IPM Model – Updates to Cost and Performance for APC Technologies

CO_2 Reduction Cost Development Methodology

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CO_2 Reduction Cost Development Methodology

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 affect costs, such as flue gas volume and 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 project contingency.

Establishment of the Cost Basis

To establish a basis for carbon dioxide (CO_2) reduction technologies, cost data were collected from the public domain from the DOE/NETL "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Revision 3" and adjusted to reflect retrofit costs rather than those for a facility at a new power plant, based on Sargent & Lundy's (S&L's) experience associated with recent amine-based CO_2 capture processes. S&L also used in-house data reflecting recent CO_2 capture and heat-rate improvement (HRI) projects. All data sources were combined to provide a representative CO_2 reduction cost basis. Due to the limited availability of actual as-spent costs for CO_2 capture projects, the cost estimation tool could not be benchmarked against recently executed projects to confirm how accurately it reflects current market conditions.

A cost algorithm for pre-combustion CO_2 reduction using oxy-combustion technology was not developed. This technology is best reserved for new units, rather than for power plant retrofits. In addition, there are too few examples of retrofits to provide a basis for the costs. Therefore, an algorithm cannot be accurately developed and is not included in the CO_2 reduction technology algorithm. For retrofit applications, the oxy-combustion technology will need to be evaluated on a case-by-case basis to justify its cost competitiveness against the almost commercially demonstrated amine-based capture technology.

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The least-squares curve fit of the data was defined as a "typical" CO_2 capture retrofit for removal of >90% of the inlet CO_2. The typical CO_2 capture retrofit was based on the following:

- Retrofit Difficulty = 1 (average retrofit difficulty);
- Gross Heat Rate = 9,500 Btu/kWh;
- Type of Coal = PRB;
- Project Execution = Multiple lump-sum contracts; and
- Recommended CO_2 emission floor = 90% removal efficiency.

For CO_2 capture, the technology is expected to be applicable to any unit size and, depending how much flue gas is treated, would scale up based on multiple parallel capture trains. However, due to the economy of scale associated with the CO_2 capture processes, only large projects may be economically justified. The cost of piping CO_2 to the nearest Enhanced Oil Recovery (EOR) site is not included in the capital cost algorithm.

Capital cost ranges were used to determine the potential range of CO_2 reduction using HRI methods. For minor CO_2 reduction with HRI, CO_2 capture technology typically is neither applicable to nor cost effective for units smaller than 200 MW.

CO_2 Capture Methodology

Technology Description

The amine-scrubbing process is the most widely studied and used demonstration process for post-combustion CO_2 capture. This process involves passing the flue gas through an absorber column counter-currently with an amine solvent. At low temperatures, the CO_2 is absorbed by the amine solvent and removed from the flue gas. The treated flue gas passes through wash levels prior to exiting the stack. The CO_2-rich solvent leaves the absorber and is heated and regenerated in the stripper column. Steam is typically taken from the unit's existing steam cycle and passed through a reboiler to provide the heat needed to strip the CO_2 from the amine. Once the CO_2 is desorbed from the amine, a concentrated CO_2 stream is dehydrated to remove any moisture and compressed to pipeline quality for transportation.

To limit degradation of the expensive amine solvent, SO_2 and SO_3 emissions must be treated prior to the absorber vessel to lower concentrations of these emissions to less than 2 to 10 ppm. If a unit is not already equipped with flue gas desulfurization (FGD) technology, then it will need to be added. Therefore, capital and operating and maintenance (O&M) costs for a wet FGD (WFGD) which is capable of lowering the SO_2 concentration down to 2-10 ppm should be included as part of the overall CO_2 capture cost. Note that the cost of retrofitting FGD is not included as part of the CO_2 cost algorithm.

CO_2 Reduction Cost Development Methodology

Inputs

Several input variables are required to predict future retrofit costs. The gross unit size in MW and carbon content of the fuel are the major variables for the capital estimation. A retrofit factor that equates to the difficulty in construction of the system must be defined. Note that the costs 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, stripper, compressor, and balance of plant costs.

