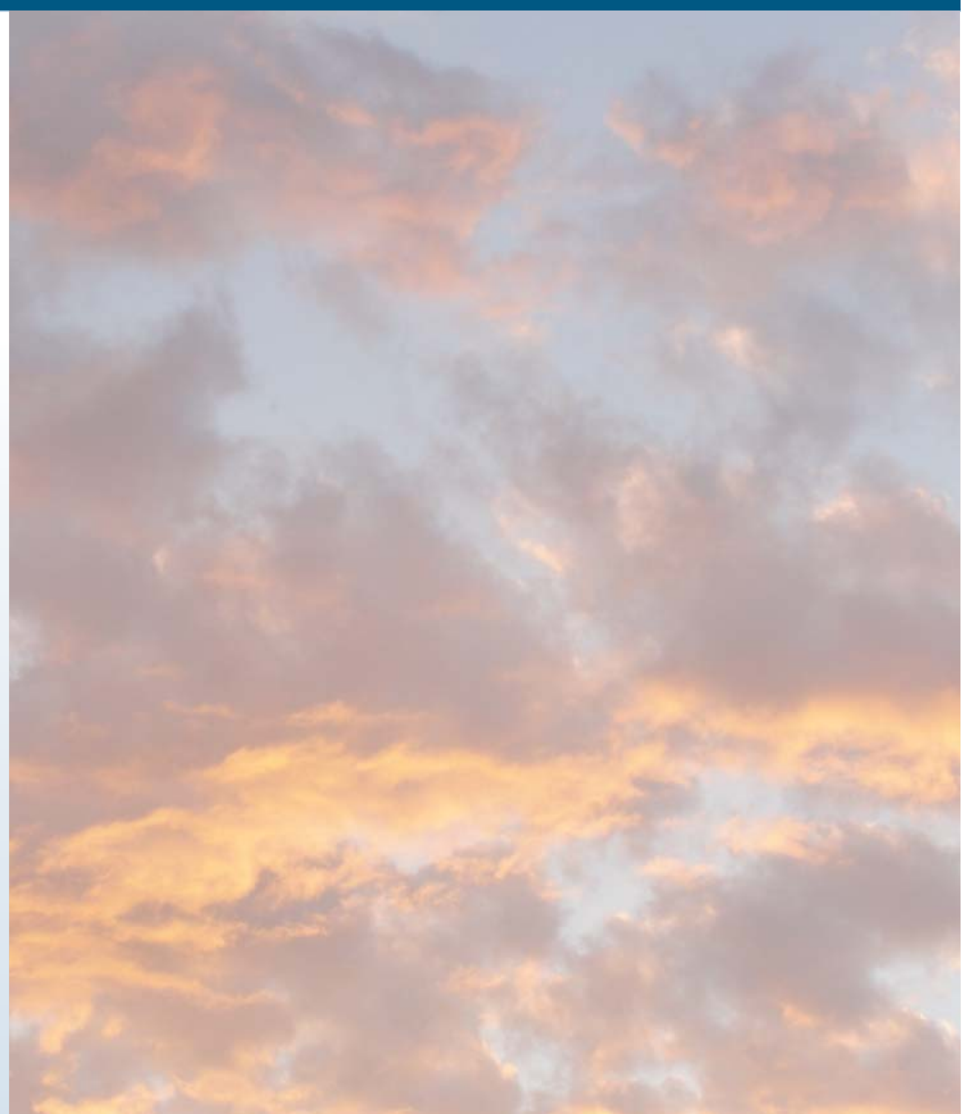
Billings, Montana

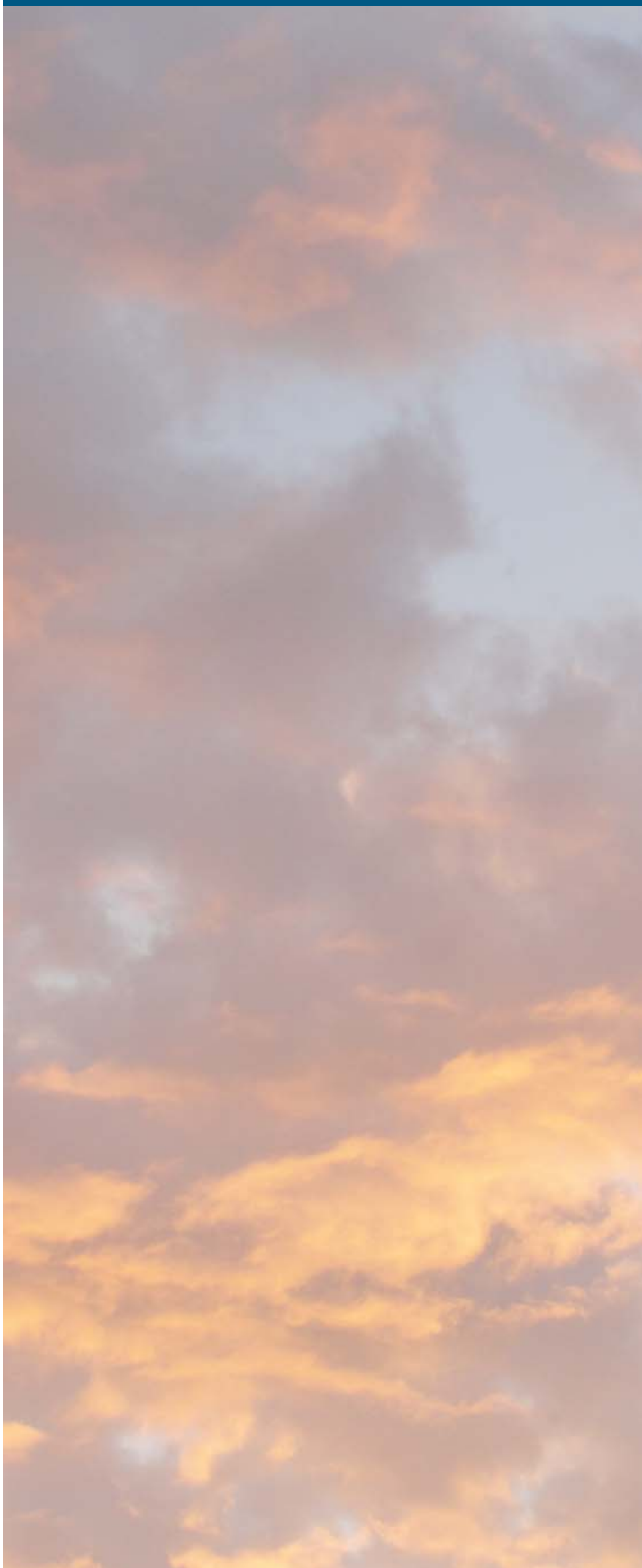
Prepared by

TRC

Windsor, Connecticut

August 2011





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TRC Project No. 184990

August 2011

EXECUTIVE SUMMARY

As part of the Best Available Retrofit Technology (BART) assessment for the J.E. Corette (Corette) coal-fired steam electric plant, an economic cost effectiveness analysis was performed in an initial report dated August 2007. Upon review and comment by the U.S. Environmental Protection Agency Region 8, the initial analysis was updated in an addendum report dated June 2008. On May 18, 2011, EPA requested a further update on costs of SO_2 controls for Corette. This Addendum to the initial reports provides an updated assessment to address SO_2 control costs.

The Corette power plant, located in Billings, Montana, is owned and operated by PPL Montana, LLC. The coal-fired boiler at the plant was determined to be BART-eligible under the Federal Regional Haze Rule by the U.S. Environmental Protection Agency Region 8. It is a 162 MW electrical generation unit that burns low sulfur sub-bituminous coal.

Since these reports were prepared, new cost analysis techniques have been developed as part of the Integrated Planning Model (the IPM) under a grant from the U.S. EPA, "Documentation for EPA Base Case v.4.10 Using the Integrated Planning Model". See the following link for more details:

http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html#documentation)

ICF International (ICF) developed the IPM to assess the combined effect that air rules have on the utility industry as a whole. This platform has also been used by EPA's Clean Air Markets Division for analyzing recent air policy decisions. Based upon currently available information, the control technology cost estimation techniques developed for the IPM appear to be more robust than those used in the previous BART reports prepared by PPL Montana. TRC has used these IPM analytical techniques for updating the 2007 and 2008 cost effectiveness analyses for dry injection, spray dryer absorption, and wet flue gas desulfurization control technologies. These costs reflect our best high level estimate based on the data currently available. They include cost updating to reflect significant increases in material and labor costs.

Consistent with the June 2008 Addendum, TRC estimated costs for the control technologies evaluated based on typical emission rates representative of a 30-day average and the maximum 24-hour emission rates based on data during the modeling years (2001, 2002 & 2003) as requested by EPA. Even though PPL Montana believes that the actual cost effectiveness should be based on a longer time basis utilizing typical emission rates (30-day average at a minimum) and that a shorter time basis and maximum emission rates are not representative of site-specific cost effectiveness, we are providing the 24-hour cost calculation as requested. The 30-day running average SO_2 emission rate is 0.46 lbs SO_2/MMBtu and the 24-hour emission rate is 0.60 lbs SO_2/MMBtu.

For this updated assessment, we have evaluated three technologies for cost effectiveness in reducing sulfur dioxide (SO_2) emissions. The results are discussed below. The details of the cost effectiveness calculations for each control technology are provided in Section 4 and the associated tables.

Regarding the wet Flue Gas Desulfurization (FGD) option, the Corette air permit requires that plume buoyancy be maintained and a wet scrubber would decrease plume buoyancy significantly. Consequently, a significant amount of reheat would need to be applied in order to meet stipulated SO_2 and plume buoyancy requirements. In addition to the high cost for FGD, there are significant site constraints that effectively eliminate this technology from any further evaluation. For completeness, control costs for this option are presented in Section 4 of this report.

The two reagent injection technologies, "Dry Sorbent Injection" (DSI), and "Spray Dryer Absorption" (SDA) involve the injection of quantities of dry chemicals into the exhaust for the absorption of SO_2. These injected reagents, plus the sulfates formed from the SO_2 absorption, will result in increased particulate loading to and emissions from the control device which is currently an electrostatic precipitator. Controlling the additional particulate will likely require particulate control equipment upgrades. SDA will also likely require plume reheat, which has been included. This is because in a SDA system, a water slurry containing lime is sprayed into the gas stream that will reduce plume temperature and plume reheat will be required to maintain plume buoyancy. The cost of all these upgrades is included in the cost effectiveness calculations significantly increasing the cost to apply these technologies at Corette.

The dry sorbent injection - DSI system is estimated to reduce SO_2 emissions to about 0.26 lbs SO_2/MMBtu with a cost effectiveness of approximately $10,920 per ton of SO_2 removed on an annualized basis. The spray dryer absorption - SDA system is estimated to reduce emissions to about 0.13 lbs SO_2/MMBtu with a cost effectiveness of approximately $18,839 per ton of SO_2 removed on an annualized basis. For this report, PPL Montana determined that it is was not necessary to update any of the June 2008 visibility assessments as the range of SO_2 emission reductions achieved by the evaluated control technologies in this addendum is within the range of SO_2 reductions previously evaluated. The additional analyses provided by this addendum do not change the conclusion that PPL Montana reached for the Corette boiler in its August 2007 BART Assessment or the June 2008 Addendum that implementation of further SO_2 controls is not warranted.

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ATTACHMENTS

1.0 BACKGROUND

In August 2007, TRC prepared a BART analysis for PPL Montana, LLC that contained cost analyses for potential control of SO_2 emissions at Corette. Dry reagent injection (dry injection), dry gas scrubbing (spray dryer absorption), and wet scrubbing (wet FDG) were included in the August 2007 assessment report as available and applicable control technologies. Cost information available at that time was limited to data developed by Srivastava in 2001 for wet and spray dryer control techniques, however, the data were only available in terms of broad ranges of capital equipment and annual operating and maintenance costs. TRC used this source of information in determining the cost effectiveness as contained in the US EPA Air Pollution Control Technology Fact Sheet, EPA-452/F-03-034.

On February 4, 2008, EPA commented on the August 2007 submittal for Corette. Although TRC based the economic analysis on EPA data for SO_2 control, EPA requested revisions to the capital cost amortization from 11 to 15 years, and analysis of higher SO_2 control efficiencies. No additional references for developing the cost of SO_2 control equipment were identified in the EPA letter or in the TRC response to the EPA request. EPA suggested that the 2002 Air Pollution Control Cost Manual (the CCM) be used to revise the cost estimations, however, TRC pointed out in the June 2008 addendum to the August 2007 BART assessment submittal, that the CCM provides cost estimation techniques for small industrial sized scrubbers with maximum exhaust gas flows up to about 200,000 actual cubic feet per minute (acfm) and therefore, no better data for cost estimation existed at that time.

On May 18, 2011, EPA requested a further update on costs of SO_2 controls for Corette. The results of the cost development for the IPM study shows that costs have increased for the installation of retrofit control equipment and the more robust analytical techniques for dry injection, spray dryer absorption and wet flue gas desulfurization have herein been applied to update the 2007 and 2008 cost estimations.

2.0 RECENT DEVELOPMENTS

When the final rule was promulgated in 2005 (see FR Vol. 70, No. 128, July 6, 2005), much of the then available Air Pollution Control Equipment (APCE) cost data were contained in the CCM published in January 2002. For SO_2, the gas absorber costing techniques were limited to industrial applications with up to approximately 200,000 acfm of exhaust flow. Utility applications of flue gas desulfurization (FGD) using wet scrubbing were installed and operating on utility boilers in the USA, however, no compilation of the cost of such utility sized systems was available.

Using costing tools available at that time, analyses of BART were submitted to regional offices of EPA as required and reviews of the reports, such as those submitted by PPL Montana, were performed. Simultaneously, however, EPA was utilizing available planning tools to study the universe of environmental effects that rules such as the Clean Air Interstate Rule (CAIR), Best Available Retrofit Technology (BART), and other local rules would have on the utility industry in the USA. One such tool used by EPA is the Integrated Planning Model or the IPM.

In the description of the development of the IPM, examples of the costing approach are included for model utility boiler plants. As shown in the illustrative example, costs for spray dryer absorbers, both capital and operating and maintenance costs, are a strong function of unit capacity. Figures 2.0-1 and 2.0-2 show a general trend line for the application of the cost analysis techniques to coal-fired plants of 5 values of gross power output from 100 to 1,000 megawatts (MW). Figure 2.0-1 is the total capital cost for equipment and installation and Figure 2.0-2 shows the operation and maintenance costs in $/KW.

These figures are presented to illustrate the general tendency of the cost analysis to return higher capital and operation and maintenance costs for small capacity plants. Appendices to the EPA summary document contain the detailed equations used in the cost analysis developed to support the IPM. Copies of these reports are included in Attachment A.

2.1 The IPM Approach to the Costing of Air Pollution Controls

ICF International (ICF) developed a proprietary tool known as the IPM to assess the combined effect that air rules have on the utility industry as a whole. This platform has also been used by EPA's Clean Air Markets Division for analyzing air policy decisions. One aspect of the IPM is the capital, operating, and maintenance cost of air pollution control equipment. These costing analytical techniques were summarized in reference 1, available from the US EPA Clean Air Markets Division or through the link provided in the executive summary of this report. For SO_2, APCE cost analyses for two control technologies are presented; lime spray dryer absorption (SDA), and wet flue gas desulfurization (wet FGD).

Figure 2.0-1 Illustrative Dry Scrubber Capital Costs

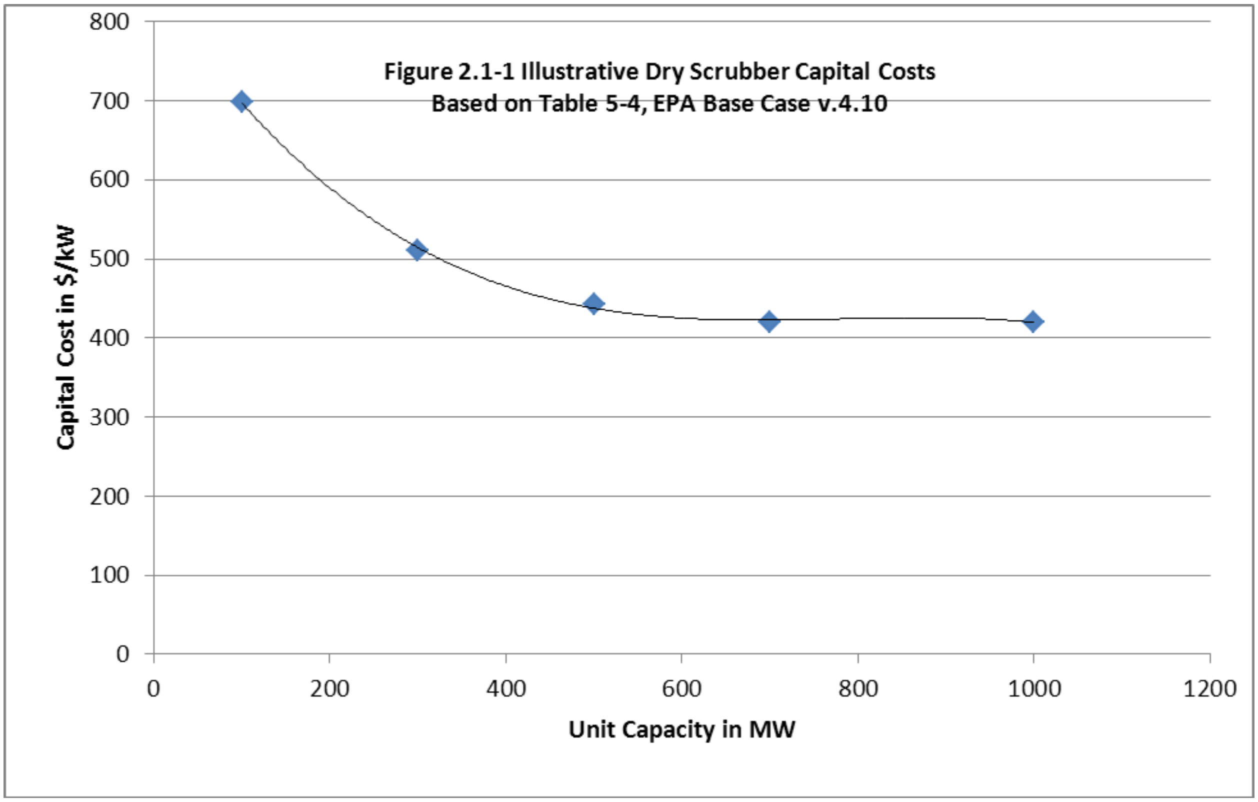
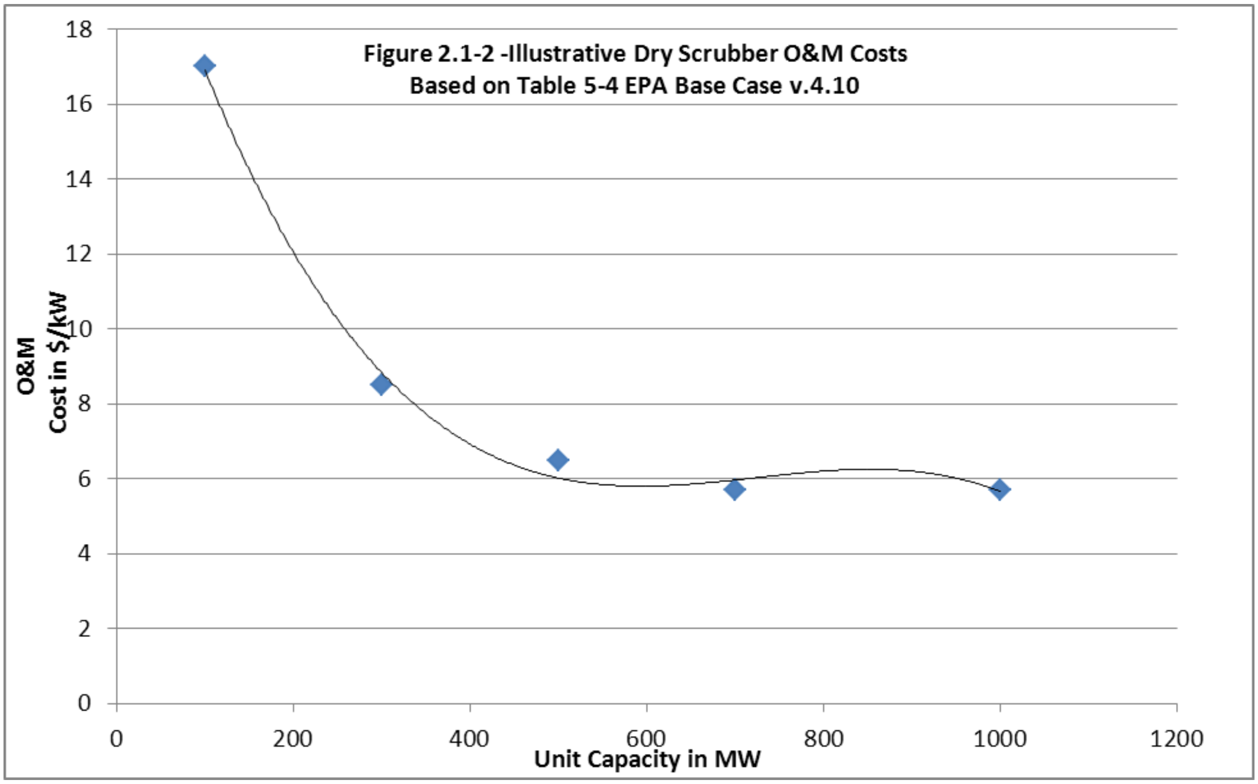


Figure 2.0-2 Illustrative Dry Scrubber O&M Costs



Greater detail regarding the IPM is included in three appendices to this document. Each appendix includes the analytical equations used by the engineering firm Sargent & Lundy (S&L) in their background studies upon which EPA based their control cost analyses. These appendices allow users to calculate cost estimations for plant specific data. Therefore, using the S&L equations, cost estimations were compiled for the Corette boiler.

