IPM Model – Updates to Cost and Performance for APC Technologies

SNCR Cost Development Methodology

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Purpose of Cost Algorithms for the IPM Model

The primary purpose of the cost algorithms is to provide generic order-of-magnitude costs for various air quality control technologies that can be applied to the electric power generating industry on a system-wide basis, not on an individual unit basis. Cost algorithms developed for the IPM model are based primarily on a statistical evaluation of cost data available from various industry publications as well as Sargent & Lundy's proprietary database and do not take into consideration site-specific cost issues. By necessity, the cost algorithms were designed to require minimal site-specific information and were based only on a limited number of inputs such as unit size, gross heat rate, baseline emissions, removal efficiency, fuel type, and a subjective retrofit factor.

The outputs from these equations represent the "average" costs associated with the "average" project scope for the subset of data utilized in preparing the equations. The IPM cost equations do not account for site-specific factors that can significantly impact costs, such as flue gas volume or temperature, and do not address regional labor productivity, local workforce characteristics, local unemployment and labor availability, project complexity, local climate, and working conditions. In addition, the indirect capital costs included in the IPM cost equations do not account for all project-related indirect costs a facility would incur to install a retrofit control such as a project contingency.

Establishment of the Cost Basis

The formulation of the SNCR cost estimating model is based upon a proprietary Sargent & Lundy LLC (S&L) in-house data base of recent (2009 to 2016) quotes for both lump-sum contracts and Engineering, Procurement and Construction (EPC) contracts. The S&L data were analyzed in detail regarding project specifics such as coal type, boiler type, and NO_x reduction efficiency. The S&L in-house data includes projects that involved cyclone boilers and T-fired and wall-fired systems with multiple levels of injection. The cyclone boiler costs include rich reagent injection (RRI). The data was the basis for the cost estimate algorithms developed.

The S&L data were fitted with a least-squares curve to establish the trend in $/kW as a function of gross MW. The SNCR cost model parameters were adjusted to account for market changes and escalation, and then the model output was compared to the S&L data. The model output followed a $/kW correlation very similar to the S&L in-house data, once the adjustments were made to the model.

The rapid rise in project costs at the lower end of the MW range is due primarily to economies of scale. Additionally, older power plants in the 50-MW range tend to have plant sites that are more compact, and therefore it is difficult to accommodate the reagent storage areas and piping, injection mixing/dilution equipment, and construction activities. The smaller power plants also tend to have older control systems that may require upgrades to accommodate the new SNCR control system. S&L is not aware of any SNCR installations in recent years for smaller than 100-MW utility units. In light of recent retirement of smaller than 200-W size units, the evaluation of SNCR technology may not be necessary. There are not many utilities that we are aware of operating smaller than 25-MW units. Most of these units are operated by universities, hospitals, or industries that need heat and power. Industrial MACT has basically covered most of these units, and they are required to add pollution controls. In particular, a number of cement kilns have added SNCR systems for NO_x control. The algorithm prepared in the study should not be used to estimate the SNCR system costs of smaller than 50-MW electric generating units or boilers.

A combined SNCR for small units is not a feasible option. The urea solution injection takes place in the boiler. Each boiler has to be retrofitted with multiple levels of injectors to achieve maximum NO_X removal. Minor amount of saving can be achieved by utilizing a common reagent storage and preparation system.

The SNCR efficiency is significantly lower for large boilers compared to small boilers primarily due to the large penetration required for urea droplets to cover the flue gas. For units greater than 500 MW that achieve 0.15 lb/MBtu NO_X, only 15 to 20% NO_X reduction may be achievable.

The SNCRs for Fluidized-Bed Combustors (FBC) are more effective than PC boilers primarily due to long residence time in the boiler in a desired temperature zone. The SNCRs on FBC boilers have shown to achieve up to 50% efficiency with target floor emission as low as 0.08 lb/MBtu.