The CO_2 rate will have the greatest influence on the solvent makeup rate and steam required in the regeneration process. The type of fuel (Bituminous, PRB, or Lignite) will influence the CO_2 quantity in the flue gas because of the differing carbon compositions typical in these types of fuels.

The evaluation includes a user-selected option for identifying if the unit is equipped with FGD. If the unit is not already equipped with FGD technology, costs for installing a WFGD should also be incorporated. The user is required to use the WFGD IPM cost algorithm to generate the capital and O&M costs for the technology.

Any changes from the base assumptions should be incorporated to derive more accurate costs.

Outputs

Total Project Costs (TPC)

First, the installed costs are calculated for each required base module. Note that costs to build a pipeline are not included in this cost algorithm; it is assumed that another entity will be funding the CO_2 pipeline construction. The base module installed costs include the following:

- All equipment,
- Installation,
- Buildings,
- Foundations,
- Electrical, and
- Retrofit difficulty.

These costs can potentially range widely because of the relatively new nature of the process, as well as site-specific details. Capital costs estimated here are expected to encompass a +/- 50% range.

CO_2 Reduction Cost Development Methodology

The base modules are as follows:

BMI =	Base capture island cost
BMC =	Base compression island cost
BMBOP =	Base balance of plant costs including ID or booster fans, new wet chimney, piping, ductwork, foundations, etc.
BM =	BMI + BMC + BMBOP

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

- 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 the following:

- Owner's home office costs (owner's engineering, management, and procurement) are included at 5% of the CECC.
- Allowance for Funds Used During Construction (AFUDC) are included 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, and 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 because all costs are provided in 2016 dollars. The total project cost (TPC) is the sum of the CECC and the additional costs and financing expenditures.

Fixed O&M (FOM)

The fixed O&M cost is a function of the additional operations staff (FOMO), maintenance labor and materials (FOMM), and administrative labor (FOMA) associated with the CO_2 capture installation. The FOM is the sum of the FOMO, FOMM and FOMA.

CO_2 Reduction Cost Development Methodology

The following factors and assumptions underlie calculations of the FOM:

- All the FOM costs were tabulated on a per-kilowatt-year (kW-yr) basis.
- In general, 22 additional shift operators are required for operating the CO_2 capture facility. The FOMO was based on the number of additional operations staff required as a function of generating capacity.
- The fixed maintenance materials and labor factor is a direct function of the process capital cost at 1.5% 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 the following:

- Solvent makeup rates and unit costs,
- Additional power required and unit power cost,
- Loss of production due to steam consumption from the base plant, and
- Makeup water required and unit water cost.

The following factors and assumptions underlie calculations of the VOM:

- All the VOM costs were tabulated on a per-megawatt-hour (MWh) basis.
- The solvent makeup cost is a function of gross unit size, CO_2 rate, and removal efficiency. The capital costs are based on a 90% CO_2 reduction design.
- The additional power required includes increased fan power to account for the added capture island pressure drop and compressor power. This requirement is a function of gross unit size and CO_2 concentration.
- The makeup water rate is a function of gross unit size and CO_2 concentration.
- The transportation, storage, and monitoring costs assume that another entity builds the pipeline to a storage facility.

Because of the widely varying consumption of power, steam, water, and solvent associated with the various CO_2 capture technologies, the variable O&M costs are developed as a fixed amount based on averages of S&L in-house project data and design assumptions.

CO_2 Reduction Cost Development Methodology

Input options are provided so the user can 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 as follows:

- Solvent cost in $/lb; the cost could vary significantly by process supplier;
- Auxiliary power cost in $/kWh;
- Makeup water costs in $/1,000 gallons;
- Operating labor rate (including all benefits) in $/hr; and
- Transportation, storage, and monitoring costs in $/MWh.

