IPM Model – Updates to Cost and Performance for APC Technologies

CO_2 Reduction Retrofit Cost Development Methodology

Final

March 2023

Project 13527-002

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LEGAL NOTICE

This work was funded by the U.S. Environmental Protection Agency (EPA) through Eastern Research Group, Inc. (ERG) as a contractor and reviewed by ERG and EPA personnel.

CO_2 Reduction Retrofit 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 retrofit of carbon dioxide (CO_2) reduction technologies, cost data were collected from the public domain and Sargent & Lundy's (S&L's) recent experience associated with recent amine-based CO_2 capture processes implemented as retrofits to power facilities. 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. While the coal-fired applications utilize a robust amount of data sources, from feasibility and FEED studies, it is only recently that feasibility and FEED studies have been completed for NGCC applications of this technology. As such, cost multipliers are used to compare coal-fired capital cost pricing to NGCC applications.

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 = 10,000 Btu/kWh;
- Type of Coal = PRB;
- Project Execution = Engineer, Procurement, and Construction (EPC) contracts; and
- Typical CO_2 capture rate = 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. Transportation, storage, and monitoring (TS&M) of the captured CO_2 are not included in the base cost estimates and instead costs can be included as a user input on a $/ton basis.

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. 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 and/or sequestration. 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. While certain applications justify the use of new natural gas auxiliary boilers for steam production, this module is based solely on steam extraction, to avoid additional emissions associated with additional fuel combustion.

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 Retrofit 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 or sites with limited adjacent space. One example for the use of a retrofit factor is if a facility needs to minimize additional water consumption. For cases where a hybrid cooling system is required due to limited water availability, a retrofit factor of 1.15 should be used to account for the increase in the capital cost associated with that system.

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. Heat rate is an input from the user, with a suggested starting point of 10,000 Btu/kWh for coal-fired boilers, and 6,660 Btu/kWh for natural gas combined cycle (NGCC) facilities.

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, Lignite, or Natural Gas) 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 fires coal and 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.

CO_2 Reduction Retrofit Cost Development Methodology

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.
The base modules are as follows:

BMI =	Base capture island cost, including compression
BMBOP =	Base balance of plant costs including piping, ductwork, cooling system, steam integration, foundations, etc.
BM =	BMI + BMBOP

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

- Engineering and construction management costs at 15% 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 turnkey engineering, procurement, and construction (EPC) contract execution; as such, the total project cost is increased by 15% to account for risk and fees associated with this structure.

Escalation is not included in the estimate because all costs are provided in 2021 dollars and are not representative of recent COVID and inflation related pricing increases. The total project cost (TPC) is the sum of the CECC and the additional costs and financing expenditures.

CO_2 Reduction Retrofit Cost Development Methodology

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.
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 2.5% of the equivalent equipment and material portion, which is expected to be 60% 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.
- A VOM related calculations are estimated using different equations for NGCC and coal-fired applications.
- The solvent makeup cost is a function of total CO_2 captured. The capital costs are based on a 90% CO_2 reduction design. An indicative value is included but can be adjusted by the user.
- The steam derate is estimated based on the steam extracted for use in the CO_2 regeneration process. Steam rate is a function of total CO_2 captured.
- The additional power required includes increased fan power to account for the added capture island pressure drop, system pumps, and compressor power. This requirement is a function of total CO_2 captured.
- The makeup water rate is a function of total CO_2 captured.

CO_2 Reduction Retrofit Cost Development Methodology

- The transportation, storage, and monitoring costs are not included. A cost can be added by the user, based on an evaluated cos with respect to the amount of CO_2 captured in ton.

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, calculated separately for coal-fired or NGCC applications. Steam turbine derate is not calculated separately, as the derate is expected to be similar based on total steam extraction, regardless of application.

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 $/ton of CO_2 captured; 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 $/ton.

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 Retrofit Cost Development Methodology

Table 1. Example 1 (Coal)

Fill in the yellow cells with the known data inputs. The resulting costs are tabulated below. Variable names are defined as outlined in the table.