The S&L data includes SNCR projects with various types of boilers, coals, sulfur levels, and retrofit complexities. The typical SNCR retrofit was based on:

- Retrofit Difficulty = 1 (Average retrofit difficulty);
- Gross Heat Rate = 9800 Btu/kWh;
- SO_2 Rate = < 3 lb/MMBtu;
- Type of Coal = PRB; and
- Project Execution = Multiple lump-sum contracts.

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Methodology

Inputs

To predict future retrofit costs several input variables are required. The unit size in MW and NO_x levels are the major variables for the capital cost estimation followed by the type of fuel. The fuel type affects the air pre-heater costs if sulfuric acid or ammonium bisulfate deposition poses a problem. In general, if the level of SO_2 is above 3 lb/MMBtu, it is assumed that air heater modifications will be required. The unit heat rate factors into the amount of NO_x generated and ultimately the size of the SNCR reagent preparation system. A retrofit factor that equates to the difficulty of constructing the system must be defined. The NO_x rate and removal efficiency will impact the amount of urea required and the size of the reagent handling equipment. Finally, the boiler type will influence the capital costs of the SNCR system and the balance of plant considerations.

The cost methodology is based on a unit located within 500 feet of sea level. The actual elevation of the site should be considered separately and factored into the cost due to the effects on the flue gas volume. The base SNCR costs are directly impacted by the site elevation. This base cost module should be increased based on the ratio of the atmospheric pressure at sea level and that at the unit location. As an example, a unit located 1 mile above sea level would have an approximate atmospheric pressure of 12.2 psia. Therefore, the base SNCR cost should be increased by:

$$14.7 \text{ psia}/12.2 \text{ psia} = 1.2 \text{ multiplier to the base SNCR cost}$$

Outputs

Total Project Costs (TPC)

First, the installed costs are calculated for each required base module. The base module installed costs include:

- All equipment;
- Installation;
- Buildings;
- Foundations;
- Electrical;
- Water treatment for the dilution water; and
- Retrofit difficulty.

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The base modules are:

BMS =	Base SNCR system
BMA =	Base air heater modifications, as required
BMB =	Base balance of plant costs including: piping, site upgrades, water treatment for the dilution water, etc...
BM =	BMS + BMA + BMB

The total base module 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 0% of the CECC and owner's costs as these projects are expected to be completed in less than a year after the equipment is released for the fabrication.

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.

Based on in-house projects since 2012, no changes in the capital cost have been observed. The capital cost algorithm developed for 2012 is, therefore, still valid for 2016.

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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 SNCR 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 are tabulated on a per-kilowatt-year (kW yr) basis.
- In general, no additional operators are required for a new SNCR system.
- The fixed maintenance materials and labor are a direct function of the process capital cost at 1.2% of the BM.
- The administrative labor is a function of the FOMO and FOMM at 3% of the sum of (FOMO + 0.4 FOMM).

Variable O&M (VOM)

Variable O&M is a function of:

- Reagent use and unit costs;
- Dilution water required and unit water cost;
- Additional power required and unit power cost; and
- Boiler efficiency reduction due to the added water in the boiler and unit replacement coal 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 the amount of NO_x removed, NO_x inlet rate, and boiler type. A utilization factor (UF) of 15% is used for units with an inlet NO_x of 0.3 lb/MMBtu or lower and 25% for units with an inlet NO_x greater than 0.3 lb/MMBtu. For CFB boilers a utilization factor of 25% is used.
- The dilution water usage is based on creating a 5% dilute reagent stream for injection into the boiler.
- The additional power required includes compressed air or blower requirements for the urea injection system and the reagent supply system.
- The additional power is reported as a percentage of the total unit gross production. In addition, a cost associated with the additional power requirements can be included in the total variable costs.

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- Impacts on the unit heat rate due to injection of liquid water into the boiler are accounted for by additional coal costs to provide added boiler heat input and can be included in the total variable costs.