The variables that contribute to the overall VOM are shown below:

VOMS =	Variable O&M costs for solvent
VOMTS =	Variable O&M costs for transportation and storage of capture CO_2
VOMP =	Variable O&M costs for additional auxiliary power and steam consumption (lost revenue)
VOMM =	Variable O&M costs for makeup water

The total VOM is the sum of VOMS, VOMTS, VOMP, and VOMM. Table 1 is a complete capital and O&M cost estimate worksheet.

CO_2 Reduction Cost Development Methodology

Table 1. Example of a Complete Cost Estimate for the CO_2 Capture System

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
Type of Coal	D		PRB	<--- User Input
CO2 Capture Rate	E	(ton/hr)	457	A*C*1000*0.9*Coal Rate*10^6 / 2000 (Based on 90% reduction)
SO2 Control Technology	F		None	<--- User Input
Steam Consumption	G	(lb/hr)	1,017,000	2215 * E + 3930
Aux Power	H	(MW)	60	0.14 * E - 4
Makeup Water Rate	I	(gpm)	3703	7.7 *E + 172
Steam Turbine Derate	J	(MW)	73	0.0718 * G / 1000
Net Power Reduction	K	(MW)	133	H + J
Solvent Cost	L	($/lb)	2	<--- User Input
Aux Power Cost	M	($/kWh)	0.03	<--- User Input
Makeup Water Cost	N	($/kgal)	1	<--- User Input
Operating Labor Rate	O	($/hr)	60	<--- User Input (Labor cost including all benefits)
Transportation, Storage, & Monitoring (TS&M)	P	($/MWh)	10	<--- User Input

Costs are all based on 2016 dollars

Capital Cost Calculation			Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, minor physical/chemical wastewater treatment and retrofit difficulty				
BMI ($) =	[370000*(E) + 50000000] * B	$	219,348,000	Base CO2 capture island cost including: Absorbers, strippers, reagent tanks, heat exchangers, etc…
BMC ($) =	[139000*(E) + 20000000] * B	$	83,458,000	Base dehydration and compression cost
BMBOP ($) =	[442000*(E) + 70000000] * B	$	272,282,000	Base balance of plant costs including: ID booster fans, new wet chimney, piping, ductwork, foundations, etc…
BM ($) =	BMI + BMC + BMBOP	$	575,088,000	Total base cost including retrofit factor
BM ($/KW) =			1150	Base cost per kW
Total Project Cost				
A1 = 10% of BM		$	57,509,000	Engineering and Construction Management costs
A2 = 10% of BM		$	57,509,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$	57,509,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$**	**747,615,000**	**Capital, engineering and construction cost subtotal WARNING: Capital cost from WFGD model should be added for project accuracy**
CECC ($/kW) - Excludes Owner's Costs =			**1495**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC		$	37,381,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$**	**784,996,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =			**1570**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)		$	78,500,000	AFUDC (Based on a 3 year engineering and construction cycle)
C1 = 15% of CECC + B1		$	-	EPC fees of 15%
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2		**$**	**863,496,000**	Total project cost
TPC ($/kW) - Includes Owner's Costs and AFUDC =			**1727**	Total project cost per kW

CO_2 Reduction Cost Development Methodology

Table 1 Continued

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
Type of Coal	D		PRB	<--- User Input
CO2 Capture Rate	E	(ton/hr)	457	A*C*1000*0.9*Coal Rate*10^6 / 2000 (Based on 90% reduction)
SO2 Control Technology	F		None	<--- User Input
Steam Consumption	G	(lb/hr)	1,017,000	2215 * E + 3930
Aux Power	H	(MW)	60	0.14 * E - 4
Makeup Water Rate	I	(gpm)	3703	7.7 *E + 172
Steam Turbine Derate	J	(MW)	73	0.0718 * G / 1000
Net Power Reduction	K	(MW)	133	H + J
Solvent Cost	L	($/lb)	**2**	<--- User Input
Aux Power Cost	M	($/kWh)	**0.03**	<--- User Input
Makeup Water Cost	N	($/kgal)	**1**	<--- User Input
Operating Labor Rate	O	($/hr)	**60**	<--- User Input (Labor cost including all benefits)
Transportation, Storage, & Monitoring (TS&M)	P	($/MWh)	**10**	<--- User Input