2.2 Dry Sorbent Injection, Spray Dryer Absorbers, and Wet Flue Gas Desulfurization

In dry sorbent injection, dry chemical sorbent is injected into the flue gas downstream of the boiler and prior to the particulate control device. The chemical reagent reacts with SO_2 and forms sulfates which are partially removed in the particulate controls. The technique increases loading to the particulate control equipment and creates additional ash.

In a spray dryer absorber (SDA), a slurry of slaked lime is sprayed into the gas stream where the lime reacts with SO_2 to form solid sulfates. Unreacted lime and sulfate solids together with coal fly ash are then collected in the particulate APCD. System performance is limited by the capacity and type of particulate control equipment which is either an electrostatic precipitator or a fabric filter baghouse. In the SDA technique, adequate water is added to the lime to allow it to be sprayed into the hot exhaust, but the amount of water is limited to that which will totally evaporate into the gas stream. In a wet FGD system, a solution of limestone in water is intimately placed in contact with the SO_2 laden exhaust and reactions occur in the liquid phase as opposed to the gas. Wet FGD systems are typically located after the particulate APCE.

Corette at 162 MW in gross power output is in the range of the applicability of the calculation techniques which apply to utility boilers greater than 25 MW in gross power output. The three S&L appendices are included as Attachment A to this report in which the capital cost model breaks the costing analysis into several parts that sum to provide the total capital and engineering cost of an installation. These include the absorber island, the reagent preparation equipment, waste handling equipment, and the balance of the plant that includes ducting, fans, instrumentation, etc.

2.3 Other Technologies

PPL Montana investigated the NeuStream-S wet scrubber that the Colorado Martin Drake #7 plant that is planning to implement for SO_2 control in 2012. This technology is not commercially available at this time and any performance/costs estimates that are published are specifically related to a pilot study conducted at Martin Drake #7. Full scale, commercial numbers on performance and cost will not be available until after 2012.

3.0 APPENDICES TO THE IPM COST APPROACH

The IPM costing approach to SO_2 control includes more detailed analytical tools for cost determinations than is provided in the summary document. The three appendices provided as Attachments B to this revised costing study apply to 1) Dry Sorbent Injection, 2) Spray Dryer FGD control, and 3) Wet FGD control. These background studies were used by the EPA Clean Air Market Division for analysis of policy scenarios. Each of these three control technology descriptions will be discussed briefly and the methodology applied to the 162 MW Corette Powder River Basin (PRB) coal-fired steam generating unit.

Each document provides a concise summary of the approach to the cost development analysis, the empirical equations used in the approach, and an example of the application of the technique to a real case. All cost estimates are provided in 2009 dollars. To estimate the several engineering and construction contractor costs involved in the installation of retrofit controls, factors of the capital equipment cost are employed in such estimations just as EPA has historically done in the CCM.

Each S&L report is based on an approach tailored to the particular system and knowledge of the cost of installations in the S&L proprietary data base. Each analysis included a “retrofit factor” which is assumed in each case to be 1.0 to indicate an “average” difficulty of retrofit. Estimation of this factor appears to be a matter of judgement and comments are provided that indicates that large increases in costs can occur with particularly difficult sites. Corette is a very congested site with very little physical space for the installation of controls. PPL Montana assumes that a retrofit factor of 2.0 may reflect the additional costs associated with controls installation at the very space limited Corette facility and site specific conditions justify setting this factor at 2.0 (or higher) to account for balance of plant effects of the application of these SO_2 control technologies. Specifically, this site is constrained by a river to the east, a railroad to the west, and a small plant footprint. These factors complicate engineering, construction and tie-in of retrofit controls and significantly increase cost.

An important fact in the application of either dry sorbent injection or spray dryer absorption at Corette is that particulate loading to the ESP and emissions from that control device will increase if either SO_2 control option is installed. This will likely require an upgrade to the particulate control device to accompany one of those control options. In the January 2011 report “Potential Impacts of Environmental Regulation on the U.S. Generation Fleet” (Reference 4) the estimated retrofit cost for a pulse-jet fabric filter is estimated to be on the order of $379/kW in 2008 dollars. Such an upgrade to the particulate control equipment significantly increases the $/ton estimates of cost effectiveness for each of these possible SO_2 control options. Although such unintended consequences of secondary pollutant generation and the necessity of particulate control equipment upgrades were not considered in application of the IPM model cost analyses by Sargent & Lundy , LLC for these SO_2 control options, they are incorporated into these cost estimates using the referenced cost data.

3.1 The Effect of Coal Sulfur Content

In application of the costing techniques to the Corette PRB coal-fired boiler, it is important to note that PPL Montana already has lowered SO_2 emissions due to the burning of 0.3 wt percent Powder River Basin (PRB) coal. The plant has a long term contract for the 0.3% S fuel, however, the allowable sulfur in the operating permit for Corette is 2 lbs/MMBtu SO_2 (1% as S). Therefore, any SO_2 controls would need to accommodate the allowable sulfur content in coal in the design of equipment. This has the effect of increasing the capital cost of the SO_2 controls and making them less cost effective in actual operation.

3.2 Dry Sorbent Injection

In the dry sorbent injection technique (Attachment A-1), a milled powdered dry sorbent is injected into the ducting downstream of the air preheater but prior to the particulate control device. Trona is the dry sorbent of choice and up to a 70% control efficiency for SO_2 can be attained if a fabric filter is used for particulate control. However, at lower inlet SO_2 loadings this efficiency is reduced and for purposes of this evaluation, we have estimated that an outlet emission rate of 0.26 lbs SO_2/MMBtu can be achieved. This is consistent with recent emission rates that have been used in the industry. Baghouses have higher removal efficiencies due to the fact that a significant additional absorption in the fabric filter cake occurs. With electrostatic precipitators like Corette, the S&L model development document seems to indicate that a maximum of 40 to 50% SO_2 removal can be realized without an increase in particulate emissions. However, for purposes of this evaluation, because controlling the additional particulate will likely require particulate control equipment upgrades, the cost of these upgrades is included in the cost effectiveness calculations, significantly increasing the cost to apply these technologies at Corette.

The S&L dry sorbent injection cost evaluations used trona which is a mixture of sodium carbonate and sodium bicarbonate. This is the dry sorbent of choice where greater than 50% control of SO_2 is necessary. Trona is the most economic sorbent for Corette to use in the dry injection technique due to its local availability. The IPM costing study did not include dry sorbent injection costing in the options for the EPA planning evaluations. Facilities that used some type of dry sorbent injection were treated as uncontrolled sources because dry sorbent injection was assumed to have a removal efficiency of less than fifty percent. Nevertheless, for purposes of this study, the cost of dry injection technology has been included.

Dry sorbent injection technology costing is highly dependent on the inlet SO_2 concentration. Therefore, the empirical equations from S&L show that the capital costs are directly related to the trona injection rate. This technology option in particular must be oversized to accommodate potential inlet SO_2 concentrations up to the allowable limit of 2 lbs/MMBtu applicable to the Corette boiler.

3.3 Spray Dryer Absorption

The lime spray dryer absorber (SDA) technology option (Attachment A-2) is a semi-dry technology and the IPM costing techniques developed by S&L are based on numerous installed systems. The equipment needed to apply this control method includes a spray chamber, a lime/water mixing module, and waste handling equipment. While the costing analysis is based on 2 lbs/MMBtu SO_2, as in the case of dry injection, the operation of a system sized for 2 lbs/MMBtu SO_2 will be less cost effective when operated at the actual 30-day rolling average or even the maximum 24-hr SO_2 emission rate.

Numerous applications of SDA technology to PRB coal are in operation. It has shown the ability to reduce SO_2 emissions to 0.13 lbs/MMBtu with PRB coal. S&L cautions that this control option is only effective up to a 3 lbs/MMBtu uncontrolled SO_2 exhaust. As in the case of dry sorbent injection, particulate control using fabric filtration allows higher absorption of SO_2 by the effect of the filter cake on the absorption. Application of this technology will affect the plume buoyancy and require additional costs for reheat (see the discussion in Section 3.4). This is because in a SDA, a water slurry containing lime is sprayed into the gas stream, reducing plume temperature. The water injected partially saturates the exhaust, but only to within 50 degrees of the saturation temperature. The cost for plume reheating has been added to the costing analysis.

3.4 Wet Flue Gas Desulfurization (FGD)

The particular control technique included in the IPM study (Attachment A-3) is the limestone forced oxidation wet scrubbing (LSFO) technique. This technology was discussed by Srivastava (Reference 2) in his paper from 2001 that led to development of the cost estimation techniques in the EPA Fact Sheet used in the previous cost analyses by PPL. The cost analysis development for the IPM by S&L uses industry cost estimates not available until after the Srivastava studies that only produced the very broad ranges of costs.

Local SO_2 control requirements set plume buoyancy standards for the Corette Plant. Wet FGD will reduce plume buoyancy, necessitating a significant amount of reheat. In addition, there is very limited space at the facility to accommodate liquid impoundments and other related equipment for a wet FGD system including the installation of a new exhaust gas stack. Added retrofit costs to address plume buoyancy and the space required will significantly increase the cost of this technology making it infeasible for the Corette Plant.

The cost assessment has been based on a LSFO outlet SO_2 emission rate of 0.06 lbs/MMBtu.

4.0 COSTING ANALYSIS TABLES

Table 4-1 summarizes the equations used to calculate the control costs for each control technique as developed by S&L for the IPM. The cost development for each control technology is described by 5 spreadsheets labeled “a” through “e”. The first three are the application of the S&L cost equations specific for each technology Each worksheet is designed to be representative of the sample calculation sheets in the S&L cost descriptions, also provided in Attachments A-1, A-2, and A-3. The important empirical equations developed to represent the several portions of control technology costs are listed on a separate page and the first three costing analysis sheets make reference to this description of the equations.

The first sheet “a” is presented to develop the base equipment cost for each control option based on 2.0 lbs/MMBtu SO_2. Although Corette uses 0.3% S PRB coal, the allowable sulfur content is 1% and therefore any SO_2 controls must be applicable if the 0.3% S PRB coal supply were to be changed to a higher sulfur coal, still consistent with the allowable coal sulfur content. This spreadsheet was used to develop the capital cost estimate of the basic control technology.

The actual operation of the controls with lower inlet SO_2 concentrations, i.e., sheets “b” and “c” will consume lower quantities of reagent and therefore were prepared determine cost effectiveness based on the 30-day rolling average SO_2 concentration and the maximum 24-hr average SO_2 inlet values of 0.46 and 0.60 lbs/MMBtu respectively.

Likewise, spreadsheets “d” and “e” present the control costs in dollars per ton for 0.46 and 0.60 lbs/MMBtu SO_2 inlet concentrations respectively.

TABLE 4-1 EMPIRICAL EQUATIONS USED IN THE IPM MODEL CONTROL COSTING ANALYSES

The written descriptions below are presented to represent the S&L empirical equations used in their cost analysis methodology. The note numbers are found on worksheets in this section.

DRY SORBENT INJECTION

(Notes)

1 NSR or "K" = 0.353 x EXP(0.028 x H) {assumes ESP control and milled trona}
2 Trona feed rate or "M"= 1.2011 x 10^{-6} x K x A x C x D, {units are in tons/hour}
3 Sorbent waste rate or "N" = (0.7035 - 0.00073696 x H / K) x M {units are in tons/hour}
4 Fly ash waste rate or "P" = (A x C) x 0.06 ash in PRB coal x (1 - 0.2) / (2 x 8,400 Btu/lb)
5 Basic module cost = $7,516000 x B x $(M)^{0.284}$
6 Auxiliary power to run equipment = M x 20 / A {percent of gross plant power}

SPRAY DRYER ABSORBER

(Notes)

1 Lime rate = (0.6702 x $(D)^2$ + 13.42 x D) x A x C /10,000 / 2000 {units are in tons per hour}
2 Waste rate = (0.8016 x $(D)^2$ + 31.1917 x D) x A x C /10,000/2000 {units are in tons per hour}
3 Water rate = (0.04898 x $(D)^2$ +0.5925 x D + 55.11) x A X 1.05 x C/10,000/1000 {units are in 10^3 gals/hr}
4 Basic spray dryer equipment = $566,000 x $A^{0.716}$ x B x $(1.18)^{0.6}$ x $(D/4)^{0.01}$
5 Reagent prep equip cost = $300,000 x $A^{0.716}$ x B x $(D x G)^{0.2}$
6 Balance of SDA equipment = $799,000 x $A^{0.716}$ x B x $(F x G)^{0.6}$
7 Aux power to run equipment = (0.000547 x D^2 + 0.00649 x D + 1.3) x 1.18

WET FLUE GAS DESULFURIZATION

(Notes)

1 Limestone rate or "K" = 17.52 x A x D x G /2000 {units are in tons per hour}
2 Waste rate = limestone rate x 1.811 {units are in tons per hour}
3 Water rate = (1.674 x D + 74.68) x A x F x G / 1000 {units are in 10^3 gals/hr)
4 Basic absorber cost = $550,000 x $A^{0.716}$ x B x $(F X G)^{0.6}$ x $(D/2)^{0.02}$
5 Reagent prep equip cost = $190,000 x $A^{0.716}$ x $(D x G)^{0.3}$
6 Basic waste handling cost = $100,000 x $A^{0.716}$ x B x $(D x G)^{0.45}$
7 Balance of plant cost = $1,010,000 x B x $A^{0.716}$ x $(F X G)^{0.4}$
8 Aux power to run equipment = 1.05e^(0.155 x D) x F x G

Table 4-2a
DRY SORBENT INJECTION COSTING DEVELOPMENT
DESIGN CASE FOR CAPITAL COST

Variable	Designation	Units	Value	Equation/Input[1]
DRY INJECTION CAPITAL COST DESIGN BASIS FOR 2 LBS/MMBTU SO_2				
Unit Capacity (Gross)	A	(MW)	162	Input
Retrofit Factor	B		2	Difficulty of Retrofit
Gross heat rate	C	Btu/KW-hr	11,982	Input
SO_2 Emiss Rate	D	lbs/MMBtu	2	Uncontrolled
Type of Coal	E	PRB		Input
Particulate Control	F	ESP		Input
Trona Milling	G	Yes		Input
Removal Target	H		70	
Heat input	J	MM Btu/hr	1941.1	A X C x 1000
NSR	K		2.51	See Note DSI Note 1
Trona Feed rate	M	(tons/hr)	11.69	See Note DSI Note 2
Sorbent Waste Rate	N	(tons/hr)	7.98	See Note DSI Note 3
Fly Ash Waste Rate	P	(tons/hr)	5.55	See Note DSI Note 4
Aux Power	Q	(%)	1.44	See Note DSI Note 6
Trona Cost	R	($/ton)	150	
Waste Disposal Cost	S	($/ton)	50	
Aux Power Cost	T	($/kWhr)	0.06	
Operating Labor Rate	U	($/hr)	60	
CAPITAL EQUIPMENT COSTS				
Capital Cost	BM	($)	$30,215,380	Base DSI Module See note 5
Engineering, Construction Mgmt		5%	$1,510,769	
Construction Labor		5%	$1,510,769	
Contractor Profit and Fees		5%	$1,510,769	
Owners Cost		5%	$1,737,384	
Total Project Cost			$36,485,071	
			225	$/kW
OPERATING AND MAINTENANCE COSTS				
Fixed Operator Cost			$124,800	2,080 hrs- one operator
Maintenance Material			$302,154	1% of BM Capital Cost
Admin Labor Cost			$7,370	
Trona Cost			$1,752.82	Trona cost in $/hr
Waste Disposal Cost			$676.31	Total Waste Cost in $/hr

Notes:
1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-Dry Sorbent Injection Cost Development Methodology-FINAL", August 2010 Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

Table 4-2b
DRY SORBENT INJECTION COSTING DEVELOPMENT
30-DAY ROLLING AVERAGE OPERATIONAL PARAMETERS

Variable	Designation	Units	Value	Equation/Input[1]
DRY INJECTION OPERATING VARIABLES - ACTUAL OPERATION AT 0.46 LBS/MMBTU SO_2				
Unit Capacity (Gross)	A	(MW)	162	Input
Retrofit Factor	B		2	Difficulty of Retrofit
Gross heat rate	C	Btu/KW-hr	11,982	Input
SO_2 Emiss Rate	D	lbs/MMBtu	0.46	Uncontrolled
Type of Coal	E	PRB		Input
Particulate Control	F	ESP		Input
Trona Milling	G	Yes		Input
Removal Target	H		53	
Heat input	J	MM Btu/hr	1941.1	A X C x 1000
NSR	K		1.56	See Note DSI Note 1
Trona Feed rate	M	(tons/hr)	1.67	See Note DSI Note 2
Sorbent Waste Rate	N	(tons/hr)	1.13	See Note DSI Note 3
Fly Ash Waste Rate	P	(tons/hr)	5.55	See Note DSI Note 4
Aux Power	Q	(%)	0.21	See Note DSI Note 6
Trona Cost	R	($/ton)	150	Corrected to 2011 $
Waste Disposal Cost	S	($/ton)	50	
Aux Power Cost	T	($/kWhr)	0.06	
Operating Labor Rate	U	($/hr)	60	
CAPITAL EQUIPMENT COSTS				
Capital Cost	BM	($)	$17,387,979	Base DSI Module
Engineering, Construction Mgmt		5%	$869,399	
Construction Labor		5%	$869,399	
Contractor Profit and Fees		5%	$869,399	
Owners Cost		5%	$999,809	
Total Project Cost			$20,995,984	
			130	$/kW
OPERATING AND MAINTENANCE COSTS				
Fixed Operator Cost			$124,800	2,080 hrs- one operator
Maintenance Material			$173,880	1% of BM Capital Cost
Admin Labor Cost			$5,831	
Trona Cost			$250.46	Trona cost in $/hr
Waste Disposal Cost			$333.94	Total Waste Cost in $/hr

Notes:
1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-Dry Sorbent Injection Cost Development Methodology-FINAL", August 2010 Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