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:

- Urea cost for a 50% by weight solution in $/ton; due to escalation, this cost was updated to reflect average 2016 pricing. The urea solution cost includes the cost of a 50% urea solution prepared at the manufacturing site with additives suitable for avoiding corrosion in the injectors and transportation cost. The solution cost is significantly higher than that of the solid urea. If solid urea is purchased, it would require additional storage, solutionizing equipment, and additional deionized water processing capability at the plant site.
- Auxiliary power cost in $/kWh. No noticeable escalation has been observed for auxiliary power cost since 2013.
- Dilution water cost in $/1000 gallon.
- Operating labor rate (including all benefits) in $/hr.
- Replacement coal cost in $/MMBtu.

The variables that contribute to the overall VOM are:

VOMR = Variable O&M costs for urea reagent

VOMM = Variable O&M costs for dilution water

VOMP = Variable O&M costs for additional auxiliary power

VOMB = Variable O&M costs for additional coal

The total VOM is the sum of VOMR, VOMM, VOMP, and VOMB. Table 1 shows a complete capital and O&M cost estimate worksheet for an SNCR on a T-fired boiler. Table 2 shows a complete capital and O&M cost estimate worksheet for an SNCR on a CFB boiler.

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Table 1. Example of a Complete Cost Estimate for an SNCR System Installed on a T-fired boiler

Variable	Designation	Units	Value	Calculation
Boiler Type	BT		Tangential	<--- User Input
Unit Size	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	9800	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.22	<--- User Input
SO2 Rate	E	(lb/MMBtu)	2	<--- User Input
Type of Coal	F		Bituminous	<--- User Input
Coal Factor	G		1	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	H		0.98	C/10,000
Heat Input	I	(Btu/hr)	4.90E+09	A*C*1000
NOx Removal Efficiency	K	(%)	25	
NOx Removed	L	(lb/hr)	270	D*I/10^6*K/100
Urea Rate (100%)	M	(lb/hr)	1172	L/UF/46*30; IF Boiler Type = CFB OR D > 0.3 THEN UF = 0.25; ELSE UF = 0.15
Water Required	N	(lb/hr)	22263	M*19
Heat Rate Penalty Include in VOM? ☑	V	(%)	0.53	1175*N/I*100
Aux Power **Include in VOM?** ☑	**O**	**(%)**	**0.05**	0.05 default value
Dilution Water Rate	P	(1000 gph)	2.67	N*0.12/1000
Urea Cost (50% wt solution)	Q	($/ton)	350	<--- User Input
Aux Power Cost	R	($/kWh)	0.06	<--- User Input
Dilution Water Cost	S	($/kgal)	1	<--- User Input
Operating Labor Rate	T	($/hr)	60	<--- User Input (Labor cost including all benefits)
Replacement Coal Cost	U	($/MMBtu)	2	<--- User Input

Costs are all based on 2016 dollars

Capital Cost Calculation		Example		Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty				
BMS ($) =	BT*B*G*220000*(A*H)^0.42; (IF CFB then BT=0.75, ELSE BT=1)	$	2,967,000	SNCR (injectors, blowers, DCS, reagent system) cost
BMA ($) =	IF E ≥ 3 AND F=Bituminous, THEN 69000*(B)*(A*G*H)^0.78, ELSE 0	$	-	Air heater modification / SO3 control (Bituminous only & > 3lb/MMBtu)
BMB ($) =	BT*(L^0.12)*320000*(A)^0.33; (IF CFB then BT=0.75, ELSE BT=1)	$	4,869,000	Balance of plant cost (piping, site upgrades, water treatment for the dilution water, etc…)
BM ($) =	BMS + BMA + BMB	$	7,836,000	Total bare module cost including retrofit factor
BM ($/KW) =			16	Base cost per kW
Total Project Cost				
A1 = 10% of BM		$	784,000	Engineering and Construction Management costs
A2 = 10% of BM		$	784,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$	784,000	Contractor profit and fees
CECC ($) = BM+A1+A2+A3		**$**	**10,188,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) =			**20**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC		$	509,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		$	10,697,000	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =			21	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)		$	-	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1		**$**	**10,697,000**	Total project cost
TPC ($/kW) =			**21**	Total project cost per kW