Costs are all based on 2016 dollars

Fixed O&M Cost

FOMO ($/kW yr) = 22*2080*O/(A*1000)	$	5.49	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.015/(B*A*1000)	$	17.25	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.37	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA + FOMWW	**$**	**23.12**	Total Fixed O&M costs

Variable O&M Cost

VOMS ($/MWh) = L * 1.0 * E / A	$	1.83	Variable O&M costs for solvent
VOMTS ($/MWh) = P	$	10.00	Variable O&M costs for transportation, storage, and monitoring
VOMP ($/MWh) = K * 1000 * M / A	$	7.98	Variable O&M costs for additional auxiliary power and steam required --> Lost Revenue
VOMM ($/MWh) =I * 60 / 1000 * N / A	$	0.44	Variable O&M costs for makeup water
VOM ($/MWh) = VOMS + VOMTS + VOMP + VOMM	**$**	**20.25**	**Total Variable O&M costs WARNING: O&M cost from WFGD model should be added for project accuracy**

CO_2 Reduction Cost Development Methodology

Heat Rate Improvement (HRI) Methodology

Technology Description

The term *HRI* refers to technologies or techniques that can be incorporated at existing power plants to reduce the net unit heat rate. By reducing the total amount of fuel required to generate a specific amount of power, the total CO_2 production decreases as well. As part of the Clean Power Plan, EPA analyzed potential CO_2 emission reductions associated with various "building blocks" that can be used by the power-generating industry. The building blocks include the following: (1) reducing CO_2 emissions (i.e., lb CO_2/MW-net) at individual affected coal-fired electric generating units (EGUs) through HRI; (2) achieving CO_2 emission reductions through re-dispatch from coal-fired units to natural gas combined cycle units; and (3) expanding use of renewable energy resources. The EPA defines HRI as both "best practices" and "upgrades." Although there are many best practices or upgrades a station can undergo to operate more efficiently, this cost algorithm is limited to four of the major options: turbine overhaul, neural network (NN) implementation, air heater in-leakage reduction, and variable-frequency drive (VFD) installation. Note that not all these technologies are applicable on existing units. Unit-by-unit evaluation will be required to determine the suitability of options for and resulting level of HRI.

Turbine Overhaul

Technological advancements with turbine design tools have significantly enhanced the efficiency and longevity of steam turbines. Additionally, fabrication of more geometrically complex components has enabled more efficient designs and facilitated upgrades of older turbines experiencing problems such as steam leakages or blade erosion. For the average vintage turbine, considering loss in performance over time, an upgrade typically would improve long-term average performance by 1 to 3%. However, this technology is not applicable to all units currently in operation, since many vintage turbines have been overhauled or were originally built with a modern blade design.

Neural Network

In general, NN systems tie into a plant's distributed control system (DCS) for data input and control and use plant-specific proprietary modeling and control modules. NN systems are primarily used for burner optimization, HRI, and combustion control to prevent NO_X and CO emission spikes as the plant undergoes rapid load changes. Depending on the complexity of the NN system applied and on the quality of DCS installed at a power plant, NN can improve boiler efficiency by 0 to 1.5%. Many units have already incorporated NN for NO_X control and have generally already achieved HRI through lower excess air and optimized air-to-fuel ratios so cannot further optimize the boiler operation for HRI without sacrificing NO_X reduction.