Table 4-2c
DRY SORBENT INJECTION COSTING DEVELOPMENT
MAX 24-HR SO_2 OPERATIONAL PARAMETERS

Variable	Designation	Units	Value	Equation/Input[1]
DRY INJECTION OPERATING VARIABLES - ACTUAL OPERATION AT 0.60 LBS/MMBTU SO_2				
Unit Capacity (Gross)	A	(MW)	162	Input
Retrofit Factor	B		2	Difficulty of Retrofit
Gross heat rate	C	Btu/KW-hr	11,982	Input
SO_2 Emiss Rate	D	lbs/MMBtu	0.6	Uncontrolled
Type of Coal	E	PRB		Input
Particulate Control	F	ESP		Input
Trona Milling	G	Yes		Input
Removal Target	H		57	
Heat input	J	MM Btu/hr	1941.1	A X C x 1000
NSR	K		1.74	See Note DSI Note 1
Trona Feed rate	M	(tons/hr)	2.44	See Note DSI Note 2
Sorbent Waste Rate	N	(tons/hr)	1.65	See Note DSI Note 3
Fly Ash Waste Rate	P	(tons/hr)	5.55	See Note DSI Note 4
Aux Power	Q	(%)	0.30	See Note DSI Note 6
Trona Cost	R	($/ton)	150	Corrected to 2011 $
Waste Disposal Cost	S	($/ton)	50	
Aux Power Cost	T	($/kWhr)	0.06	
Operating Labor Rate	U	($/hr)	60	
CAPITAL EQUIPMENT COSTS				
Capital Cost	BM	($)	$19,356,858	Base DSI Module
Engineering, Construction Mgmt		5%	$967,843	
Construction Labor		5%	$967,843	
Contractor Profit and Fees		5%	$967,843	
Owners Cost		5%	$1,113,019	
Total Project Cost		5%	$23,373,406	
			144	$/kW
OPERATING AND MAINTENANCE COSTS				
Fixed Operator Cost			$124,800	2,080 hrs- one operator
Maintenance Material			$193,569	1% of BM Capital Cost
Admin Labor Cost			$6,067	
Trona Cost			$365.41	Trona cost in $/hr
Waste Disposal Cost			$360.05	Waste Cost in $/hr

Notes:
1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-Dry Sorbent Injection Cost Development Methodology-FINAL", August 2010 Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

Table 4-2d
PPL BART Cost Effectiveness Analysis
Dry Injection (With Low Sulfur Coal) Sulfur Dioxide Control
162 Megawatt Coal Fired Steam Electric Plant
Trona Injection With Precipitator Replacement at J.E. Corette
SO_2 =0.46 lbs/MMBtu

Stack Exhaust Volumetric Flowrate, (acfm)	Q	726,262
Maximum Gross Heat Input	MM Btu/hr	1,941
Design Percent Load	%	89
Uncontrolled SO2 Emissions (with low S coal)	lbs/MMBtu	0.460
ExhaustTemperature, (^oF)	T	405
Steam Turbine Power Output (TMW)	MW	162
Capacity Factor (89%)	hrs	7,796
Controlled SO2 Emissions	lbs/MMBtu	0.26
Overall SO2 Reduction Efficiency, (%)	%	43.48
Uncontrolled SO2 Emissions, (lb/hr)		892.9
Uncontrolled SO2 Emissions, (tons/yr)		3480.7
Controlled SO2 Emissions, (ton/yr)		1967.4
Annual Interest Rate, (%)		7
Equipment Life, (yrs)	yr	15
Capital Recovery Factor, CRF	CRF	0.1098

Cost Item	Suggested Factor	Unit Cost	Item Cost
IPM Model, August 20, 2010[1]	Capital Cost ($/KW)[2]	225	$36,485,071
Cost for Pulse-Jet Fabric Filter	Capital Cost ($/KW)[3]	379	$61,398,000
Equipment Cost Total, (EC)	EC (Adjusted by Cost Index Calcs)	(2011 dollars)[4]	$101,615,582
Total Capital Costs, TCC		---	$101,615,582
Direct Annual Costs, DAC	Trona Cost		$1,952,695
	Total waste disposal Cost		$2,603,502
	Parasitic power cost		$156,216
	Lost Ash Revenue	$11.74/ton	$352,200
	Maintenance Labor		$130,631
	Maintenance Materials		$173,880
Total Direct Annual Costs, DAC			$5,369,123
Indirect Annual Costs			
Capital Recovery	CRF*TCC	---	$11,156,845
Total Indirect Annual Costs, IAC			$11,156,845
Total Annual Costs, TAC = DAC + IAC			$16,525,967
Cost Effectiveness ($/ton pollutant Removed)			$10,920

Cost data references:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-Dry Sorbent Injection Cost Development Methodology-FINAL", August 2010 Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

2) $/kW in 2009 dollars

3) $/kW in 2008 dollars (See Edison Electric Institute reference on page 26)

4) Cost indices used to adjust 2008 and 2009 costs to 2011 costs (2008, 2009 CI= 108.302, 109.594 2011 CI= 113.065)

Table 4-2e
PPL BART Cost Effectiveness Analysis
Dry Injection (With Low Sulfur Coal) Sulfur Dioxide Control
162 Megawatt Coal Fired Steam Electric Plant
Trona Injection With Precipitator Replacement at J.E. Corette
SO_2 =0.60 lbs/MMBtu

Stack Exhaust Volumetric Flowrate, (acfm)	Q	726,262
Maximum Gross Heat Input	MM Btu/hr	1,941
Design Percent Load	%	89
Uncontrolled SO2 Emissions (with low S coal)	lbs/MMBtu	0.600
ExhaustTemperature, (^oF)	T	405
Steam Turbine Power Output (TMW)	MW	162
Capacity Factor (89%)	hrs	7,796
Controlled SO2 Emissions	lbs/MMBtu	0.26
Overall SO2 Reduction Efficiency, (%)	%	56.67
Uncontrolled SO2 Emissions, (lb/hr)		1164.7
Uncontrolled SO2 Emissions, (tons/yr)		4540.1
Controlled SO2 Emissions, (ton/yr)		1967.4
Annual Interest Rate, (%)		7
Equipment Life, (yrs)	yr	15
Capital Recovery Factor, CRF	CRF	0.1098

Cost Item	Suggested Factor	Unit Cost	Item Cost
IPM Model, August 20, 2010[1]	Capital Cost ($/KW)[2]	225	$36,485,071
Cost for Pulse-Jet Fabric Filter	Capital Cost ($/KW)[3]	379	$61,398,000
Equipment Cost Total, (EC)	EC (Adjusted by Cost Index Calcs)	(2011 dollars)[4]	$101,615,582
Total Capital Costs, TCC		---	$101,615,582
Direct Annual Costs, DAC	Trona Cost		$2,848,845
	Total waste disposal Cost		$2,807,072
	Parasitic power cost		$227,908
	Lost Ash Revenue	$11.74/ton	$352,200
	Maintenance Labor		$130,867
	Maintenance Materials		$193,569
Total Direct Annual Costs, DAC			$6,560,460
Indirect Annual Costs			
Capital Recovery	CRF*TCC	---	$11,156,845
Total Indirect Annual Costs, IAC			$11,156,845
Total Annual Costs, TAC = DAC + IAC			$17,717,304
Cost Effectiveness ($/ton pollutant Removed)			$6,887

Cost data references:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-Dry Sorbent Injection Cost Development Methodology-FINAL", August 2010 Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

2) $/kW in 2009 dollars

3) $/kW in 2008 dollars (See Edison Electric Institute reference on page 26)

4) Cost indices used to adjust 2008 and 2009 costs to 2011 costs (2008, 2009 CI= 108.302, 109.594 2011 CI= 113.065)

Table 4-3a

SPRAY DRYER ABSORBER COSTING DEVELOPMENT

DESIGN CASE FOR CAPITAL COSTS

Variable	Designation	Units	Value	Equation/Input[1]
LIME SPRAY DRYER CAPITAL COST DESIGN BASIS FOR 2 LBS/MMBTU SO_2				
Unit Capacity (Gross)	A	(MW)	162	Input
Retrofit Factor	B		2	Difficulty of Retrofit
Gross heat rate	C	Btu/KW-hr	11,982	Input
SO_2 Emiss Rate	D	lbs/MMBtu	2	Uncontrolled
Type of Coal	E	PRB		Input
Coal Factor	F	PRB Coal	1.05	Input
Heat Rate Factor	G		1.20	C / 10000
Heat input	H	MM Btu/hr	1941.1	A X C x 1000
Lime Rate	K	(tons/hr)	2.87	See SDA Note 1
Waste Rate	L	(tons/hr)	6.37	See SDA Note 2
Aux Power	M	(%)	1.65	See SDA Note 7
Make Up Water	N	10^3 gph	11.51	See SDA Note 3
Lime Cost	P	($/ton)	135.00	Input
Waste Disposal Cost	S	($/ton)	50	Input
Aux Power Cost	R	($/kWhr)	0.06	Input
Makeup Water Cost	S	$/$10^3$ gal	1	Input
Operating Labor Rate	T	($/hr)	60	Input
CAPITAL EQUIPMENT COSTS				
Basic Absorber	BMR	($)	$49,281,061	See SDA Note 4
Reagent Preparation	BMF	($)	$27,294,545	See SDA Note 5
ID Fan, Other Costs	BMB	($)	$66,907,834	See SDA Note 6
Capital Cost	BM Sum	($)	$143,483,440	Base LSD Module
Engineering, Construction Mgmt		10%	$14,348,344	
Construction Labor		10%	$14,348,344	
Contractor Fees		10%	$14,348,344	
	CECC		$186,528,472	Capital, Eng, and Const
Owners Cost	B1	5%	$9,326,424	Various home office fees
AFUDC		10% of (CECC+B1)	$19,585,490	
Total Project Cost			$215,440,385	
			1,330	$/kW
OPERATING AND MAINTENANCE COSTS				
Fixed Operator Cost			$998,400	2,080 hrs- 8 operators
Maintenance Material			$4,304,503	1.5% of BM Capital Cost
Admin Labor Cost			$81,606	
Lime Cost			$386.79	Lime cost in $/hr
Waste Disposal Cost			$318.29	Waste Cost in $/hr

Notes:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-SDA FDG Cost Development Methodology-FINAL", August 2010

Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

Table 4-3b
SPRAY DRYER COSTING DEVELOPMENT
30-DAY ROLLING AVERAGE SO_2 OPERATING PARAMETERS

Variable	Designation	Units	Value	Equation/Input[1]
LIME SPRAY DRYER OPERATING VARIABLES - ACTUAL OPERATION AT 0.46 LBS/MMBTU SO_2				
Unit Capacity (Gross)	A	(MW)	162	Input
Retrofit Factor	B		2	Difficulty of Retrofit
Gross heat rate	C	Btu/KW-hr	11,982	Input
SO_2 Emiss Rate	D	lbs/MMBtu	0.46	Uncontrolled
Type of Coal	E	PRB		Input
Coal Factor	F	PRB Coal	1.05	Input
Heat Rate Factor	G		1.20	C / 10000
Heat input	H	MM Btu/hr	1941.1	A X C x 1000
Lime Rate	K	(tons/hr)	0.61	See SDA Note 1
Waste Rate	L	(tons/hr)	1.41	See SDA Note 2
Aux Power	M	(%)	1.64	See SDA Note 7
Make Up Water	N	10^3 gph	11.29	See SDA Note 3
Lime Cost	P	($/ton)	135.00	Input
Waste Disposal Cost	S	($/ton)	50	Input
Aux Power Cost	R	($/kWhr)	0.06	Input
Makeup Water Cost	S	$/$10^3$ gal	1	Input
Operating Labor Rate	T	($/hr)	60	Input
CAPITAL EQUIPMENT COSTS				
Basic Absorber	BMR	($)	$48,562,085	See SDA Note 4
Reagent Preparation	BMF	($)	$20,343,301	See SDA Note 5
ID Fan, Other Costs	BMB	($)	$66,907,834	See SDA Note 6
Capital Cost	BM Sum	($)	$135,813,220	Base LSD Module
Engineering, Construction Mgmt		10%	$13,581,322	
Construction Labor		10%	$13,581,322	
Contractor Fees		10%	$13,581,322	
	CECC		$176,557,186	Capital, Eng, and Const
Owners Cost	B1	5%	$8,827,859	Various home office fees
AFUDC		10% of (CECC+B1)	$18,538,505	
Total Project Cost			$203,923,550	
			1,259	$/kW
OPERATING AND MAINTENANCE COSTS				
Fixed Operator Cost			$998,400	2,080 hrs- 8 operators
Maintenance Material			$4,074,397	1.5% of BM Capital Cost
Admin Labor Cost			$78,845	
Lime Cost			$82.74	Lime cost in $/hr
Waste Disposal Cost			$70.45	Waste Cost in $/hr

Notes:
1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-SDA FDG Cost Development Methodology-FINAL", August 2010
Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

Table 4-3c

SPRAY DRYER ABSORBER COSTING DEVELOPMENT

MAXIMUM 24-HR AVERAGE SO_2 OPERATING PARAMETERS

Variable	Designation	Units	Value	Equation/Input[1]
LIME SPRAY DRYER OPERATING VARIABLES - ACTUAL OPERATION AT 0.60 LBS/MMBTU SO_2				
Unit Capacity (Gross)	A	(MW)	162	Input
Retrofit Factor	B		2	Difficulty of Retrofit
Gross heat rate	C	Btu/KW-hr	11,982	Input
SO_2 Emiss Rate	D	lbs/MMBtu	0.6	Uncontrolled
Type of Coal	E	PRB		Input
Coal Factor	F	PRB Coal	1.05	Input
Heat Rate Factor	G		1.20	C / 10000
Heat input	H	MM Btu/hr	1941.1	A X C x 1000
Lime Rate	K	(tons/hr)	0.80	See SDA Note 1
Waste Rate	L	(tons/hr)	1.84	See SDA Note 2
Aux Power	M	(%)	1.64	See SDA Note 7
Make Up Water	N	10^3 gph	11.31	See SDA Note 3
Lime Cost	P	($/ton)	135.00	Input
Waste Disposal Cost	S	($/ton)	50	Input
Aux Power Cost	R	($/kWhr)	0.06	Input
Makeup Water Cost	S	$/$10^3$ gal	1	Input
Operating Labor Rate	T	($/hr)	60	Input
CAPITAL EQUIPMENT COSTS				
Basic Absorber	BMR	($)	$48,691,288	See SDA Note 4
Reagent Preparation	BMF	($)	$21,453,597	See SDA Note 5
ID Fan, Other Costs	BMB	($)	$66,907,834	See SDA Note 6
Capital Cost	BM Sum	($)	$137,052,718	Base LSD Module
Engineering, Construction Mgmt		10%	$13,705,272	
Construction Labor		10%	$13,705,272	
Contractor Fees		10%	$13,705,272	
	CECC		$178,168,534	Capital, Eng, and Const
Owners Cost	B1	5%	$8,908,427	Various home office fees
AFUDC		10% of (CECC+B1)	$18,707,696	
Total Project Cost			$205,784,657	
			1,270	$/kW
OPERATING AND MAINTENANCE COSTS				
Fixed Operator Cost			$998,400	2,080 hrs- 8 operators
Maintenance Material			$4,111,582	1.5% of BM Capital Cost
Admin Labor Cost			$79,291	
Lime Cost			$108.66	Lime cost in $/hr
Waste Disposal Cost			$92.22	Waste Cost in $/hr

Notes:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-SDA FDG Cost Development Methodology-FINAL", August 2010 Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

Table 4-3d
PPL BART Cost Effectiveness Analysis
Lime Spray Drying (With Low Sulfur Coal) Sulfur Dioxide Control
162 Megawatt Coal Fired Steam Electric Plant
Lime Spray Drying With Precipitator Replacement at J.E. Corette
SO_2 =0.46 lbs/MMBtu

Stack Exhaust Volumetric Flowrate, (acfm)	Q	726,262
Maximum Gross Heat Input	MM Btu/hr	1,941
Design Percent Load	%	89
Uncontrolled SO2 Emissions (with low S coal)	lbs/MMBtu	0.460
ExhaustTemperature, (^oF)	T	405
Steam Turbine Power Output (TMW)	MW	162
Capacity Factor (89%)	hrs	7,796
Controlled SO2 Emissions	lbs/MMBtu	0.13
Overall SO2 Reduction Efficiency, (%)	%	71.74
Uncontrolled SO2 Emissions, (lb/hr)		892.9
Uncontrolled SO2 Emissions, (tons/yr)		3480.7
Controlled SO2 Emissions, (ton/yr)		983.7
Annual Interest Rate, (%)		7
Equipment Life, (yrs)	yr	15
Capital Recovery Factor, CRF	CRF	0.1098

Cost Item	Suggested Factor	Unit Cost	Item Cost
IPM Model, August 20, 2010[1]	Capital Cost ($/KW)[2]	1,330	$215,440,385
Cost for Pulse-Jet Fabric Filter	Capital Cost ($/KW)[3]	379	$61,398,000
Equipment Cost Total, (EC)	EC (Adjusted by Cost Index Calcs)	(2011 dollars)[4]	$285,634,195
Total Capital Costs, TCC		---	$285,634,195
Direct Annual Costs, DAC	Lime		$645,084
	Total waste disposal Cost		$549,262
	Parasitic power cost		$1,242,388
	Lost Ash Revenue	$11.74/ton	$352,200
	Stack Reheat Penalty	reheat to 300^oF	$7,740,315
	Maintenance labor		$1,077,245
	Maintenance materials		$4,074,397
Total Direct Annual Costs, DAC			$15,680,890
Indirect Annual Costs			
Capital Recovery	CRF*TCC	---	$31,361,099
Total Indirect Annual Costs, IAC			$31,361,099
Total Annual Costs, TAC = DAC + IAC			$47,041,990
Cost Effectiveness ($/ton pollutant Removed)			$18,839

Cost data references:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-Dry Sorbent Injection Cost Development Methodology-FINAL", August 2010 Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

2) $/kW in 2009 dollars

3) $/kW in 2008 dollars (See Edison Electric Institute reference on page 26)

4) Cost indices used to adjust 2008 and 2009 costs to 2011 costs (2008, 2009 CI= 108.302, 109.594 2011 CI= 113.065)

Table 4-3e
PPL BART Cost Analysis
Lime Spray Drying (With Low Sulfur Coal) Sulfur Dioxide Control
162 Megawatt Coal Fired Steam Electric Plant
Lime Spray Drying With Precipitator Replacement at J.E. Corette
SO_2 =0.60 lbs/MMBtu

Stack Exhaust Volumetric Flowrate, (acfm)	Q	726,262
Maximum Gross Heat Input	MM Btu/hr	1,941
Design Percent Load	%	89
Uncontrolled SO2 Emissions (with low S coal)	lbs/MMBtu	0.600
ExhaustTemperature, (^oF)	T	405
Steam Turbine Power Output (TMW)	MW	162
Capacity Factor (89%)	hrs	7,796
Controlled SO2 Emissions	lbs/MMBtu	0.13
Overall SO2 Reduction Efficiency, (%)	%	78.33
Uncontrolled SO2 Emissions, (lb/hr)		1164.7
Uncontrolled SO2 Emissions, (tons/yr)		4540.1
Controlled SO2 Emissions, (ton/yr)		983.7
Annual Interest Rate, (%)		7
Equipment Life, (yrs)	yr	15
Capital Recovery Factor, CRF	CRF	0.1098

Cost Item	Suggested Factor	Unit Cost	Item Cost
IPM Model, August 20, 2010[(1)]	Capital Cost ($/KW)[(2)]	1,330	$215,440,385
Cost for Pulse-Jet Fabric Filter	Capital Cost ($/KW)[(3)]	379	$61,398,000
Equipment Cost Total, (EC)	EC (Adjusted by Cost Index Calcs)	(2011 dollars)[(4)]	$285,634,195
Total Capital Costs, TCC		---	$285,634,195
Direct Annual Costs, DAC	Lime		$847,165
	Total waste disposal Cost		$718,976
	Parasitic power cost		$1,243,331
	Lost Ash Revenue	$11.74/ton	$352,200
	Stack Reheat Penalty	reheat to 300^{o}F	$7,740,315
	Maintenance labor		$1,077,691
	Maintenance materials		$4,111,582
Total Direct Annual Costs, DAC			$16,091,260
Indirect Annual Costs			
Capital Recovery	CRF*TCC	---	$31,361,099
Total Indirect Annual Costs, IAC			$31,361,099
Total Annual Costs, TAC = DAC + IAC			$47,452,359
Cost Effectiveness ($/ton pollutant Removed)			$13,343