SNCR Cost Development Methodology

Table 1 Continued

Variable	Designation	Units	Value	Calculation
Boiler Type	BT		Tangential	<--- User Input
Unit Size	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	9800	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.22	<--- User Input
SO2 Rate	E	(lb/MMBtu)	2	<--- User Input
Type of Coal	F		Bituminous	<--- User Input
Coal Factor	G		1	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	H		0.98	C/10,000
Heat Input	I	(Btu/hr)	4.90E+09	A*C*1000
NOx Removal Efficiency	K	(%)	25	
NOx Removed	L	(lb/hr)	270	D*I/10^6*K/100
Urea Rate (100%)	M	(lb/hr)	1172	L/UF/46*30; IF Boiler Type = CFB OR D > 0.3 THEN UF = 0.25; ELSE UF = 0.15
Water Required	N	(lb/hr)	22263	M*19
Heat Rate Penalty Include in VOM? ☑	V	(%)	0.53	1175*N/I*100
Aux Power **Include in VOM?** ☑	**O**	**(%)**	0.05	0.05 default value
Dilution Water Rate	P	(1000 gph)	2.67	N*0.12/1000
Urea Cost (50% wt solution)	Q	($/ton)	350	<--- User Input
Aux Power Cost	R	($/kWh)	0.06	<--- User Input
Dilution Water Cost	S	($/kgal)	1	<--- User Input
Operating Labor Rate	T	($/hr)	60	<--- User Input (Labor cost including all benefits)
Replacement Coal Cost	U	($/MMBtu)	2	<--- User Input

Costs are all based on 2016 dollars

Fixed O&M Cost			
FOMO ($/kW yr) = (No operator time assumed)*2080*T/(A*1000)	$	-	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.012/(B*A*1000)	$	0.19	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.00	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.19**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = M*Q/A/1000	$	0.82	Variable O&M costs for Urea
VOMM ($/MWh) = P*S/A	$	0.01	Variable O&M costs for dilution water
VOMP ($/MWh) = O*R*10	$	0.03	Variable O&M costs for additional auxiliary power required.
VOMB ($/MWh) = 0.001175*N*U/A	$	0.10	Variable O&M costs for heat rate increase due to water injected into the boiler
VOM ($/MWh) = VOMR + VOMM + VOMP + VOMB	**$**	**0.96**	

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Table 2. Example of a Complete Cost Estimate for an SNCR System Installed on a CFB boiler

Variable	Designation	Units	Value	Calculation
Boiler Type	BT		CFB	<--- User Input
Unit Size	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	9800	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.22	<--- User Input
SO2 Rate	E	(lb/MMBtu)	2	<--- User Input
Type of Coal	F		Bituminous	<--- User Input
Coal Factor	G		1	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	H		0.98	C/10,000
Heat Input	I	(Btu/hr)	4.90E+09	A*C*1000
NOx Removal Efficiency	K	(%)	25	
NOx Removed	L	(lb/hr)	270	D*I/10^6*K/100
Urea Rate (100%)	M	(lb/hr)	703	L/UF/46*30; IF Boiler Type = CFB OR D > 0.3 THEN UF = 0.25; ELSE UF = 0.15
Water Required	N	(lb/hr)	13358	M*19
Heat Rate Penalty Include in VOM? ☑	V	(%)	0.32	1175*N/I*100
Aux Power **Include in VOM?** ☑	**O**	**(%)**	**0.05**	0.05 default value
Dilution Water Rate	P	(1000 gph)	1.60	N*0.12/1000
Urea Cost (50% wt solution)	Q	($/ton)	350	<--- User Input
Aux Power Cost	R	($/kWh)	0.06	<--- User Input
Dilution Water Cost	S	($/kgal)	1	<--- User Input
Operating Labor Rate	T	($/hr)	60	<--- User Input (Labor cost including all benefits)
Replacement Coal Cost	U	($/MMBtu)	2	<--- User Input