Air Heater In-Leakage

Air leakage from the higher-pressure, cold pre-combustion air side of a new-design air pre-heater to its hot flue gas side typically ranges from 5 to 7% of total air flow, however, after prolonged operation leakages could increase up to 20%. Generally, combustion air leaks across the faces of the rotating cylinder or around the outer perimeter of the cylinder. As a unit ages and seals deteriorate, air leakage increases, which lowers plant efficiency by harming boiler performance due to lost heat recuperation and by adversely affecting fan performance due to the increased air flow to the FD fans to maintain sufficient O_2 levels in the boiler. This increased air flow raises the auxiliary power consumption of the FD and ID fans to transfer the extra air through the flue gas ductwork, emissions control equipment, and stack. Improved seals on the sectors, outer perimeter, and rotor section of regenerative air pre-heaters can reduce air leakage back to design rates and lower heat rate by up to 0.5%. However, many units already employ best operation and maintenance practices with their air-heater seals, thereby negating further HRI.

VFDs

Under current electricity market conditions with reduced demand, many units no longer operate at base-load capacity. Therefore, VFDs installed on large motors can greatly enhance plant performance at off-peak loads and as loads vary throughout the year. When VFDs are used, plant auxiliary power associated with fans can be reduced by approximately 30% during load turndown. Depending on plant configuration, VFDs can improve heat rate up to 1%, with cycling units experiencing improvements at the upper range and base-load units at the lower range; however, they can also have no significant impact. VFD use is most applicable to damper- or vane-controlled centrifugal fans that operate on non-baseload units; therefore, the full range of HRI is not always applicable to each unit. Additionally, many units have already incorporated this technology during air quality control technology implementation (such as during FGD or SCR installations) and, therefore, can no longer gain any improvement in efficiency.

Inputs

Several unit-specific variables are required to predict the potential future heat-rate reduction and retrofit costs. Since many of these technologies have already been incorporated, a unit-specific study must be performed to determine which technologies are applicable and to what extent. Items such as fuel, unit size/type, air quality control system equipment, and other site-specific limitations can have a dramatic impact on the overall future efficiency improvement and subsequent CO_2 reduction.

Outputs

Capital Costs

The installed-cost equations are provided for each optional module. The base modules are turbine overhaul, NN implementation, air heater in-leakage reduction, and VFDs installed on large motors. Adding the module costs will generate the total project cost, excluding any indirect costs. However, as noted before, not all the modules will be applicable, and, therefore, no cost would be included for those modules that are not applicable.

O&M

O&M cost equations are estimated for each HRI technology, based on maintenance equipment and materials, additional operators, and changes to auxiliary power consumption. However, since a reduction in heat rate will provide lower fuel consumption, fuel cost savings may negate the O&M costs for the HRI technologies. Due to fuel-cost specifics and baseline heat input, these costs should be calculated on a unit-specific basis.

CO_2 Reduction

Many times, all four technologies are not applicable to a specific unit. Thus, due to the unit-specific nature of each HRI modification, a range of potential heat-rate reduction or CO_2-reduction percentages are provided. Also, note that HRI rates are not strictly additive; often, implementation of many projects at one time will provide a prorated efficiency improvement. Based on S&L's experience, it is likely in most cases that 0 to 3% HRI and subsequent CO_2 reduction may be feasible. Table 2 provides an example of a complete cost estimate for HRI projects.

Table 2. Example of a Complete Cost Estimate for HRI Projects

HRI Technologies	Capital Cost ($)	O&M Cost ($/yr)	CO_2 Reduction (%)
Turbine Overhaul	$25 \times \left(\frac{MW}{300}\right)^{0.2} \times 10^6$	--	**1-3**
Neural Network	$500,000 \times \left(\frac{MW}{300}\right)^{0.4}$	$100,000 \times \left(\frac{MW}{300}\right)^{0.4}$	**0-1.5**
Air Heater In-Leakage	$[2-6] \times \left(\frac{MW}{300}\right)^{0.8} \times 10^6$	$100,000 \times \left(\frac{MW}{300}\right)^{0.8}$	**0-0.5**
VFDs	$3.2 \times \left(\frac{MW}{300}\right)^{0.6} \times 10^6$	$100,000 \times \left(\frac{MW}{300}\right)^{0.6}$	**0-1**