Cost data references:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-Dry Sorbent Injection Cost Development Methodology-FINAL", August 2010 Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC
2) $/kW in 2009 dollars
3) $/kW in 2008 dollars (See Edison Electric Institute reference on page 26)
4) Cost indices used to adjust 2008 and 2009 costs to 2011 costs (2008, 2009 CI= 108.302, 109.594 2011 CI= 113.065)

Table 4-4a
WET FGD COSTING DEVELOPMENT
DESIGN BASIS FOR CAPITAL COST

Variable	Designation	Units	Value	Equation/Input[1]
WET FGD CAPITAL COST DESIGN BASIS FOR 2 LBS/MMBTU SO_2				
Unit Capacity (Gross)	A	(MW)	162	Input
Retrofit Factor	B		2	Difficulty of Retrofit
Gross heat rate	C	Btu/KW-hr	11,982	Input
SO_2 Emiss Rate	D	lbs/MMBtu	2	Uncontrolled
Type of Coal	E	PRB		Input
Coal Factor	F	PRB Coal	1.05	Input
Heat Rate Factor	G		1.20	C / 10000
Heat input	H	MM Btu/hr	1941.1	A X C x 1000
Limestone Rate	K	(tons/hr)	3.40	See FGD Note 1
Waste Rate	L	(tons/hr)	6.16	See FGD Note 2
Aux Power	M	(%)	1.80	See FGD Note 8
Make Up Water	N	10^3 gph	15.90	See FGD Note 3
Limestone Cost	P	($/ton)	15.00	
Waste Disposal Cost	S	($/ton)	50	
Aux Power Cost	R	($/kWhr)	0.06	
Makeup Water Cost	S	$/$10^3$ gal	1	
Operating Labor Rate	T	($/hr)	60	
CAPITAL EQUIPMENT COSTS				
Basic Absorber	BMR	($)	$48,221,043	See FGD Note 4
Reagent Preparation	BMF	($)	$18,865,318	See FGD Note 5
Waste Handling Cost	BMW	($)	$11,319,948	See FGD Note 6
ID Fan, Other Costs	BMB	($)	$84,576,862	See FGD Note 7
Capital Cost	BM Sum	($)	$162,983,172	Base Wet FGD Module
Engineering, Construction Mgmt		10%	$16,298,317	
Construction Labor		10%	$16,298,317	
Contractor Fees		10%	$16,298,317	
	CECC		$211,878,123	Capital, Eng, and Const
Owners Cost	B1	5%	$10,593,906	Various home office fees
AFUDC		10% of (CECC+B1)	$22,247,203	
Total Project Cost			$244,719,232	
			1,511	$/kW
OPERATING AND MAINTENANCE COSTS				
Fixed Operator Cost	FOMO		$1,497,600	2,080 hrs- 12 operators
Maintenance Material			$4,889,495	1.5% of BM Capital Cost
Admin Labor Cost			$103,602	
Auxiliary Power			$175.07	$/hr
Water Cost			$15.90	$/hr
Limestone Cost			$323.07	Limestone cost in $/hr
Waste Disposal Cost			$307.94	Waste Cost in $/hr

Notes:
1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-Wet FGD Cost Development Methodology-FINAL", August 2010
Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

Table 4-4b
WET FGD COSTING DEVELOPMENT
30-DAY ROLLING AVERAGE SO_2 OPERATING PARAMETERS

Variable	Designation	Units	Value	Equation/Input[1]
WET FGD OPERATING VARIABLES - ACTUAL OPERATION AT 0.46 LBS/MMBTU SO_2				
Unit Capacity (Gross)	A	(MW)	162	Input
Retrofit Factor	B		2	Difficulty of Retrofit
Gross heat rate	C	Btu/KW-hr	11,982	Input
SO_2 Emiss Rate	D	lbs/MMBtu	0.46	Uncontrolled
Type of Coal	E	PRB		Input
Coal Factor	F	PRB Coal	1.05	Input
Heat Rate Factor	G		1.20	C / 10000
Heat input	H	MM Btu/hr	1941.1	A X C x 1000
Limestone Rate	K	(tons/hr)	0.78	See FGD Note 1
Waste Rate	L	(tons/hr)	1.42	See FGD Note 2
Aux Power	M	(%)	1.42	See FGD Note 8
Make Up Water	N	10^3 gph	15.38	See FGD Note 3
Limestone Cost	P	($/ton)	15.00	
Waste Disposal Cost	S	($/ton)	50	
Aux Power Cost	R	($/kWhr)	0.06	
Makeup Water Cost	S	$/$10^3$ gal	1	
Operating Labor Rate	T	($/hr)	60	
CAPITAL EQUIPMENT COSTS				
Basic Absorber	BMR	($)	$46,824,286	See FGD Note 4
Reagent Preparation	BMF	($)	$12,138,988	See FGD Note 5
Waste Handling Cost	BMW	($)	$5,842,813	See FGD Note 6
ID Fan, Other Costs	BMB	($)	$84,576,862	See FGD Note 7
Capital Cost	BM Sum	($)	$149,382,948	Base Wet FGD Module
Engineering, Construction Mgmt		10%	$14,938,295	
Construction Labor		10%	$14,938,295	
Contractor Fees		10%	$14,938,295	
	CECC		$194,197,833	Capital, Eng, and Const
Owners Cost	B1	5%	$9,709,892	Various home office fees
AFUDC		10% of (CECC+B1)	$20,390,772	
Total Project Cost			$224,298,497	
			1,385	$/kW
OPERATING AND MAINTENANCE COSTS				
Fixed Operator Cost	FOMO		$1,497,600	2,080 hrs- 12 operators
Maintenance Material			$4,481,488	1.5% of BM Capital Cost
Admin Labor Cost			$98,706	
Auxiliary Power			$137.89	$/hr
Water Cost			$15.38	$/hr
Limestone Cost			$74.31	Limestone cost in $/hr
Waste Disposal Cost			$70.83	Waste Cost in $/hr

Notes:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-Wet FGD Cost Development Methodology-FINAL", August 2010
Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

Table 4-4c
WET FGD COSTING DEVELOPMENT
MAXIMUM 24-HR AVERAGE SO_2 OPERATING PARAMETERS

Variable	Designation	Units	Value	Equation/Input[1]
WET FGD OPERATING VARIABLES - ACTUAL OPERATION AT 0.60 LBS/MMBTU SO_2				
Unit Capacity (Gross)	A	(MW)	162	Input
Retrofit Factor	B		2	Difficulty of Retrofit
Gross heat rate	C	Btu/KW-hr	11,982	Input
SO_2 Emiss Rate	D	lbs/MMBtu	0.6	Uncontrolled
Type of Coal	E	PRB		Input
Coal Factor	F	PRB Coal	1.05	Input
Heat Rate Factor	G		1.20	C / 10000
Heat input	H	MM Btu/hr	1941.1	A X C x 1000
Limestone Rate	K	(tons/hr)	1.02	See FGD Note 1
Waste Rate	L	(tons/hr)	1.85	See FGD Note 2
Aux Power	M	(%)	1.45	See FGD Note 8
Make Up Water	N	10^3 gph	15.43	See FGD Note 3
Limestone Cost	P	($/ton)	15.00	
Waste Disposal Cost	S	($/ton)	50	
Aux Power Cost	R	($/kWhr)	0.06	
Makeup Water Cost	S	$/$10^3$ gal	1	
Operating Labor Rate	T	($/hr)	60	
CAPITAL EQUIPMENT COSTS				
Basic Absorber	BMR	($)	$47,073,775	See FGD Note 4
Reagent Preparation	BMF	($)	$13,146,209	See FGD Note 5
Waste Handling Cost	BMW	($)	$6,584,897	See FGD Note 6
ID Fan, Other Costs	BMB	($)	$84,576,862	See FGD Note 7
Capital Cost	BM Sum	($)	$151,381,743	Base Wet FGD Module
Engineering, Construction Mgmt		10%	$15,138,174	
Construction Labor		10%	$15,138,174	
Contractor Fees		10%	$15,138,174	
	CECC		$196,796,265	Capital, Eng, and Const
Owners Cost	B1	5%	$9,839,813	Various home office fees
AFUDC		10% of (CECC+B1)	$20,663,608	
Total Project Cost			$227,299,686	
			1,403	$/kW
OPERATING AND MAINTENANCE COSTS				
Fixed Operator Cost	FOMO		$1,497,600	2,080 hrs- 12 operators
Maintenance Material			$4,541,452	1.5% of BM Capital Cost
Admin Labor Cost			$99,425	
Auxiliary Power			$140.92	$/hr
Water Cost			$15.43	$/hr
Limestone Cost			$96.92	Limestone cost in $/hr
Waste Disposal Cost			$92.38	Waste Cost in $/hr

Notes:
1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-Wet FGD Cost Development Methodology-FINAL", August 2010
Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

Table 4-4d
PPL BART Cost Analysis
Wet FGD (With Low Sulfur Coal) Sulfur Dioxide Control
162 Megawatt Coal Fired Steam Electric Plant
Wet FGD at J.E. Corette
SO_2 =0.46 lbs/MMBtu

Stack Exhaust Volumetric Flowrate, (acfm)	Q	726,262
Maximum Gross Heat Input	MM Btu/hr	1,941
Design Percent Load	%	89
Uncontrolled SO2 Emissions (with low S coal)	lbs/MMBtu	0.460
ExhaustTemperature, (^oF)	T	405
Steam Turbine Power Output (TMW)	MW	162
Capacity Factor (89%)	hrs	7,796
Controlled SO2 Emissions	lbs/MMBtu	0.06
Overall SO2 Reduction Efficiency, (%)	%	86.96
Uncontrolled SO2 Emissions, (lb/hr)		892.9
Uncontrolled SO2 Emissions, (tons/yr)		3480.7
Controlled SO2 Emissions, (ton/yr)		454.0
Annual Interest Rate, (%)		7
Equipment Life, (yrs)	yr	15
Capital Recovery Factor, CRF	CRF	0.1098

Cost Item	Suggested Factor	Unit Cost	Item Cost
IPM Model, August 20, 2010[1]	Capital Cost ($/KW)[2]	1,511	$244,719,232
Equipment Cost Total, (EC)	EC (Adjusted by Cost Index Calcs)	(2011 dollars)[3]	$252,469,843
Total Capital Costs, TCC		---	$252,469,843
Direct Annual Costs, DAC	Limestone Cost		$579,327
	Waste disposal Cost		$552,190
	Parasitic power cost		$1,075,062
	Lost Ash Revenue	$11.74/ton	$352,200
	Stack Reheat Penalty	reheat to 300^oF	$10,965,447
	Operator and Admin Labor		$1,596,306
	Maintenance Materials		$4,481,488
Total Direct Annual Costs, DAC			$19,602,020
Indirect Annual Costs			
Capital Recovery	CRF*TCC	---	$27,719,832
Total Indirect Annual Costs, IAC			$27,719,832
Total Annual Costs, TAC = DAC + IAC			$47,321,852
Cost Effectiveness ($/ton pollutant Removed)			$15,635

Cost data references:
1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-Wet FGD Cost Development Methodology-FINAL", August 2010
Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC
2) $/kW in 2009 dollars
3) Cost indices used to adjust 2009 costs to 2011 costs (2009 CI= 109.954, 2011 CI= 113.065)

Table 4-4e
PPL BART Cost Analysis
Wet FGD (With Low Sulfur Coal) Sulfur Dioxide Control
162 Megawatt Coal Fired Steam Electric Plant
Wet FGD at J.E. Corette
SO_2 =0.60 lbs/MMBtu

Stack Exhaust Volumetric Flowrate, (acfm)	Q	726,262
Maximum Gross Heat Input	MM Btu/hr	1,941
Design Percent Load	%	89
Uncontrolled SO2 Emissions (with low S coal)	lbs/MMBtu	0.600
ExhaustTemperature, (°F)	T	405
Steam Turbine Power Output (TMW)	MW	162
Capacity Factor (89%)	hrs	7,796
Controlled SO2 Emissions	lbs/MMBtu	0.06
Overall SO2 Reduction Efficiency, (%)	%	90.00
Uncontrolled SO2 Emissions, (lb/hr)		1164.7
Uncontrolled SO2 Emissions, (tons/yr)		4540.1
Controlled SO2 Emissions, (ton/yr)		454.0
Annual Interest Rate, (%)		7
Equipment Life, (yrs)	yr	15
Capital Recovery Factor, CRF	CRF	0.1098

Cost Item	Suggested Factor	Unit Cost	Item Cost
IPM Model, August 20, 2010[1]	Capital Cost ($/KW)[2]	1,511	$244,719,232
Equipment Cost Total, (EC)	EC (Adjusted by Cost Index Calcs)	(2011 dollars)[3]	$252,469,843
Total Capital Costs, TCC		---	$252,469,843
Direct Annual Costs, DAC	Limestone Cost		$755,644
	Waste disposal Cost		$720,248
	Parasitic power cost		$1,098,646
	Lost Ash Revenue	$11.74/ton	$352,200
	Stack Reheat Penalty	reheat to 300°F	$10,965,447
	Operator and Admin Labor		$1,596,306
	Maintenance Materials		$4,541,452
Total Direct Annual Costs, DAC			$20,029,943
Indirect Annual Costs			
Capital Recovery	CRF*TCC	---	$27,719,832
Total Indirect Annual Costs, IAC			$27,719,832
Total Annual Costs, TAC = DAC + IAC			$47,749,775
Cost Effectiveness ($/ton pollutant Removed)			$11,686

Cost data references:
1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-Wet FGD Cost Development Methodology-FINAL", August 2010 Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC
2) $/kW in 2009 dollars
3) Cost indices used to adjust 2009 costs to 2011 costs (2009 CI= 109.954, 2011 CI= 113.065)

5.0 REFERENCES

1) Documentation for EPA EPA Base Case v.4.10 Using the Integrated Planning Model (see URL).
2) Srivastava, Ravi K., SO_2 Scrubbing Technologies – A Review, Environmental Progress, December 2001
3) EPA, Air Pollution Control Technology Fact Sheet, US EPA, EPA-452/F-03-034Final Report, Steven, Fine, et.al, January 2011, Page 33, Table of Retrofit Cost and Performance.
4) Edison Electric Institute (EEI), Potential Impacts of Environmental Regulations on the U.S. Generation Fleet, ICF International, January 2011, pg. 33.
5) EPA Control Cost Manual, 6th ed., EPA-452-02-001

ATTACHMENT A-1

DRY SORBENT INJECTION COST METHODOLOGY DEVELOPMENT – SARGENT & LUNDY, LLC, AUGUST 2010

ATTACHMENT A-2

SDA FDG COST DEVELOPMENT METHODOLOGY –

SARGENT & LUNDY, LLC, AUGUST 2010

IPM Model – Revisions to Cost and Performance for APC Technologies

SDA FGD Cost Development Methodology

FINAL

August 2010

Project 12301-007

Perrin Quarles Associates, Inc.

Prepared by

Sargent & Lundy LLC

55 East Monroe Street • Chicago, IL 60603 USA • 312-269-2000

IPM Model – Revisions to Cost and Performance for APC Technologies

Wet FGD Cost Development Methodology

FINAL

August 2010

Project 12301-007

Perrin Quarles Associates, Inc.

Prepared by

Sargent & Lundy LLC

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LEGAL NOTICE

This work was funded and reviewed by the U.S. Environmental Protection Agency under the supervision of William A. Stevens, Senior Advisor – Power Technologies. Additional input and review was provided by Dr. Jim Staudt, President of Andover Technology Partners.

Wet FGD Cost Development Methodology – Final

Establishment of Cost Basis

The 2004 to 2006 industry cost estimates for wet FGD units from the "Analysis of MOG and Ladco's FGD and SCR Capacity and Cost Assumptions in the Evaluation of Proposed EGU 1 and EGU 2 Emission Controls" prepared for Midwest Ozone Group (MOG) were compared to the Sargent & Lundy LLC (S&L) in-house database. Agreement of the data was confirmed between the industry estimates and the S&L data.

The MOG and S&L cost data from 2004 to 2006 were converted to 2007 dollars based on the Chemical Engineering Plant Index (CEPI) data. Additional proprietary S&L in-house data from 2007 were included to confirm the index validity.

Cost data from the various sources showed similar trends versus generating capacity. Escalation based on the CEPI was deemed acceptable. All three data sources were combined so as to provide a representative wet FGD cost basis.

The 2004 through 2007 data were escalated to 2009 to represent market conditions.

The least squares curve fit of the data was defined as a "typical" wet FGD retrofit for removal of 98% of the inlet sulfur. It should be noted that the lowest available SO_2 emission guarantees, from the original equipment manufactures of wet FGD systems, are 0.04 lb/MMBtu. The typical wet FGD retrofit was based on:

- Retrofit Difficulty =1 (Average retrofit difficulty) ;
- Gross Heat Rate = 9500 Btu/kWh;
- SO_2 Rate = 3.0 lb/MMBtu;
- Type of Coal = Bituminous;
- Project Execution = Multiple lump sum contracts; and
- Recommended SO_2 emission floor = 98% removal efficiency or 0.06 lb/MMBtu.

Units below 100 MW will typically not install a wet FGD system. Sulfur reductions for the small units would be accomplished by; treating smaller units at a single site with one wet FGD system, switching to a lower sulfur coal, repowering with natural gas, dry sorbent injection, and/or a reduction in operating hours. Capital costs of approximately $750/kW may be used for units below 100 MW under the premise that these will be combined.

Wet FGD Cost Development Methodology – Final

Methodology

Inputs

Several input variables are required in order to predict future retrofit costs. The gross unit size in MW (equivalent acfm) and sulfur content of the fuel are the major variables for the capital estimation. A retrofit factor that equates to difficulty in construction of the system must be defined. The costs herein could increase significantly for congested sites. The gross unit heat rate will factor into the amount of flue gas generated and ultimately the size of the absorber, reagent preparation, waste handling, and balance of plant costs. The SO_2 rate will have the greatest influence on the reagent handling and waste handling facilities. The type of fuel (Bituminous, PRB, or Lignite) will influence the flue gas quantities as a result of the different typical heating values.

The evaluation includes a user selected option for a wastewater treatment facility. The base capital cost includes minor physical and chemical wastewater treatment. However, in the future more extensive wastewater handling may be required. Although an option for wastewater treatment is provided, no logic has been developed to accommodate the additional wastewater treatment costs.

Outputs

Total Project Costs (TPC)

First the base installed costs are calculated for each required module (BM_). The base installed costs include:

- All equipment;
- Installation;
- Buildings;
- Foundations;
- Electrical;
- Minor physical and chemical wastewater treatment (WWT); and
- Average retrofit difficulty.

The modules are:

BMR =	Base absorber island cost
BMF =	Base reagent preparation cost
BMW =	Base waste handling cost
BMB =	Base balance of plan costs including: ID or booster fans, new wet chimney, piping, ductwork, minor WWT, etc.
BMWW =	Base wastewater treatment facility for future use.
BM =	BMR + BMF + BMW + BMB

Wet FGD Cost Development Methodology – Final

The total base installed cost (BM) is then increased by:

- Engineering and construction management costs at 10% of the BM cost;
- Labor adjustment for 6 x 10 hour shift premium, per diem, etc., at 10% of the BM cost; and
- Contractor profit and fees at 10% of the BM cost.

A capital, engineering, and construction cost subtotal (CECC) is established as the sum of the BM and the additional engineering and construction fees.

Additional costs and financing expenditures for the project are computed based on the CECC. Financing and additional project costs include:

- Owner's home office costs (owner's engineering, management, and procurement) at 5% of the CECC; and
- Allowance for Funds Used During Construction (AFUDC) at 10% of the CECC and owner's costs. The AFUDC is based on a three-year engineering and construction cycle.

The total project cost is based on a multiple lump sum contract approach. Should a turnkey engineering procurement construction (EPC) contract be executed, the total project cost could be 10 to 15% higher than what is currently estimated.

Escalation is not included in the estimate. The total project cost (TPC) is the sum of the CECC and the additional costs and financing expenditures. Table 1 contains an example capital cost estimation.