Costs are all based on 2016 dollars

Capital Cost Calculation		Example		Comments
Includes - Equipment, installation, buildings, foundations, electrical, and retrofit difficulty				
BMS ($) =	BT*B*G*220000*(A*H)^0.42; (IF CFB then BT=0.75, ELSE BT=1)	$	2,225,000	SNCR (injectors, blowers, DCS, reagent system) cost
BMA ($) =	IF E ≥ 3 AND F=Bituminous, THEN 69000*(B)*(A*G*H)^0.78, ELSE 0	$	-	Air heater modification / SO3 control (Bituminous only & > 3lb/MMBtu)
BMB ($) =	BT*(L^0.12)*320000*(A)^0.33; (IF CFB then BT=0.75, ELSE BT=1)	$	3,652,000	Balance of plant cost (piping, site upgrades, water treatment for the dilution water, etc…)
BM ($) =	BMS + BMA + BMB	$	5,877,000	Total bare module cost including retrofit factor
BM ($/KW) =			12	Base cost per kW
Total Project Cost				
A1 = 10% of BM		$	588,000	Engineering and Construction Management costs
A2 = 10% of BM		$	588,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$	588,000	Contractor profit and fees
CECC ($) = BM+A1+A2+A3		**$**	**7,641,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) =			**15**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC		$	382,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		$	8,023,000	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =			**16**	Total project cost per kW without AFUDC
B2 = 0% of (CECC + B1)		$	-	AFUDC (Zero for less than 1 year engineering and construction cycle)
TPC ($) = CECC + B1		**$**	**8,023,000**	Total project cost
TPC ($/kW) =			**16**	Total project cost per kW

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Table 2 Continued

Variable	Designation	Units	Value	Calculation
Boiler Type	BT		CFB	<--- User Input
Unit Size	A	(MW)	500	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Heat Rate	C	(Btu/kWh)	9800	<--- User Input
NOx Rate	D	(lb/MMBtu)	0.22	<--- User Input
SO2 Rate	E	(lb/MMBtu)	2	<--- User Input
Type of Coal	F		Bituminous	<--- User Input
Coal Factor	G		1	Bit=1.0, PRB=1.05, Lig=1.07
Heat Rate Factor	H		0.98	C/10,000
Heat Input	I	(Btu/hr)	4.90E+09	A*C*1000
NOx Removal Efficiency	K	(%)	25	
NOx Removed	L	(lb/hr)	270	D*I/10^6*K/100
Urea Rate (100%)	M	(lb/hr)	703	L/UF/46*30; IF Boiler Type = CFB OR D > 0.3 THEN UF = 0.25; ELSE UF = 0.15
Water Required	N	(lb/hr)	13358	M*19
Heat Rate Penalty Include in VOM? ☑	V	(%)	0.32	1175*N/I*100
Aux Power **Include in VOM?** ☑	**O**	**(%)**	0.05	0.05 default value
Dilution Water Rate	P	(1000 gph)	1.60	N*0.12/1000
Urea Cost (50% wt solution)	Q	($/ton)	350	<--- User Input
Aux Power Cost	R	($/kWh)	0.06	<--- User Input
Dilution Water Cost	S	($/kgal)	1	<--- User Input
Operating Labor Rate	T	($/hr)	60	<--- User Input (Labor cost including all benefits)
Replacement Coal Cost	U	($/MMBtu)	2	<--- User Input

Costs are all based on 2016 dollars

Fixed O&M Cost			
FOMO ($/kW yr) = (No operator time assumed)*2080*T/(A*1000)	$	-	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.012/(B*A*1000)	$	0.14	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.00	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA	**$**	**0.14**	Total Fixed O&M costs
Variable O&M Cost			
VOMR ($/MWh) = M*Q/A/1000	$	0.49	Variable O&M costs for Urea
VOMM ($/MWh) = P*S/A	$	0.00	Variable O&M costs for dilution water
VOMP ($/MWh) = O*R*10	$	0.03	Variable O&M costs for additional auxiliary power required.
VOMB ($/MWh) = 0.001175*N*U/A	$	0.06	Variable O&M costs for heat rate increase due to water injected into the boiler
VOM ($/MWh) = VOMR + VOMM + VOMP + VOMB	**$**	**0.59**	