Wet FGD Cost Development Methodology – Final

Table 1. Example Capital Cost Estimate for the Wet FGD System (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Wastewater Treatment		Minor physical/chemical		
Unit Size (Gross)	A	(MW)	500	<--- User Input (Greater than 100 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	3	<--- User Input
Type of Coal	E		Bituminous	<--- User Input
Coal Factor	F		1	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.95	C/10000
Heat Input	H	(Btu/hr)	4.75E+09	A*C*1000

Capital Cost Calculation		Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, minor physical/chemical wastewater treatment and retrofit difficulty			
BMR ($) =	550000*(B)*((F*G)^0.6)*((D/2)^0.02)*(A^0.716)	$ 46,024,000	Base absorber island cost
BMF ($) =	190000*(B)*((D*G)^0.3)*(A^0.716)	$ 22,267,000	Base reagent preparation cost
BMW ($) =	100000*(B)*((D*G)^0.45)*(A^0.716)	$ 13,713,000	Base waste handling cost
BMB ($) =	1010000*(B)*((F*G)^0.4)*(A^0.716)	$ 84,698,000	Base balance of plan costs including: ID or booster fans, new wet chimney, piping, ductwork, minor WWT, etc…
BMWW ($) =		$ -	Base wastewater treatment facility, beyond minor physical/chemical treatment
BM ($) =	BMR + BMF + BMW + BMB + BMWW	$ 166,702,000	Total base cost including retrofit factor
BM ($/KW) =		333	Base cost per kW
Total Project Cost			
A1 = 10% of BM		$ 16,670,000	Engineering and Construction Management costs
A2 = 10% of BM		$ 16,670,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$ 16,670,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$ 216,712,000**	Capital, engineering and construciton cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**433**	Capital, engineering and construciton cost subtotal per kW
B1 = 5% of CECC		$ 10,836,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$ 227,548,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**455**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)		$ 22,755,000	AFUDC (Based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2		**$ 250,303,000**	Total project cost
TPC ($/kW) - Includes Owner's Costs and AFUDC =		**501**	Total project cost per kW

Fixed O&M (FOM)

The fixed operating and maintenance (O&M) cost is a function of the additional operations staff (FOMO), maintenance labor and materials (FOMM), and administrative labor (FOMA) associated with the wet FGD installation. A future fixed O&M cost category is included to account for an extensive wastewater treatment facility. At this time, the wastewater treatment fixed O&M (FOMWW) is not estimated and is included at zero dollars. The FOM is the sum of the FOMO, FOMM, FOMA, and FOMWW.

The following factors and assumptions underlie calculations of the FOM:

- All of the FOM costs were tabulated on a per kilowatt-year (kW yr) basis.
- In general, 12 additional operators are required for a 500 MW or smaller installation. Units larger than 500 MW require a total of 16 additional operators. The FOMO was based on the number of additional operations staff required as a function of generating capacity.
- The fixed maintenance materials and labor is a direct function of the process capital cost (BM).
- The administrative labor is a function of the FOMO and FOMM.

Variable O&M (VOM)

Variable O&M is a function of:

- Reagent use and unit costs;
- Waste production and unit disposal costs;
- Additional power required and unit power cost; and
- Makeup water required and unit water cost.

The following factors and assumptions underlie calculations of the VOM:

- All of the VOM costs were tabulated on a per megawatt-hour (MWh) basis.

- The reagent usage is a function of gross unit size, SO_2 feed rate, and removal efficiency. The estimated reagent usage was based on a sulfur removal efficiency of 98% and a calcium-to-sulfur stoichiometric ratio of 1.03. The basis for the limestone purity was 90% $CaCO_3$ with the balance being inert material.

- The waste generation rate is directly proportional to the reagent usage and is estimated based on 10% moisture in the by-product.

- The additional power required includes increased fan power to account for the added wet FGD pressure drop. This requirement is a function of gross unit size (actual gas flow rate) and sulfur rate.

- The makeup water rate is a function of gross unit size (actual gas flow rate) and sulfur feed rate.

Input options are provided for the user to adjust the variable O&M costs per unit. Average default values are included in the base estimate. The variable O&M costs per unit options are:

- Limestone cost in $/ton;
- Waste disposal costs in $/ton;
- Auxiliary power cost in $/kWh;
- Makeup water costs in $/1000 gallon; and
- Operating labor rate (including all benefits) in $/hr.

The variables that contribute to the overall VOM are:

VOMR =	Variable O&M costs for limestone reagent
VOMW =	Variable O&M costs for waste disposal
VOMP =	Variable O&M costs for additional auxiliary power
VOMM =	Variable O&M costs for makeup water
VOMWW =	Variable O&M costs for wastewater treatment

A future variable O&M cost category is included to account for an extensive wastewater treatment facility. At this time, the wastewater treatment variable O&M (VOMWW) is not estimated and is included at zero dollars.

The total VOM is the sum of VOMR, VOMW, VOMP, VOMM, and VOMWW. Table 2 contains an example O&M cost estimate, while Table 3 is a complete capital and O&M cost estimate worksheet.

Wet FGD Cost Development Methodology – Final

Table 2. Example O&M Cost Estimate for the Wet FGD System (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Wastewater Treatment		Minor physical/chemical		
Unit Size (Gross)	A	(MW)	500	<--- User Input (Greater than 100 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	3	<--- User Input
Type of Coal	E		Bituminuous	<--- User Input
Coal Factor	F		1	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.95	C/10000
Heat Input	H	(Btu/hr)	4.75E+09	A*C*1000
Limestone Rate	K	(ton/hr)	12	17.52*A*D*G/2000
Waste Rate	L	(ton/hr)	23	1.811*K
Aux Power	**M**	**(%)**	**1.59**	(1.05e^(0.155*D))*F*G **Should be used for model input.**
Makeup Water Rate	N	(1000 gph)	38	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	($/ton)	15	
Waste Disposal Cost	Q	($/ton)	30	
Aux Power Cost	R	($/kWh)	0.06	
Makeup Water Cost	S	($/1000)	1	
Operating Labor Rate	T	($/hr)	60	Labor cost including all benefits

Fixed O&M Cost

FOMO ($/kW yr) = (if MW>500 then 16 additional operators else 12 operators)*2080*T/(A*1000)	$	3.00	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	$	5.00	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.15	Fixed O&M additional administrative labor costs
FOMWW ($/kW yr) =	$	-	Fixed O&M costs for wastewater treatment facility
FOM ($/kW yr) = FOMO + FOMM + FOMA + FOMWW	**$**	**8.15**	Total Fixed O&M costs

Variable O&M Cost

VOMR ($/MWh) = K*P/A	$	0.37	Variable O&M costs for limestone reagent
VOMW ($/MWh) = L*Q/A	$	1.36	Variable O&M costs for waste disposal
VOMP ($/MWh) =M*R*10	$	-	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	$	0.08	Variable O&M costs for makeup water
VOMWW ($/MWh) =	$	-	Variable O&M costs for wastewater treatment facility
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM + VOMWW	**$**	**1.81**	

Table 3. Example Complete Cost Estimate for the Wet FGD System (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Wastewater Treatment		Minor physical/chemical		
Unit Size (Gross)	A	(MW)	500	<--- User Input (Greater than 100 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	3	<--- User Input
Type of Coal	E		Bituminuous	<--- User Input
Coal Factor	F		1	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.95	C/10000
Heat Input	H	(Btu/hr)	4.75E+09	A*C*1000
Limestone Rate	K	(ton/hr)	12	17.52*A*D*G/2000
Waste Rate	L	(ton/hr)	23	1.811*K
Aux Power	**M**	**(%)**	**1.59**	(1.05e^(0.155*D))*F*G **Should be used for model input.**
Makeup Water Rate	N	(1000 gph)	38	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	($/ton)	15	
Waste Disposal Cost	Q	($/ton)	30	
Aux Power Cost	R	($/kWh)	0.06	
Makeup Water Cost	S	($/1000)	1	
Operating Labor Rate	T	($/hr)	60	Labor cost including all benefits

Capital Cost Calculation		Example		Comments
Includes - Equipment, installation, buildings, foundations, electrical, minor physical/chemical wastewater treatment and retrofit difficulty				
BMR ($) =	550000*(B)*((F*G)^0.6)*((D/2)^0.02)*(A^0.716)	$	46,024,000	Base absorber island cost
BMF ($) =	190000*(B)*((D*G)^0.3)*(A^0.716)	$	22,267,000	Base reagent preparation cost
BMW ($) =	100000*(B)*((D*G)^0.45)*(A^0.716)	$	13,713,000	Base waste handling cost
BMB ($) =	1010000*(B)*((F*G)^0.4)*(A^0.716)	$	84,698,000	Base balance of plan costs including: ID or booster fans, new wet chimney, piping, ductwork, minor WWT, etc…
BMWW ($) =		$	-	Base wastewater treatment facility, beyond minor physical/chemical treatment
BM ($) =	BMR + BMF + BMW + BMB + BMWW	$	166,702,000	Total base cost including retrofit factor
BM ($/KW) =			333	Base cost per kW
Total Project Cost				
A1 = 10% of BM		$	16,670,000	Engineering and Construction Management costs
A2 = 10% of BM		$	16,670,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$	16,670,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$**	**216,712,000**	Capital, engineering and construciton cost subtotal
CECC ($/kW) - Excludes Owner's Costs =			**433**	Capital, engineering and construciton cost subtotal per kW
B1 = 5% of CECC		$	10,836,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$**	**227,548,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =			**455**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)		$	22,755,000	AFUDC (Based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2		**$**	**250,303,000**	Total project cost
TPC ($/kW) - Includes Owner's Costs and AFUDC =			**501**	Total project cost per kW

Wet FGD Cost Development Methodology – Final

Variable	Designation	Units	Value	Calculation
Wastewater Treatment		Minor physical/chemical		
Unit Size (Gross)	A	(MW)	500	<--- User Input (Greater than 100 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	3	<--- User Input
Type of Coal	E		Bituminuous	<--- User Input
Coal Factor	F		1	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.95	C/10000
Heat Input	H	(Btu/hr)	4.75E+09	A*C*1000
Limestone Rate	K	(ton/hr)	12	17.52*A*D*G/2000
Waste Rate	L	(ton/hr)	23	1.811*K
Aux Power	**M**	**(%)**	**1.59**	(1.05e^(0.155*D))*F*G **Should be used for model input.**
Makeup Water Rate	N	(1000 gph)	38	(1.674*D+74.68)*A*F*G/1000
Limestone Cost	P	($/ton)	15	
Waste Disposal Cost	Q	($/ton)	30	
Aux Power Cost	R	($/kWh)	0.06	
Makeup Water Cost	S	($/1000)	1	
Operating Labor Rate	T	($/hr)	60	Labor cost including all benefits

Fixed O&M Cost

FOMO ($/kW yr) = (if MW>500 then 16 additional operators else 12 operators)*2080*T/(A*1000)	$	3.00	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	$	5.00	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.15	Fixed O&M additional administrative labor costs
FOMWW ($/kW yr) =	$	-	Fixed O&M costs for wastewater treatment facility
FOM ($/kW yr) = FOMO + FOMM + FOMA + FOMWW	**$**	**8.15**	Total Fixed O&M costs

Variable O&M Cost

VOMR ($/MWh) = K*P/A	$	0.37	Variable O&M costs for limestone reagent
VOMW ($/MWh) = L*Q/A	$	1.36	Variable O&M costs for waste disposal
VOMP ($/MWh) =M*R*10	$	-	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	$	0.08	Variable O&M costs for makeup water
VOMWW ($/MWh) =	$	-	Variable O&M costs for wastewater treatment facility
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM + VOMWW	**$**	**1.81**	

LEGAL NOTICE

This work was funded and reviewed by the U.S. Environmental Protection Agency under the supervision of William A. Stevens, Senior Advisor – Power Technologies. Additional input and review was provided by Dr. Jim Staudt, President of Andover Technology Partners.

SDA FGD Cost Development Methodology – Final

Establishment of Cost Basis

Cost data for the SDA FGD systems was more limited than that for the wet FGD systems. A similar trend with generating capacity is generally seen between the wet and SDA system. The same generating capacity relationship was used for the wet and SDA cost estimation.

A least squares curve fit of proprietary in-house cost data was defined as a "typical" SDA FGD retrofit for removal of 95% of the inlet sulfur. It should be noted that the lowest available SO_2 emission guarantees, from the original equipment manufactures of SDA FGD systems, are 0.06 lb/MMBtu. The typical SDA FGD retrofit was based on:

- Retrofit Difficulty = 1 (Average retrofit difficulty);
- Gross Heat Rate = 9800 Btu/kWh;
- SO_2 Rate = 2.0 lb/MMBtu;
- Type of Coal = PRB; and
- Project Execution = Multiple lump sum contracts; and
- Recommended SO_2 emission floor = 0.08 lb/MMBtu.

Units below 50 MW will typically not install an SDA FGD system. Sulfur reductions for the small units would be accomplished by; treating smaller units at a single site with one SDA FGD system, switching to a lower sulfur coal, repowering with natural gas, dry sorbent injection, and/or a reduction in operating hours. Capital costs of approximately $800/kW may be used for units below 50 MW under the premise that these will be combined.

Based on the typical SDA FGD performance, the technology should not be applied to fuels with more than 3 lb SO_2/MMBtu and the cost estimator should be limited to fuels with less than 3 lb SO_2/MMBtu.

An alternate dry technology, circulating dry scrubber (CDS), can meet removals of 98% or greater over a large range of inlet sulfur concentrations. It should be noted that the lowest SO_2 emission guarantees for a CDS FGD system are 0.04 lb/MMBtu.

Methodology

Inputs

Several input variables are required in order to predict future retrofit costs. The gross unit size in MW (equivalent acfm) and sulfur content of the fuel are the major variables for the capital estimation. A retrofit factor that equates to difficulty in construction of the system must be defined. The costs herein could increase significantly for congested sites. The unit gross heat rate will factor into the amount of flue gas generated and ultimately the size of the absorber, reagent preparation, waste handling, and balance of plant costs. The SO_2 rate will have the greatest influence on the reagent handling and waste handling facilities. The type of fuel (Bituminous, PRB, or Lignite) will influence the flue gas quantities as a result of the different typical heating values.

Outputs

Total Project Costs (TPC)

First the base installed costs are calculated for each required module (BM_). The base installed costs include:

- All equipment;
- Installation;
- Buildings;
- Foundations;
- Electrical; and
- Average retrofit difficulty.

The modules are:

BMR =	Base absorber island cost
BMF =	Base reagent preparation and waste recycle/handling cost
BMB =	Base balance of plan costs including: ID or booster fans, piping, ductwork, electrical, etc.
BM =	BMR + BMF + BMB

The total base installed cost (BM) is then increased by:

- Engineering and construction management costs at 10% of the BM cost;
- Labor adjustment for 6 x 10 hour shift premium, per diem, etc., at 10% of the BM cost; and
- Contractor profit and fees at 10% of the BM cost.

A capital, engineering, and construction cost subtotal (CECC) is established as the sum of the BM and the additional engineering and construction fees.

Additional costs and financing expenditures for the project are computed based on the CECC. Financing and additional project costs include:

- Owner's home office costs (owner's engineering, management, and procurement) at 5% of the CECC; and
- Allowance for Funds Used During Construction (AFUDC) at 10% of the CECC and owner's costs. The AFUDC is based on a three-year engineering and construction cycle.

SDA FGD Cost Development Methodology – Final

The total project cost is based on a multiple lump sum contract approach. Should a turnkey engineering procurement construction (EPC) contract be executed, the total project cost could be 10 to 15% higher than what is currently estimated.

Escalation is not included in the estimate. The total project cost (TPC) is the sum of the CECC and the additional costs and financing expenditures. Table 1 contains an example capital cost estimation.

SDA FGD Cost Development Methodology – Final

Table 1. Example Capital Cost Estimate for the SDA FGD System (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	300	<--- User Input (Greater than 50 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9800	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		PRB	<--- User Input
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.98	C/10000
Heat Input	H	(Btu/hr)	2.94E+09	A*C*1000

Capital Cost Calculation		**Example**		**Comments**
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty				
BMR ($) =	if(A>600 then (A*92000) else 566000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01	$	33,953,000	Base module absorber island cost
BMF ($) =	if(A>600 then (A*48700) else 300000*(A^0.716))*B*(D*G)^0.2	$	20,379,000	Base module reagent preparation and waste recycle/handling cost
BMB ($) =	if(A>600 then (A*129900) else 799000*(A^0.716))*B*(F*G)^0.4	$	47,988,000	Base module balance of plan costs including: ID or booster fans, piping, ductwork, electrical, etc…
BM ($) =	BMR + BMF + BMW + BMB	$	102,320,000	Total Base module cost including retrofit factor
BM ($/KW) =			341	Base module cost per kW
Total Project Cost				
A1 = 10% of BM		$	10,232,000	Engineering and Construction Management costs
A2 = 10% of BM		$	10,232,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$	10,232,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$**	**133,016,000**	Capital, engineering and construciton cost subtotal
CECC ($/kW) - Excludes Owner's Costs =			**443**	Capital, engineering and construciton cost subtotal per kW
B1 = 5% of CECC		$	6,651,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$**	**139,667,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =			**466**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)		$	13,967,000	AFUDC (Based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2		**$**	**153,634,000**	Total project cost
TPC ($/kW) - Includes Owner's Costs and AFUDC =			**512**	Total project cost per kW

SDA FGD Cost Development Methodology – Final

Fixed O&M (FOM)

The fixed operating and maintenance (O&M) cost is a function of the additional operations staff (FOMO), maintenance labor and materials (FOMM), and administrative labor (FOMA) associated with the SDA FGD installation. The FOM is the sum of the FOMO, FOMM, and FOMA.

The following factors and assumptions underlie calculations of the FOM:

- All of the FOM costs were tabulated on a per kilowatt-year (kW yr) basis.
- In general, 8 additional operators are required for a SDA FGD system. The FOMO was based on the number of additional operations staff required.
- The fixed maintenance materials and labor is a direct function of the process capital cost (BM).
- The administrative labor is a function of the FOMO and FOMM.

Variable O&M (VOM)

Variable O&M is a function of:

- Reagent use and unit costs;
- Waste production and unit disposal costs;
- Additional power required and unit power cost; and
- Makeup water required and unit water cost.

The following factors and assumptions underlie calculations of the VOM:

- All of the VOM costs were tabulated on a per megawatt-hour (MWh) basis.
- The reagent usage is a function of gross unit size, SO_2 feed rate, and removal efficiency. The estimated reagent usage was based on a sulfur removal efficiency of 95% with a flue gas temperature into the SDA FGD of 300°F and an adiabatic approach to saturation of 30°F. The calcium-to-sulfur stoichiometric ratio varies based on inlet sulfur. The variation in stoichiometric ratio was accounted for in the estimation. The economic estimation is only valid up to 3 lb SO_2/MMBtu inlet. The basis for the lime purity was 90% CaO with the balance being inert material.

- The waste generation rate is a function of inlet sulfur and calcium to sulfur stoichiometry. Both variables are accounted for in the waste generation estimation. The waste disposal rate is based on 10% moisture in the by-product.

- The additional power required includes increased fan power to account for the added SDA FGD pressure drop. This requirement is a function of gross unit size (actual gas flow rate) and sulfur rate.

- The makeup water rate is a function of gross unit size (actual gas flow rate) and sulfur feed rate.

Input options are provided for the user to adjust the variable O&M costs per unit. Average default values are included in the base estimate. The variable O&M costs per unit options are:

- Limestone cost in $/ton;
- Waste disposal costs in $/ton;
- Auxiliary power cost in $/kWh;
- Makeup water costs in $/1000 gallon; and
- Operating labor rate (including all benefits) in $/hr.

The variables that contribute to the overall VOM are:

VOMR = Variable O&M costs for lime reagent

VOMW = Variable O&M costs for waste disposal

VOMP = Variable O&M costs for additional auxiliary power

VOMM = Variable O&M costs for makeup water

The total VOM is the sum of VOMR, VOMW, VOMP, and VOMM. Table 2 contains an example O&M cost estimate, while Table 3 is a complete capital and O&M cost estimate worksheet.

Table 2. Example O&M Cost Estimate for the SDA FGD System (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	300	<--- User Input (Greater than 50 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9800	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		PRB	<--- User Input
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.98	C/10000
Heat Input	H	(Btu/hr)	2.94E+09	A*C*1000
Lime Rate	K	(ton/hr)	4	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Waste Rate	L	(ton/hr)	10	(0.8016*(D^2)+31.1917*D)*A*G/2000
Aux Power	**M**	**(%)**	**1.35**	(0.000547*D^2+0.00649*D+1.3)*F*G **Should be used for model input.**
Makeup Water Rate	N	(1000 gph)	17	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	95	
Waste Disposal Cost	Q	($/ton)	30	
Aux Power Cost	R	($/kWh)	0.06	
Makeup Water Cost	S	($/1000)	1	
Operating Labor Rate	T	($/hr)	60	Labor cost including all benefits

Fixed O&M Cost

FOMO ($/kW yr) = (8 additional operators)*2080*T/(A*1000)	$	3.33	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	$	5.12	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.16	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**8.61**	Total Fixed O&M costs

Variable O&M Cost

VOMR ($/MWh) = K*P/A	$	1.37	Variable O&M costs for lime reagent
VOMW ($/MWh) = L*Q/A	$	0.96	Variable O&M costs for waste disposal
VOMP ($/MWh) =M*R*10	$	-	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	$	0.06	Variable O&M costs for makeup water
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**$**	**2.40**	

Table 3. Example Complete Cost Estimate for the SDA FGD System (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	300	<--- User Input (Greater than 50 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9800	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		PRB	<--- User Input
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.98	C/10000
Heat Input	H	(Btu/hr)	2.94E+09	A*C*1000
Lime Rate	K	(ton/hr)	4	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Waste Rate	L	(ton/hr)	10	(0.8016*(D^2)+31.1917*D)*A*G/2000
Aux Power	**M**	**(%)**	**1.35**	(0.000547*D^2+0.00649*D+1.3)*F*G **Should be used for model input.**
Makeup Water Rate	N	(1000 gph)	17	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	95	
Waste Disposal Cost	Q	($/ton)	30	
Aux Power Cost	R	($/kWh)	0.06	
Makeup Water Cost	S	($/1000)	1	
Operating Labor Rate	T	($/hr)	60	Labor cost including all benefits

Capital Cost Calculation		Example		Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty				
BMR ($) =	if(A>600 then (A*92000) else 566000*(A^0.716))*B*(F*G)^0.6*(D/4)^0.01	$	33,953,000	Base module absorber island cost
BMF ($) =	if(A>600 then (A*48700) else 300000*(A^0.716))*B*(D*G)^0.2	$	20,379,000	Base module reagent preparation and waste recycle/handling cost
BMB ($) =	if(A>600 then (A*129900) else 799000*(A^0.716))*B*(F*G)^0.4	$	47,988,000	Base module balance of plan costs including: ID or booster fans, piping, ductwork, electrical, etc…
BM ($) =	BMR + BMF + BMW + BMB	$	102,320,000	Total Base module cost including retrofit factor
BM ($/KW) =			341	Base module cost per kW
Total Project Cost				
A1 = 10% of BM		$	10,232,000	Engineering and Construction Management costs
A2 = 10% of BM		$	10,232,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$	10,232,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$**	**133,016,000**	Capital, engineering and construciton cost subtotal
CECC ($/kW) - Excludes Owner's Costs =			**443**	Capital, engineering and construciton cost subtotal per kW
B1 = 5% of CECC		$	6,651,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$**	**139,667,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =			**466**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)		$	13,967,000	AFUDC (Based on a 3 year engineering and construction cycle)
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2		**$**	**153,634,000**	Total project cost
TPC ($/kW) - Includes Owner's Costs and AFUDC =			**512**	Total project cost per kW

SDA FGD Cost Development Methodology – Final

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	300	<--- User Input (Greater than 50 MW)
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9800	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input (SDA FGD Estimation only valid up to 3 lb/MMBtu SO2 Rate)
Type of Coal	E		PRB	<--- User Input
Coal Factor	F		1.05	Bit=1, PRB=1.05, Lig=1.07
Heat Rate Factor	G		0.98	C/10000
Heat Input	H	(Btu/hr)	2.94E+09	A*C*1000
Lime Rate	K	(ton/hr)	4	(0.6702*(D^2)+13.42*D)*A*G/2000 (Based on 95% SO2 removal)
Waste Rate	L	(ton/hr)	10	(0.8016*(D^2)+31.1917*D)*A*G/2000
Aux Power	**M**	**(%)**	**1.35**	(0.000547*D^2+0.00649*D+1.3)*F*G **Should be used for model input.**
Makeup Water Rate	N	(1000 gph)	17	(0.04898*(D^2)+0.5925*D+55.11)*A*F*G/1000
Lime Cost	P	($/ton)	95	
Waste Disposal Cost	Q	($/ton)	30	
Aux Power Cost	R	($/kWh)	0.06	
Makeup Water Cost	S	($/1000)	1	
Operating Labor Rate	T	($/hr)	60	Labor cost including all benefits

Fixed O&M Cost

FOMO ($/kW yr) = (8 additional operators)*2080*T/(A*1000)	$	3.33	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	$	5.12	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.16	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**8.61**	Total Fixed O&M costs

Variable O&M Cost

VOMR ($/MWh) = K*P/A	$	1.37	Variable O&M costs for lime reagent
VOMW ($/MWh) = L*Q/A	$	0.96	Variable O&M costs for waste disposal
VOMP ($/MWh) =M*R*10	$	-	Variable O&M costs for additional auxiliary power required including additional fan power (Refer to Aux Power % above)
VOMM ($/MWh) = N*S/A	$	0.06	Variable O&M costs for makeup water
VOM ($/MWh) = VOMR + VOMW + VOMP + VOMM	**$**	**2.40**	

IPM Model – Revisions to Cost and Performance for APC Technologies

Dry Sorbent Injection Cost Development Methodology

FINAL

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Project 12301-007

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LEGAL NOTICE

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Dry Sorbent Injection Cost Development Methodology – Final

Technology Description

Dry sorbent injection (DSI) is a viable technology for moderate SO_2 reduction on coal fired boilers. Demonstrations and recent utility testing have shown SO_2 removals greater than 80% for systems using sodium based sorbents. The most common sodium based sorbent is Trona.

The level of removal for Trona can vary from 0 to 90% depending on the Normalized Stoichiometric Ratio (NSR) and particulate capture device. NSR is defined as:

$$\frac{\text{(moles of Na injected)}}{\text{(moles of SO}_2\text{ in flue gas)}} \Big/ \text{(theoretical moles of Na required)}$$

The target removal efficiency is a requirement from the utility and is independent of unit size. The costs for a DSI system are primarily dependant on sorbent feed rate which is a function of NSR and SO_2 mass feed rate per hour. Therefore, the cost estimation was based on sorbent feed rate and not on unit size.

The sorbent solids can be collected in either an ESP or a baghouse. Baghouses generally achieve greater SO_2 removal efficiencies than ESPs by virtue of the filter cake on the bags, which allows for longer reaction time between the sorbent solids and the flue gas. For a given removal efficiency with Trona, the NSR is reduced when a baghouse is used for particulate capture.

The dry sorbent capture ability is also a function of particle surface area. To increase the particle surface area, the sorbent must be heated. Heating the solids produces micropores on the particle surface which greatly improve the sulfur capture ability. For Trona, the sorbent should be injected into flue gas above 275°F to maximize the micropore structure. However, if the flue gas is too hot (greater than 800°F), the solids may sinter and surface area is reduced.

Another way to increase surface area is to mechanically reduce the particle size by grinding the sorbent. Typical Trona is delivered unmilled. The ore is ground such that the unmilled product has an average size around 30 μm. Commercial testing has shown that the reactivity of the Trona can be increased when the sorbent is ground to less than 30 μm. In the cost estimating methodology, the Trona is always delivered in the unmilled state. To mill the Trona, in-line mills are continuously used during the Trona injection process. Therefore, the delivered cost of the Trona will not change, only the reactivity and usage changes as the Trona is milled.

Ultimately, the NSR required for a given removal is a function of Trona particle size and particulate capture equipment. Either as delivered Trona (around 30 µm average size) or in-line milled Trona (around 15 µm average size) can be chosen for injection in the cost program. The average Trona particle size and the type of particulate removal both contribute to the predicted Trona feed rate.

Establishment of Cost Basis

For the wet or SDA FGD systems, the sulfur removal is generally specified at the maximum achievable level. With those systems, costs are primarily a function of plant size and sulfur rate. However, the DSI systems are quite different. The major cost for the DSI system is the sorbent itself. The sorbent feed rate is a function of sulfur rate, particulate collection device, and removal efficiency. To account for all of the variables, the capital cost was established based on a sorbent feed rate. The sorbent feed rate is calculated from user input variables. Cost data for several DSI systems was reviewed and a relationship was developed for the capital costs of the system on a sorbent feed rate basis.

Methodology

Inputs

Several input variables are required in order to predict future retrofit costs. The sulfur feed rate and NSR are the major variables for the cost estimate. The NSR is a function of:

- Removal efficiency;
- Trona particle size; and
- Particulate capture device.

A retrofit factor that equates to difficulty in construction of the system must be defined. The gross unit size and gross heat rate will factor into the amount of sulfur generated.

Based on commercial testing, removal efficiencies with DSI are limited by the particulate capture device employed. When the sorbent is captured in an ESP, a 40 to 50% SO_2 removal is typically achieved without an increase in particulate emissions. A higher efficiency (70 – 75%) is generally achieved with a baghouse. The DSI technology should not be applied to fuels with a sulfur content of greater than 2 lb SO_2/MMBtu.

Dry Sorbent Injection Cost Development Methodology – Final

The equations provided in the cost methodology spreadsheet allow the user to input the required removal efficiency, within the limits of the technology. To simplify the correlation, the removal with an ESP should be set at 50% and 70% with a baghouse. The simplified sorbent NSR would then be:

For an ESP at the target 50% removal:
Unmilled Trona NSR = 2.85
Milled Trona NSR = 1.40

For a baghouse at the target 70% removal:
Unmilled Trona NSR = 2.00
Milled Trona NSR = 1.55

The correlation could be further simplified by assuming that only milled Trona is used. The current trend in the industry is to use in-line milling of the Trona to improve the utilization. For a minor increase in capital, the milling can greatly reduce the variable operating expenses. It is recommended that only milled Trona be considered in the simplified model.

Outputs

Total Project Costs (TPC)

First the base installed cost for the complete DSI system is calculated (BM). The base installed cost includes:

- All equipment;
- Installation;
- Buildings;
- Foundations;
- Electrical; and
- Average retrofit difficulty.

The base module cost is adjusted by the selection of in-line milling equipment. The base installed cost is then increased by:

- Engineering and construction management costs at 5% of the BM cost;
- Labor adjustment for 6 x 10 hour shift premium, per diem, etc., at 5% of the BM cost; and
- Contractor profit and fees at 5% of the BM cost.

A capital, engineering, and construction cost subtotal (CECC) is established as the sum of the BM and the additional engineering and construction fees.

Additional costs and financing expenditures for the project are computed based on the CECC. Financing and additional project costs include:

- Owner's home office costs (owner's engineering, management, and procurement) at 5% of the CECC; and
- Allowance for Funds Used During Construction (AFUDC) at 0% of the CECC and owner's costs as these projects are expected to be completed in less than a year.

The total project cost is based on a multiple lump sum contract approach. Should a turnkey engineering procurement construction (EPC) contract be executed, the total project cost could be 10 to 15% higher than what is currently estimated.

Escalation is not included in the estimate. The total project cost (TPC) is the sum of the CECC and the additional costs and financing expenditures.

Fixed O&M (FOM)

The fixed operating and maintenance (O&M) cost is a function of the additional operations staff (FOMO), maintenance labor and materials (FOMM), and administrative labor (FOMA) associated with the DSI installation. The FOM is the sum of the FOMO, FOMM, and FOMA.

The following factors and assumptions underlie calculations of the FOM:

- All of the FOM costs were tabulated on a per kilowatt-year (kW-yr) basis.

- In general, 2 additional operators are required for a DSI system. The FOMO was based on the number of additional operations staff required.

- The fixed maintenance materials and labor is a direct function of the process capital cost (BM).

- The administrative labor is a function of the FOMO and FOMM.

Dry Sorbent Injection Cost Development Methodology – Final

Variable O&M (VOM)

Variable O&M is a function of:

- Reagent use and unit costs;
- Waste production and unit disposal costs; and
- Additional power required and unit power cost.

The following factors and assumptions underlie calculations of the VOM:

- All of the VOM costs were tabulated on a per megawatt-hour (MWh) basis.

- The reagent usage is a function of NSR and SO_2 feed rate. The gross unit size and gross heat rate factor multiplied by the SO_2 rate determine the SO_2 feed rate. The estimated NSR is a function of removal efficiency required. The basis for the total reagent rate is a Trona purity of 98%.

- The waste generation rate is a function of the Trona feed rate and is adjusted for the excess sorbent fed. The waste generation rate is based on reaction products of Na_2SO_4 and unreacted dry sorbent as Na_2CO_3.

- With the addition of a sodium sorbent, any fly ash produced must be landfilled. Typical ash contents for each fuel are used to calculate a total fly ash production rate. The fly ash production is added to the sorbent waste to account for a total waste stream in the O&M analysis.

- The additional power required includes air blowers for the injection system, drying equipment for the transport air, and in-line Trona milling equipment as needed.

Input options are provided for the user to adjust the variable O&M costs per unit. Average default values are included in the base estimate. The variable O&M costs per unit options are:

- Trona cost in $/ton;
- Waste disposal costs in $/ton;
- Auxiliary power cost in $/kWh;
- Operating labor rate (including all benefits) in $/hr.

Dry Sorbent Injection Cost Development Methodology – Final

The variables that contribute to the overall VOM are:

VOMR = Variable O&M costs for trona reagent

VOMW = Variable O&M costs for waste disposal

VOMP = Variable O&M costs for additional auxiliary power

The total VOM is the sum of VOMR, VOMW, and VOMP. Table 1 contains an example of the complete capital and O&M cost estimate worksheet.

Dry Sorbent Injection Cost Development Methodology – Final

Table 1. Example Complete Cost Estimate for a DSI System (Costs are all based on 2009 dollars)

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input
Type of Coal	E		Bituminuous	<--- User Input
Particulate Capture	F		ESP	<--- User Input
Milled Trona	G		TRUE	Based on in-line milling equipment
Removal Target	H		50	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with an BGH = 80% Milled Trona with an BGH = 90%
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000
NSR	K		1.43	Unmilled Trona with an ESP = if(H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if(H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with an BGH = if(H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with an BGH = if(H<40,0.0160*H,0.208e^(0.0281*H))
Trona Feed Rate	M	(ton/hr)	16.33	(1.2011x10^-06)*K*A*C*D
Sorbent Waste Rate	N	(ton/hr)	11.07	(0.7035-0.00073696*H/K)*M Based on a final reaction product of Na2SO4 and unreacted dry sorbent as Na2CO3.
Fly Ash Waste Rate	P	(ton/hr)	20.73	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2; HHV = 7200
Aux Power	**Q**	**(%)**	**0.65**	=if Milled Trona M*20/A else M*18/A **Should be used for model input.**
Trona Cost	R	($/ton)	145	
Waste Disposal Cost	S	($/ton)	50	
Aux Power Cost	T	($/kWh)	0.06	
Operating Labor Rate	U	($/hr)	60	Labor cost including all benefits

Capital Cost Calculation	Example		Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty			
BM ($) = Unmilled Trona if(M>25 then (682,000*B*M) else 6,833,000*B*(M^0.284) Milled Trona if(M>25 then (750,000*B*M) else 7,516,000*B*(M^0.284)	$	16,615,000	Base DSI module includes all equipment from unloading to injection
BM ($/KW) =		33	Base module cost per kW
Total Project Cost			
A1 = 5% of BM	$	831,000	Engineering and Construction Management costs
A2 = 5% of BM	$	831,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 5% of BM	$	831,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3	**$**	**19,108,000**	Capital, engineering and construciton cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**38**	Capital, engineering and construciton cost subtotal per kW
B1 = 5% of CECC	$	955,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1	**$**	**20,063,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**40**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)	$	-	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1 + B2	**$**	**20,063,000**	Total project cost
TPC ($/kW) =		**40**	Total project cost per kW

Dry Sorbent Injection Cost Development Methodology – Final

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	9500	<--- User Input
SO2 Rate	D	(lb/MMBtu)	2	<--- User Input
Type of Coal	E		Bituminous	<--- User Input
Particulate Capture	F		ESP	<--- User Input
Milled Trona	G		TRUE	Based on in-line milling equipment
Removal Target	H		50	Maximum Removal Targets: Unmilled Trona with an ESP = 65% Milled Trona with an ESP = 80% Unmilled Trona with an BGH = 80% Milled Trona with an BGH = 90%
Heat Input	J	(Btu/hr)	4.75E+09	A*C*1000
NSR	K		1.43	Unmilled Trona with an ESP = if(H<40,0.0350*H,0.352e^(0.0345*H)) Milled Trona with an ESP = if(H<40,0.0270*H,0.353e^(0.0280*H)) Unmilled Trona with an BGH = if(H<40,0.0215*H,0.295e^(0.0267*H)) Milled Trona with an BGH = if(H<40,0.0160*H,0.208e^(0.0281*H))
Trona Feed Rate	M	(ton/hr)	16.33	(1.2011x10^-06)*K*A*C*D
Sorbent Waste Rate	N	(ton/hr)	11.07	(0.7035-0.00073696*H/K)*M Based on a final reaction product of Na2SO4 and unreacted dry sorbent as Na2CO3.
Fly Ash Waste Rate	P	(ton/hr)	20.73	(A*C)*Ash in Coal*(1-Boiler Ash Removal)/(2*HHV) For Bituminous Coal: Ash in Coal = 0.12; Boiler Ash Removal = 0.2; HHV = 11000 For PRB Coal: Ash in Coal = 0.06; Boiler Ash Removal = 0.2; HHV = 8400 For Lignite Coal: Ash in Coal = 0.08; Boiler Ash Removal = 0.2; HHV = 7200
Aux Power	**Q**	**(%)**	**0.65**	=if Milled Trona M*20/A else M*18/A **Should be used for model input.**
Trona Cost	R	($/ton)	145	
Waste Disposal Cost	S	($/ton)	50	
Aux Power Cost	T	($/kWh)	0.06	
Operating Labor Rate	U	($/hr)	60	Labor cost including all benefits

Fixed O&M Cost

FOMO ($/kW yr) = (1 additional operator)*2080*U/(A*1000)	$	0.25	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.01/(B*A*1000)	$	0.33	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.01	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.59**	Total Fixed O&M costs

Variable O&M Cost

VOMR ($/MWh) = M*R/A	$	4.74	Variable O&M costs for trona reagent
VOMW ($/MWh) = (N+P)*S/A	$	3.18	Variable O&M costs for waste disposal that includes both the sorbent and the fly ash waste
VOMP ($/MWh) =Q*T*10	$	-	Variable O&M costs for additional auxiliary power required (Refer to Aux Power % above)
VOM ($/MWh) = VOMR + VOMW + VOMP	**$**	**7.92**	

ATTACHMENT A-3

WET FGD COST DEVELOPMENT METHODOLOGY –

SARGENT & LUNDY, LLC, AUGUST 2010

TABLE 4-1 EMPIRICAL EQUATIONS USED IN THE IPM MODEL CONTROL COSTING ANALYSES

The written descriptions below are presented to represent the S&L empirical equations used in their cost analysis methodology. The note numbers are found on worksheets in this section.

DRY SORBENT INJECTION

(Notes)

1 NSR or "K" = 0.353 x EXP(0.028 x H) {assumes ESP control and milled trona}

2 Trona feed rate or "M"= 1.2011 x 10^{-6} x K x A x C x D, {units are in tons/hour}

3 Sorbent waste rate or "N" = (0.7035 - 0.00073696 x H / K) x M {units are in tons/hour}

4 Fly ash waste rate or "P" = (A x C) x 0.06 ash in PRB coal x (1 - 0.2) / (2 x 8,400 Btu/lb)

5 Basic module cost = $7,516000 x B x $(M)^{0.284}$

6 Auxiliary power to run equipment = M x 20 / A {percent of gross plant power}

SPRAY DRYER ABSORBER

(Notes)

1 Lime rate = (0.6702 x $(D)^2$ + 13.42 x D) x A x C /10,000 / 2000 {units are in tons per hour}

2 Waste rate = (0.8016 x $(D)^2$ + 31.1917 x D) x A x C /10,000/2000 {units are in tons per hour}

3 Water rate = (0.04898 x $(D)^2$ +0.5925 x D + 55.11) x A X 1.05 x C/10,000/1000 {units are in 10^3 gals/hr}

4 Basic spray dryer equipment = $566,000 x $A^{0.716}$ x B x $(1.18)^{0.6}$ x $(D/4)^{0.01}$

5 Reagent prep equip cost = $300,000 x $A^{0.716}$ x B x $(D \text{ x } G)^{0.2}$

6 Balance of SDA equipment = $799,000 x $A^{0.716}$ x B x $(F \text{ x } G)^{0.6}$

7 Aux power to run equipment = (0.000547 x D^2 + 0.00649 x D + 1.3) x 1.18

WET FLUE GAS DESULFURIZATION

(Notes)

1 Limestone rate or "K" = 17.52 x A x D x G /2000 {units are in tons per hour}

2 Waste rate = limestone rate x 1.811 {units are in tons per hour}

3 Water rate = (1.674 x D + 74.68) x A x F x G / 1000 {units are in 10^3 gals/hr)

4 Basic absorber cost = $550,000 x $A^{0.716}$ x B x $(F \text{ X } G)^{0.6}$ x $(D/2)^{0.02}$

5 Reagent prep equip cost = $190,000 x $A^{0.716}$ x $(D \text{ x } G)^{0.3}$

6 Basic waste handling cost = $100,000 x $A^{0.716}$ x B x $(D \text{ x } G)^{0.45}$

7 Balance of plant cost = $1,010,000 x B x $A^{0.716}$ x $(F \text{ X } G)^{0.4}$

8 Aux power to run equipment = 1.05e^(0.155 x D) x F x G

Table 4-2a

DRY SORBENT INJECTION COSTING DEVELOPMENT

DESIGN CASE FOR CAPITAL COST

Variable	Designation	Units	Value	Equation/Input[1]
DRY INJECTION CAPITAL COST DESIGN BASIS FOR 2 LBS/MMBTU SO_2				
Unit Capacity (Gross)	A	(MW)	162	Input
Retrofit Factor	B		2	Difficulty of Retrofit
Gross heat rate	C	Btu/KW-hr	11,982	Input
SO_2 Emiss Rate	D	lbs/MMBtu	2	Uncontrolled
Type of Coal	E	PRB		Input
Particulate Control	F	ESP		Input
Trona Milling	G	Yes		Input
Removal Target	H		70	
Heat input	J	MM Btu/hr	1941.1	A X C x 1000
NSR	K		2.51	See Note DSI Note 1
Trona Feed rate	M	(tons/hr)	11.69	See Note DSI Note 2
Sorbent Waste Rate	N	(tons/hr)	7.98	See Note DSI Note 3
Fly Ash Waste Rate	P	(tons/hr)	5.55	See Note DSI Note 4
Aux Power	Q	(%)	1.44	See Note DSI Note 6
Trona Cost	R	($/ton)	150	
Waste Disposal Cost	S	($/ton)	50	
Aux Power Cost	T	($/kWhr)	0.06	
Operating Labor Rate	U	($/hr)	60	
CAPITAL EQUIPMENT COSTS				
Capital Cost	BM	($)	$30,215,380	Base DSI Module See note 5
Engineering, Construction Mgmt		5%	$1,510,769	
Construction Labor		5%	$1,510,769	
Contractor Profit and Fees		5%	$1,510,769	
Owners Cost		5%	$1,737,384	
Total Project Cost			$36,485,071	
			225	$/kW
OPERATING AND MAINTENANCE COSTS				
Fixed Operator Cost			$124,800	2,080 hrs- one operator
Maintenance Material			$302,154	1% of BM Capital Cost
Admin Labor Cost			$7,370	
Trona Cost			$1,752.82	Trona cost in $/hr
Waste Disposal Cost			$676.31	Total Waste Cost in $/hr

Notes:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-Dry Sorbent Injection Cost Development Methodology-FINAL", August 2010 Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

Table 4-2b
DRY SORBENT INJECTION COSTING DEVELOPMENT
30-DAY ROLLING AVERAGE OPERATIONAL PARAMETERS

Variable	Designation	Units	Value	Equation/Input[1]
DRY INJECTION OPERATING VARIABLES - ACTUAL OPERATION AT 0.46 LBS/MMBTU SO_2				
Unit Capacity (Gross)	A	(MW)	162	Input
Retrofit Factor	B		2	Difficulty of Retrofit
Gross heat rate	C	Btu/KW-hr	11,982	Input
SO_2 Emiss Rate	D	lbs/MMBtu	0.46	Uncontrolled
Type of Coal	E	PRB		Input
Particulate Control	F	ESP		Input
Trona Milling	G	Yes		Input
Removal Target	H		53	
Heat input	J	MM Btu/hr	1941.1	A X C x 1000
NSR	K		1.56	See Note DSI Note 1
Trona Feed rate	M	(tons/hr)	1.67	See Note DSI Note 2
Sorbent Waste Rate	N	(tons/hr)	1.13	See Note DSI Note 3
Fly Ash Waste Rate	P	(tons/hr)	5.55	See Note DSI Note 4
Aux Power	Q	(%)	0.21	See Note DSI Note 6
Trona Cost	R	($/ton)	150	Corrected to 2011 $
Waste Disposal Cost	S	($/ton)	50	
Aux Power Cost	T	($/kWhr)	0.06	
Operating Labor Rate	U	($/hr)	60	
CAPITAL EQUIPMENT COSTS				
Capital Cost	BM	($)	$17,387,979	Base DSI Module
Engineering, Construction Mgmt		5%	$869,399	
Construction Labor		5%	$869,399	
Contractor Profit and Fees		5%	$869,399	
Owners Cost		5%	$999,809	
Total Project Cost			$20,995,984	
			130	$/kW
OPERATING AND MAINTENANCE COSTS				
Fixed Operator Cost			$124,800	2,080 hrs- one operator
Maintenance Material			$173,880	1% of BM Capital Cost
Admin Labor Cost			$5,831	
Trona Cost			$250.46	Trona cost in $/hr
Waste Disposal Cost			$333.94	Total Waste Cost in $/hr

Notes:
1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-Dry Sorbent Injection Cost Development Methodology-FINAL", August 2010 Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

Table 4-2c

DRY SORBENT INJECTION COSTING DEVELOPMENT

MAX 24-HR SO_2 OPERATIONAL PARAMETERS

Variable	Designation	Units	Value	Equation/Input[1]
DRY INJECTION OPERATING VARIABLES - ACTUAL OPERATION AT 0.60 LBS/MMBTU SO_2				
Unit Capacity (Gross)	A	(MW)	162	Input
Retrofit Factor	B		2	Difficulty of Retrofit
Gross heat rate	C	Btu/KW-hr	11,982	Input
SO_2 Emiss Rate	D	lbs/MMBtu	0.6	Uncontrolled
Type of Coal	E	PRB		Input
Particulate Control	F	ESP		Input
Trona Milling	G	Yes		Input
Removal Target	H		57	
Heat input	J	MM Btu/hr	1941.1	A X C x 1000
NSR	K		1.74	See Note DSI Note 1
Trona Feed rate	M	(tons/hr)	2.44	See Note DSI Note 2
Sorbent Waste Rate	N	(tons/hr)	1.65	See Note DSI Note 3
Fly Ash Waste Rate	P	(tons/hr)	5.55	See Note DSI Note 4
Aux Power	Q	(%)	0.30	See Note DSI Note 6
Trona Cost	R	($/ton)	150	Corrected to 2011 $
Waste Disposal Cost	S	($/ton)	50	
Aux Power Cost	T	($/kWhr)	0.06	
Operating Labor Rate	U	($/hr)	60	
CAPITAL EQUIPMENT COSTS				
Capital Cost	BM	($)	$19,356,858	Base DSI Module
Engineering, Construction Mgmt		5%	$967,843	
Construction Labor		5%	$967,843	
Contractor Profit and Fees		5%	$967,843	
Owners Cost		5%	$1,113,019	
Total Project Cost		5%	$23,373,406	
			144	$/kW
OPERATING AND MAINTENANCE COSTS				
Fixed Operator Cost			$124,800	2,080 hrs- one operator
Maintenance Material			$193,569	1% of BM Capital Cost
Admin Labor Cost			$6,067	
Trona Cost			$365.41	Trona cost in $/hr
Waste Disposal Cost			$360.05	Waste Cost in $/hr

Notes:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-Dry Sorbent Injection Cost Development Methodology-FINAL", August 2010 Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

Table 4-2d
PPL BART Cost Effectiveness Analysis
Dry Injection (With Low Sulfur Coal) Sulfur Dioxide Control
162 Megawatt Coal Fired Steam Electric Plant
Trona Injection With Precipitator Replacement at J.E. Corette
SO_2 =0.46 lbs/MMBtu

Stack Exhaust Volumetric Flowrate, (acfm)	Q	726,262
Maximum Gross Heat Input	MM Btu/hr	1,941
Design Percent Load	%	89
Uncontrolled SO2 Emissions (with low S coal)	lbs/MMBtu	0.460
ExhaustTemperature, (^oF)	T	405
Steam Turbine Power Output (TMW)	MW	162
Capacity Factor (89%)	hrs	7,796
Controlled SO2 Emissions	lbs/MMBtu	0.26
Overall SO2 Reduction Efficiency, (%)	%	43.48
Uncontrolled SO2 Emissions, (lb/hr)		892.9
Uncontrolled SO2 Emissions, (tons/yr)		3480.7
Controlled SO2 Emissions, (ton/yr)		1967.4
Annual Interest Rate, (%)		7
Equipment Life, (yrs)	yr	15
Capital Recovery Factor, CRF	CRF	0.1098

Cost Item	Suggested Factor	Unit Cost	Item Cost
IPM Model, August 20, 2010[1]	Capital Cost ($/KW)[2]	225	$36,485,071
Cost for Pulse-Jet Fabric Filter	Capital Cost ($/KW)[3]	379	$61,398,000
Equipment Cost Total, (EC)	EC (Adjusted by Cost Index Calcs)	(2011 dollars)[4]	$101,615,582
Total Capital Costs, TCC		---	$101,615,582
Direct Annual Costs, DAC	Trona Cost		$1,952,695
	Total waste disposal Cost		$2,603,502
	Parasitic power cost		$156,216
	Lost Ash Revenue	$11.74/ton	$352,200
	Maintenance Labor		$130,631
	Maintenance Materials		$173,880
Total Direct Annual Costs, DAC			$5,369,123
Indirect Annual Costs			
Capital Recovery	CRF*TCC	---	$11,156,845
Total Indirect Annual Costs, IAC			$11,156,845
Total Annual Costs, TAC = DAC + IAC			$16,525,967
Cost Effectiveness ($/ton pollutant Removed)			$10,920

Cost data references:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-Dry Sorbent Injection Cost Development Methodology-FINAL", August 2010 Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

2) $/kW in 2009 dollars

3) $/kW in 2008 dollars (See Edison Electric Institute reference on page 26)

4) Cost indices used to adjust 2008 and 2009 costs to 2011 costs (2008, 2009 CI= 108.302, 109.594 2011 CI= 113.065)

Table 4-2e
PPL BART Cost Effectiveness Analysis
Dry Injection (With Low Sulfur Coal) Sulfur Dioxide Control
162 Megawatt Coal Fired Steam Electric Plant
Trona Injection With Precipitator Replacement at J.E. Corette
SO_2 =0.60 lbs/MMBtu

Stack Exhaust Volumetric Flowrate, (acfm)	Q	726,262
Maximum Gross Heat Input	MM Btu/hr	1,941
Design Percent Load	%	89
Uncontrolled SO2 Emissions (with low S coal)	lbs/MMBtu	0.600
ExhaustTemperature, (^oF)	T	405
Steam Turbine Power Output (TMW)	MW	162
Capacity Factor (89%)	hrs	7,796
Controlled SO2 Emissions	lbs/MMBtu	0.26
Overall SO2 Reduction Efficiency, (%)	%	56.67
Uncontrolled SO2 Emissions, (lb/hr)		1164.7
Uncontrolled SO2 Emissions, (tons/yr)		4540.1
Controlled SO2 Emissions, (ton/yr)		1967.4
Annual Interest Rate, (%)		7
Equipment Life, (yrs)	yr	15
Capital Recovery Factor, CRF	CRF	0.1098

Cost Item	Suggested Factor	Unit Cost	Item Cost
IPM Model, August 20, 2010[1]	Capital Cost ($/KW)[2]	225	$36,485,071
Cost for Pulse-Jet Fabric Filter	Capital Cost ($/KW)[3]	379	$61,398,000
Equipment Cost Total, (EC)	EC (Adjusted by Cost Index Calcs)	(2011 dollars)[4]	$101,615,582
Total Capital Costs, TCC		---	$101,615,582
Direct Annual Costs, DAC	Trona Cost		$2,848,845
	Total waste disposal Cost		$2,807,072
	Parasitic power cost		$227,908
	Lost Ash Revenue	$11.74/ton	$352,200
	Maintenance Labor		$130,867
	Maintenance Materials		$193,569
Total Direct Annual Costs, DAC			$6,560,460
Indirect Annual Costs			
Capital Recovery	CRF*TCC	---	$11,156,845
Total Indirect Annual Costs, IAC			$11,156,845
Total Annual Costs, TAC = DAC + IAC			$17,717,304
Cost Effectiveness ($/ton pollutant Removed)			$6,887

Cost data references:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-Dry Sorbent Injection Cost Development Methodology-FINAL", August 2010 Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

2) $/kW in 2009 dollars

3) $/kW in 2008 dollars (See Edison Electric Institute reference on page 26)

4) Cost indices used to adjust 2008 and 2009 costs to 2011 costs (2008, 2009 CI= 108.302, 109.594 2011 CI= 113.065)

Table 4-3a
SPRAY DRYER ABSORBER COSTING DEVELOPMENT
DESIGN CASE FOR CAPITAL COSTS

Variable	Designation	Units	Value	Equation/Input[1]
LIME SPRAY DRYER CAPITAL COST DESIGN BASIS FOR 2 LBS/MMBTU SO_2				
Unit Capacity (Gross)	A	(MW)	162	Input
Retrofit Factor	B		2	Difficulty of Retrofit
Gross heat rate	C	Btu/KW-hr	11,982	Input
SO_2 Emiss Rate	D	lbs/MMBtu	2	Uncontrolled
Type of Coal	E	PRB		Input
Coal Factor	F	PRB Coal	1.05	Input
Heat Rate Factor	G		1.20	C / 10000
Heat input	H	MM Btu/hr	1941.1	A X C x 1000
Lime Rate	K	(tons/hr)	2.87	See SDA Note 1
Waste Rate	L	(tons/hr)	6.37	See SDA Note 2
Aux Power	M	(%)	1.65	See SDA Note 7
Make Up Water	N	10^3 gph	11.51	See SDA Note 3
Lime Cost	P	($/ton)	135.00	Input
Waste Disposal Cost	S	($/ton)	50	Input
Aux Power Cost	R	($/kWhr)	0.06	Input
Makeup Water Cost	S	$/$10^3$ gal	1	Input
Operating Labor Rate	T	($/hr)	60	Input
CAPITAL EQUIPMENT COSTS				
Basic Absorber	BMR	($)	$49,281,061	See SDA Note 4
Reagent Preparation	BMF	($)	$27,294,545	See SDA Note 5
ID Fan, Other Costs	BMB	($)	$66,907,834	See SDA Note 6
Capital Cost	BM Sum	($)	$143,483,440	Base LSD Module
Engineering, Construction Mgmt		10%	$14,348,344	
Construction Labor		10%	$14,348,344	
Contractor Fees		10%	$14,348,344	
	CECC		$186,528,472	Capital, Eng, and Const
Owners Cost	B1	5%	$9,326,424	Various home office fees
AFUDC		10% of (CECC+B1)	$19,585,490	
Total Project Cost			$215,440,385	
			1,330	$/kW
OPERATING AND MAINTENANCE COSTS				
Fixed Operator Cost			$998,400	2,080 hrs- 8 operators
Maintenance Material			$4,304,503	1.5% of BM Capital Cost
Admin Labor Cost			$81,606	
Lime Cost			$386.79	Lime cost in $/hr
Waste Disposal Cost			$318.29	Waste Cost in $/hr

Notes:
1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-SDA FDG Cost Development Methodology-FINAL", August 2010
Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

Table 4-3b

SPRAY DRYER COSTING DEVELOPMENT

30-DAY ROLLING AVERAGE SO_2 OPERATING PARAMETERS

Variable	Designation	Units	Value	Equation/Input[1]
LIME SPRAY DRYER OPERATING VARIABLES - ACTUAL OPERATION AT 0.46 LBS/MMBTU SO_2				
Unit Capacity (Gross)	A	(MW)	162	Input
Retrofit Factor	B		2	Difficulty of Retrofit
Gross heat rate	C	Btu/KW-hr	11,982	Input
SO_2 Emiss Rate	D	lbs/MMBtu	0.46	Uncontrolled
Type of Coal	E	PRB		Input
Coal Factor	F	PRB Coal	1.05	Input
Heat Rate Factor	G		1.20	C / 10000
Heat input	H	MM Btu/hr	1941.1	A X C x 1000
Lime Rate	K	(tons/hr)	0.61	See SDA Note 1
Waste Rate	L	(tons/hr)	1.41	See SDA Note 2
Aux Power	M	(%)	1.64	See SDA Note 7
Make Up Water	N	10^3 gph	11.29	See SDA Note 3
Lime Cost	P	($/ton)	135.00	Input
Waste Disposal Cost	S	($/ton)	50	Input
Aux Power Cost	R	($/kWhr)	0.06	Input
Makeup Water Cost	S	$/$10^3$ gal	1	Input
Operating Labor Rate	T	($/hr)	60	Input
CAPITAL EQUIPMENT COSTS				
Basic Absorber	BMR	($)	$48,562,085	See SDA Note 4
Reagent Preparation	BMF	($)	$20,343,301	See SDA Note 5
ID Fan, Other Costs	BMB	($)	$66,907,834	See SDA Note 6
Capital Cost	BM Sum	($)	$135,813,220	Base LSD Module
Engineering, Construction Mgmt		10%	$13,581,322	
Construction Labor		10%	$13,581,322	
Contractor Fees		10%	$13,581,322	
	CECC		$176,557,186	Capital, Eng, and Const
Owners Cost	B1	5%	$8,827,859	Various home office fees
AFUDC		10% of (CECC+B1)	$18,538,505	
Total Project Cost			$203,923,550	
			1,259	$/kW
OPERATING AND MAINTENANCE COSTS				
Fixed Operator Cost			$998,400	2,080 hrs- 8 operators
Maintenance Material			$4,074,397	1.5% of BM Capital Cost
Admin Labor Cost			$78,845	
Lime Cost			$82.74	Lime cost in $/hr
Waste Disposal Cost			$70.45	Waste Cost in $/hr

Notes:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-SDA FDG Cost Development Methodology-FINAL", August 2010 Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

Table 4-3c

SPRAY DRYER ABSORBER COSTING DEVELOPMENT

MAXIMUM 24-HR AVERAGE SO_2 OPERATING PARAMETERS

Variable	Designation	Units	Value	Equation/Input[1]
LIME SPRAY DRYER OPERATING VARIABLES - ACTUAL OPERATION AT 0.60 LBS/MMBTU SO_2				
Unit Capacity (Gross)	A	(MW)	162	Input
Retrofit Factor	B		2	Difficulty of Retrofit
Gross heat rate	C	Btu/KW-hr	11,982	Input
SO_2 Emiss Rate	D	lbs/MMBtu	0.6	Uncontrolled
Type of Coal	E	PRB		Input
Coal Factor	F	PRB Coal	1.05	Input
Heat Rate Factor	G		1.20	C / 10000
Heat input	H	MM Btu/hr	1941.1	A X C x 1000
Lime Rate	K	(tons/hr)	0.80	See SDA Note 1
Waste Rate	L	(tons/hr)	1.84	See SDA Note 2
Aux Power	M	(%)	1.64	See SDA Note 7
Make Up Water	N	10^3 gph	11.31	See SDA Note 3
Lime Cost	P	($/ton)	135.00	Input
Waste Disposal Cost	S	($/ton)	50	Input
Aux Power Cost	R	($/kWhr)	0.06	Input
Makeup Water Cost	S	$/$10^3$ gal	1	Input
Operating Labor Rate	T	($/hr)	60	Input
CAPITAL EQUIPMENT COSTS				
Basic Absorber	BMR	($)	$48,691,288	See SDA Note 4
Reagent Preparation	BMF	($)	$21,453,597	See SDA Note 5
ID Fan, Other Costs	BMB	($)	$66,907,834	See SDA Note 6
Capital Cost	BM Sum	($)	$137,052,718	Base LSD Module
Engineering, Construction Mgmt		10%	$13,705,272	
Construction Labor		10%	$13,705,272	
Contractor Fees		10%	$13,705,272	
	CECC		$178,168,534	Capital, Eng, and Const
Owners Cost	B1	5%	$8,908,427	Various home office fees
AFUDC		10% of (CECC+B1)	$18,707,696	
Total Project Cost			$205,784,657	
			1,270	$/kW
OPERATING AND MAINTENANCE COSTS				
Fixed Operator Cost			$998,400	2,080 hrs- 8 operators
Maintenance Material			$4,111,582	1.5% of BM Capital Cost
Admin Labor Cost			$79,291	
Lime Cost			$108.66	Lime cost in $/hr
Waste Disposal Cost			$92.22	Waste Cost in $/hr

Notes:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-SDA FDG Cost Development Methodology-FINAL", August 2010 Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

Table 4-3d
PPL BART Cost Effectiveness Analysis
Lime Spray Drying (With Low Sulfur Coal) Sulfur Dioxide Control
162 Megawatt Coal Fired Steam Electric Plant
Lime Spray Drying With Precipitator Replacement at J.E. Corette
SO_2 =0.46 lbs/MMBtu

Stack Exhaust Volumetric Flowrate, (acfm)	Q	726,262
Maximum Gross Heat Input	MM Btu/hr	1,941
Design Percent Load	%	89
Uncontrolled SO2 Emissions (with low S coal)	lbs/MMBtu	0.460
ExhaustTemperature, (°F)	T	405
Steam Turbine Power Output (TMW)	MW	162
Capacity Factor (89%)	hrs	7,796
Controlled SO2 Emissions	lbs/MMBtu	0.13
Overall SO2 Reduction Efficiency, (%)	%	71.74
Uncontrolled SO2 Emissions, (lb/hr)		892.9
Uncontrolled SO2 Emissions, (tons/yr)		3480.7
Controlled SO2 Emissions, (ton/yr)		983.7
Annual Interest Rate, (%)		7
Equipment Life, (yrs)	yr	15
Capital Recovery Factor, CRF	CRF	0.1098

Cost Item	Suggested Factor	Unit Cost	Item Cost
IPM Model, August 20, 2010[(1)]	Capital Cost ($/KW)[(2)]	1,330	$215,440,385
Cost for Pulse-Jet Fabric Filter	Capital Cost ($/KW)[(3)]	379	$61,398,000
Equipment Cost Total, (EC)	EC (Adjusted by Cost Index Calcs)	(2011 dollars)[(4)]	$285,634,195
Total Capital Costs, TCC		---	$285,634,195
Direct Annual Costs, DAC	Lime		$645,084
	Total waste disposal Cost		$549,262
	Parasitic power cost		$1,242,388
	Lost Ash Revenue	$11.74/ton	$352,200
	Stack Reheat Penalty	reheat to 300°F	$7,740,315
	Maintenance labor		$1,077,245
	Maintenance materials		$4,074,397
Total Direct Annual Costs, DAC			$15,680,890
Indirect Annual Costs			
Capital Recovery	CRF*TCC	---	$31,361,099
Total Indirect Annual Costs, IAC			$31,361,099
Total Annual Costs, TAC = DAC + IAC			$47,041,990
Cost Effectiveness ($/ton pollutant Removed)			$18,839

Cost data references:
1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-Dry Sorbent Injection Cost Development Methodology-FINAL", August 2010 Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC
2) $/kW in 2009 dollars
3) $/kW in 2008 dollars (See Edison Electric Institute reference on page 26)
4) Cost indices used to adjust 2008 and 2009 costs to 2011 costs (2008, 2009 CI= 108.302, 109.594 2011 CI= 113.065)

Table 4-3e
PPL BART Cost Analysis
Lime Spray Drying (With Low Sulfur Coal) Sulfur Dioxide Control
162 Megawatt Coal Fired Steam Electric Plant
Lime Spray Drying With Precipitator Replacement at J.E. Corette
SO_2 =0.60 lbs/MMBtu

Stack Exhaust Volumetric Flowrate, (acfm)	Q	726,262
Maximum Gross Heat Input	MM Btu/hr	1,941
Design Percent Load	%	89
Uncontrolled SO2 Emissions (with low S coal)	lbs/MMBtu	0.600
ExhaustTemperature, (^oF)	T	405
Steam Turbine Power Output (TMW)	MW	162
Capacity Factor (89%)	hrs	7,796
Controlled SO2 Emissions	lbs/MMBtu	0.13
Overall SO2 Reduction Efficiency, (%)	%	78.33
Uncontrolled SO2 Emissions, (lb/hr)		1164.7
Uncontrolled SO2 Emissions, (tons/yr)		4540.1
Controlled SO2 Emissions, (ton/yr)		983.7
Annual Interest Rate, (%)		7
Equipment Life, (yrs)	yr	15
Capital Recovery Factor, CRF	CRF	0.1098

Cost Item	Suggested Factor	Unit Cost	Item Cost
IPM Model, August 20, 2010[1]	Capital Cost ($/KW)[2]	1,330	$215,440,385
Cost for Pulse-Jet Fabric Filter	Capital Cost ($/KW)[3]	379	$61,398,000
Equipment Cost Total, (EC)	EC (Adjusted by Cost Index Calcs)	(2011 dollars)[4]	$285,634,195
Total Capital Costs, TCC		---	$285,634,195
Direct Annual Costs, DAC	Lime		$847,165
	Total waste disposal Cost		$718,976
	Parasitic power cost		$1,243,331
	Lost Ash Revenue	$11.74/ton	$352,200
	Stack Reheat Penalty	reheat to 300^oF	$7,740,315
	Maintenance labor		$1,077,691
	Maintenance materials		$4,111,582
Total Direct Annual Costs, DAC			$16,091,260
Indirect Annual Costs			
Capital Recovery	CRF*TCC	---	$31,361,099
Total Indirect Annual Costs, IAC			$31,361,099
Total Annual Costs, TAC = DAC + IAC			$47,452,359
Cost Effectiveness ($/ton pollutant Removed)			$13,343

Cost data references:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-Dry Sorbent Injection Cost Development Methodology-FINAL", August 2010 Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

2) $/kW in 2009 dollars

3) $/kW in 2008 dollars (See Edison Electric Institute reference on page 26)

4) Cost indices used to adjust 2008 and 2009 costs to 2011 costs (2008, 2009 CI= 108.302, 109.594 2011 CI= 113.065)

Table 4-4a
WET FGD COSTING DEVELOPMENT
DESIGN BASIS FOR CAPITAL COST

Variable	Designation	Units	Value	Equation/Input[1]
WET FGD CAPITAL COST DESIGN BASIS FOR 2 LBS/MMBTU SO_2				
Unit Capacity (Gross)	A	(MW)	162	Input
Retrofit Factor	B		2	Difficulty of Retrofit
Gross heat rate	C	Btu/KW-hr	11,982	Input
SO_2 Emiss Rate	D	lbs/MMBtu	2	Uncontrolled
Type of Coal	E	PRB		Input
Coal Factor	F	PRB Coal	1.05	Input
Heat Rate Factor	G		1.20	C / 10000
Heat input	H	MM Btu/hr	1941.1	A X C x 1000
Limestone Rate	K	(tons/hr)	3.40	See FGD Note 1
Waste Rate	L	(tons/hr)	6.16	See FGD Note 2
Aux Power	M	(%)	1.80	See FGD Note 8
Make Up Water	N	10^3 gph	15.90	See FGD Note 3
Limestone Cost	P	($/ton)	15.00	
Waste Disposal Cost	S	($/ton)	50	
Aux Power Cost	R	($/kWhr)	0.06	
Makeup Water Cost	S	$/$10^3$ gal	1	
Operating Labor Rate	T	($/hr)	60	
CAPITAL EQUIPMENT COSTS				
Basic Absorber	BMR	($)	$48,221,043	See FGD Note 4
Reagent Preparation	BMF	($)	$18,865,318	See FGD Note 5
Waste Handling Cost	BMW	($)	$11,319,948	See FGD Note 6
ID Fan, Other Costs	BMB	($)	$84,576,862	See FGD Note 7
Capital Cost	BM Sum	($)	$162,983,172	Base Wet FGD Module
Engineering, Construction Mgmt		10%	$16,298,317	
Construction Labor		10%	$16,298,317	
Contractor Fees		10%	$16,298,317	
	CECC		$211,878,123	Capital, Eng, and Const
Owners Cost	B1	5%	$10,593,906	Various home office fees
AFUDC		10% of (CECC+B1)	$22,247,203	
Total Project Cost			$244,719,232	
			1,511	$/kW
OPERATING AND MAINTENANCE COSTS				
Fixed Operator Cost	FOMO		$1,497,600	2,080 hrs- 12 operators
Maintenance Material			$4,889,495	1.5% of BM Capital Cost
Admin Labor Cost			$103,602	
Auxiliary Power			$175.07	$/hr
Water Cost			$15.90	$/hr
Limestone Cost			$323.07	Limestone cost in $/hr
Waste Disposal Cost			$307.94	Waste Cost in $/hr

Notes:
1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-Wet FGD Cost Development Methodology-FINAL", August 2010
Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

Table 4-4b

WET FGD COSTING DEVELOPMENT

30-DAY ROLLING AVERAGE SO_2 OPERATING PARAMETERS

Variable	Designation	Units	Value	Equation/Input[1]
WET FGD OPERATING VARIABLES - ACTUAL OPERATION AT 0.46 LBS/MMBTU SO_2				
Unit Capacity (Gross)	A	(MW)	162	Input
Retrofit Factor	B		2	Difficulty of Retrofit
Gross heat rate	C	Btu/KW-hr	11,982	Input
SO_2 Emiss Rate	D	lbs/MMBtu	0.46	Uncontrolled
Type of Coal	E	PRB		Input
Coal Factor	F	PRB Coal	1.05	Input
Heat Rate Factor	G		1.20	C / 10000
Heat input	H	MM Btu/hr	1941.1	A X C x 1000
Limestone Rate	K	(tons/hr)	0.78	See FGD Note 1
Waste Rate	L	(tons/hr)	1.42	See FGD Note 2
Aux Power	M	(%)	1.42	See FGD Note 8
Make Up Water	N	10^3 gph	15.38	See FGD Note 3
Limestone Cost	P	($/ton)	15.00	
Waste Disposal Cost	S	($/ton)	50	
Aux Power Cost	R	($/kWhr)	0.06	
Makeup Water Cost	S	$/$10^3$ gal	1	
Operating Labor Rate	T	($/hr)	60	
CAPITAL EQUIPMENT COSTS				
Basic Absorber	BMR	($)	$46,824,286	See FGD Note 4
Reagent Preparation	BMF	($)	$12,138,988	See FGD Note 5
Waste Handling Cost	BMW	($)	$5,842,813	See FGD Note 6
ID Fan, Other Costs	BMB	($)	$84,576,862	See FGD Note 7
Capital Cost	BM Sum	($)	$149,382,948	Base Wet FGD Module
Engineering, Construction Mgmt		10%	$14,938,295	
Construction Labor		10%	$14,938,295	
Contractor Fees		10%	$14,938,295	
	CECC		$194,197,833	Capital, Eng, and Const
Owners Cost	B1	5%	$9,709,892	Various home office fees
AFUDC		10% of (CECC+B1)	$20,390,772	
Total Project Cost			$224,298,497	
			1,385	$/kW
OPERATING AND MAINTENANCE COSTS				
Fixed Operator Cost	FOMO		$1,497,600	2,080 hrs- 12 operators
Maintenance Material			$4,481,488	1.5% of BM Capital Cost
Admin Labor Cost			$98,706	
Auxiliary Power			$137.89	$/hr
Water Cost			$15.38	$/hr
Limestone Cost			$74.31	Limestone cost in $/hr
Waste Disposal Cost			$70.83	Waste Cost in $/hr

Notes:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-Wet FGD Cost Development Methodology-FINAL", August 2010

Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

Table 4-4c

WET FGD COSTING DEVELOPMENT

MAXIMUM 24-HR AVERAGE SO_2 OPERATING PARAMETERS

Variable	Designation	Units	Value	Equation/Input[1]
WET FGD OPERATING VARIABLES - ACTUAL OPERATION AT 0.60 LBS/MMBTU SO_2				
Unit Capacity (Gross)	A	(MW)	162	Input
Retrofit Factor	B		2	Difficulty of Retrofit
Gross heat rate	C	Btu/KW-hr	11,982	Input
SO_2 Emiss Rate	D	lbs/MMBtu	0.6	Uncontrolled
Type of Coal	E	PRB		Input
Coal Factor	F	PRB Coal	1.05	Input
Heat Rate Factor	G		1.20	C / 10000
Heat input	H	MM Btu/hr	1941.1	A X C x 1000
Limestone Rate	K	(tons/hr)	1.02	See FGD Note 1
Waste Rate	L	(tons/hr)	1.85	See FGD Note 2
Aux Power	M	(%)	1.45	See FGD Note 8
Make Up Water	N	10^3 gph	15.43	See FGD Note 3
Limestone Cost	P	($/ton)	15.00	
Waste Disposal Cost	S	($/ton)	50	
Aux Power Cost	R	($/kWhr)	0.06	
Makeup Water Cost	S	$/$10^3$ gal	1	
Operating Labor Rate	T	($/hr)	60	
CAPITAL EQUIPMENT COSTS				
Basic Absorber	BMR	($)	$47,073,775	See FGD Note 4
Reagent Preparation	BMF	($)	$13,146,209	See FGD Note 5
Waste Handling Cost	BMW	($)	$6,584,897	See FGD Note 6
ID Fan, Other Costs	BMB	($)	$84,576,862	See FGD Note 7
Capital Cost	BM Sum	($)	$151,381,743	Base Wet FGD Module
Engineering, Construction Mgmt		10%	$15,138,174	
Construction Labor		10%	$15,138,174	
Contractor Fees		10%	$15,138,174	
	CECC		$196,796,265	Capital, Eng, and Const
Owners Cost	B1	5%	$9,839,813	Various home office fees
AFUDC		10% of (CECC+B1)	$20,663,608	
Total Project Cost			$227,299,686	
			1,403	$/kW
OPERATING AND MAINTENANCE COSTS				
Fixed Operator Cost	FOMO		$1,497,600	2,080 hrs- 12 operators
Maintenance Material			$4,541,452	1.5% of BM Capital Cost
Admin Labor Cost			$99,425	
Auxiliary Power			$140.92	$/hr
Water Cost			$15.43	$/hr
Limestone Cost			$96.92	Limestone cost in $/hr
Waste Disposal Cost			$92.38	Waste Cost in $/hr

Notes:

1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-Wet FGD Cost Development Methodology-FINAL", August 2010

Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC

Table 4-4d
PPL BART Cost Analysis
Wet FGD (With Low Sulfur Coal) Sulfur Dioxide Control
162 Megawatt Coal Fired Steam Electric Plant
Wet FGD at J.E. Corette
SO_2 =0.46 lbs/MMBtu

Stack Exhaust Volumetric Flowrate, (acfm)	Q	726,262
Maximum Gross Heat Input	MM Btu/hr	1,941
Design Percent Load	%	89
Uncontrolled SO2 Emissions (with low S coal)	lbs/MMBtu	0.460
ExhaustTemperature, (^oF)	T	405
Steam Turbine Power Output (TMW)	MW	162
Capacity Factor (89%)	hrs	7,796
Controlled SO2 Emissions	lbs/MMBtu	0.06
Overall SO2 Reduction Efficiency, (%)	%	86.96
Uncontrolled SO2 Emissions, (lb/hr)		892.9
Uncontrolled SO2 Emissions, (tons/yr)		3480.7
Controlled SO2 Emissions, (ton/yr)		454.0
Annual Interest Rate, (%)		7
Equipment Life, (yrs)	yr	15
Capital Recovery Factor, CRF	CRF	0.1098

Cost Item	Suggested Factor	Unit Cost	Item Cost
IPM Model, August 20, 2010[1]	Capital Cost ($/KW)[2]	1,511	$244,719,232
Equipment Cost Total, (EC)	EC (Adjusted by Cost Index Calcs)	(2011 dollars)[3]	$252,469,843
Total Capital Costs, TCC		---	$252,469,843
Direct Annual Costs, DAC	Limestone Cost		$579,327
	Waste disposal Cost		$552,190
	Parasitic power cost		$1,075,062
	Lost Ash Revenue	$11.74/ton	$352,200
	Stack Reheat Penalty	reheat to 300^oF	$10,965,447
	Operator and Admin Labor		$1,596,306
	Maintenance Materials		$4,481,488
Total Direct Annual Costs, DAC			$19,602,020
Indirect Annual Costs			
Capital Recovery	CRF*TCC	---	$27,719,832
Total Indirect Annual Costs, IAC			$27,719,832
Total Annual Costs, TAC = DAC + IAC			$47,321,852
Cost Effectiveness ($/ton pollutant Removed)			$15,635

Cost data references:
1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-Wet FGD Cost Development Methodology-FINAL", August 2010
Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC
2) $/kW in 2009 dollars
3) Cost indices used to adjust 2009 costs to 2011 costs (2009 CI= 109.954, 2011 CI= 113.065)

Table 4-4e
PPL BART Cost Analysis
Wet FGD (With Low Sulfur Coal) Sulfur Dioxide Control
162 Megawatt Coal Fired Steam Electric Plant
Wet FGD at J.E. Corette
SO_2 =0.60 lbs/MMBtu

Stack Exhaust Volumetric Flowrate, (acfm)	Q	726,262
Maximum Gross Heat Input	MM Btu/hr	1,941
Design Percent Load	%	89
Uncontrolled SO2 Emissions (with low S coal)	lbs/MMBtu	0.600
ExhaustTemperature, (^oF)	T	405
Steam Turbine Power Output (TMW)	MW	162
Capacity Factor (89%)	hrs	7,796
Controlled SO2 Emissions	lbs/MMBtu	0.06
Overall SO2 Reduction Efficiency, (%)	%	90.00
Uncontrolled SO2 Emissions, (lb/hr)		1164.7
Uncontrolled SO2 Emissions, (tons/yr)		4540.1
Controlled SO2 Emissions, (ton/yr)		454.0
Annual Interest Rate, (%)		7
Equipment Life, (yrs)	yr	15
Capital Recovery Factor, CRF	CRF	0.1098

Cost Item	Suggested Factor	Unit Cost	Item Cost
IPM Model, August 20, 2010[1]	Capital Cost ($/KW)[2]	1,511	$244,719,232
Equipment Cost Total, (EC)	EC (Adjusted by Cost Index Calcs)	(2011 dollars)[3]	$252,469,843
Total Capital Costs, TCC		---	$252,469,843
Direct Annual Costs, DAC	Limestone Cost		$755,644
	Waste disposal Cost		$720,248
	Parasitic power cost		$1,098,646
	Lost Ash Revenue	$11.74/ton	$352,200
	Stack Reheat Penalty	reheat to 300^oF	$10,965,447
	Operator and Admin Labor		$1,596,306
	Maintenance Materials		$4,541,452
Total Direct Annual Costs, DAC			$20,029,943
Indirect Annual Costs			
Capital Recovery	CRF*TCC	---	$27,719,832
Total Indirect Annual Costs, IAC			$27,719,832
Total Annual Costs, TAC = DAC + IAC			$47,749,775
Cost Effectiveness ($/ton pollutant Removed)			$11,686

Cost data references:
1) Cost analysis equations from "IPM Model-Revisions to Cost And Performance for APC Technologies-Wet FGD Cost Development Methodology-FINAL", August 2010
Project 12301-007, Perrin Quarles Associates, Inc., prepared by Sargent & Lundy, LLC
2) $/kW in 2009 dollars
3) Cost indices used to adjust 2009 costs to 2011 costs (2009 CI= 109.954, 2011 CI= 113.065)