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	700	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	10000	<--- User Input (Default Coal-Fired = 10,000; NGCC = 6,660)
Type of Fuel	D		PRB	<--- User Input
CO2 Capture Rate	E	(ton/hr)	674	A*C*1000*0.9*Coal Rate /10^6 / 2000 (Based on 90% reduction)
SO2 Control Technology	F		FGD	<--- User Input
Steam Consumption	G	(lb/hr)	1,590,900	Coal: 1.18 * E * 2000 ; NGCC: 1.33 * E * 2000
Aux Power	H	(MW)	99	Coal: 0.1465 * E ; NGCC: 0.207 * E
Makeup Water Rate	I	(gpm)	4894	Coal: 7.26 * E ; NGCC: 9.73 * E
Steam Turbine Derate	J	(MW)	123	0.155 * G / 2000
Net Power Reduction	K	(MW)	222	H + J
Solvent Cost	L	($/ton CO2 removed)	3.5	<--- User Input
Aux Power Cost	M	($/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	($/ton)	10	<--- User Input

Costs are all based on 2021 dollars

Capital Cost Calculation		Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, minor physical/chemical wastewater treatment and retrofit difficulty			
BMI ($) = +B24:L34BI	Coal: [883000*(E)] * B ; NGCC: [883000*(E)] * B * 1.45	$ 595,230,000	Base CO2 capture island cost including: Absorbers and stacks, strippers, blowers, reagent tanks, heat exchangers, compressors, etc…
BMBOP ($) =	Coal: [235200*(E)] * B ; NGCC: [235200*(E)] * B * 1.45	$ 158,548,000	Base balance of plant costs including: Cooling system, steam supply, piping, ductwork, foundations, etc…
BM ($) =	BMI + BMC + BMBOP	$ 753,778,000	Total base cost including retrofit factor
BM ($/KW) =		1077	Base cost per kW
Total Project Cost			
A1 = 15% of BM		$ 113,067,000	Engineering and Construction Management costs
A2 = 10% of BM		$ 75,378,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$ 75,378,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$ 1,017,601,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**1454**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC		$ 50,880,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$ 1,068,481,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**1526**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)		$ 106,848,000	AFUDC (Based on a 3 year engineering and construction cycle)
C1 = 15% of CECC + B1		$ 168,667,000	EPC G&A and risk fees of 15%
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2		**$ 1,175,329,000**	Total project cost
TPC ($/kW) - Includes Owner's Costs and AFUDC =		**1679**	Total project cost per kW

CO_2 Reduction Retrofit Cost Development Methodology

Table 1. Example 1 (Coal) Continued

Fill in the yellow cells with the known data inputs. The resulting costs are tabulated below. Variable names are defined as outlined in the table.

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	700	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	10000	<--- User Input (Default Coal-Fired = 10,000; NGCC = 6,660)
Type of Fuel	D		PRB	<--- User Input
CO2 Capture Rate	E	(ton/hr)	674	A*C*1000*0.9*Coal Rate /10^6 / 2000 (Based on 90% reduction)
SO2 Control Technology	F		FGD	<--- User Input
Steam Consumption	G	(lb/hr)	1,590,900	Coal: 1.18 * E * 2000 ; NGCC: 1.33 * E * 2000
Aux Power	H	(MW)	99	Coal: 0.1465 * E ; NGCC: 0.207 * E
Makeup Water Rate	I	(gpm)	4894	Coal: 7.26 * E ; NGCC: 9.73 * E
Steam Turbine Derate	J	(MW)	123	0.155 * G / 2000
Net Power Reduction	K	(MW)	222	H + J
Solvent Cost	L	($/ton CO2 removed)	3.5	<--- User Input
Aux Power Cost	M	($/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	($/ton)	10	<--- User Input

Costs are all based on 2021 dollars

Fixed O&M Cost			
FOMO ($/kW yr) = 22*2080*O/(A*1000)	$	3.92	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.6*0.025/(B*A*1000)	$	16.15	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.31	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA + FOMWW	**$**	**20.39**	Total Fixed O&M costs
Variable O&M Cost			
VOMS ($/MWh) = L * E / A	$	3.37	Variable O&M costs for solvent
VOMTS ($/MWh) = P * E / A	$	9.63	Variable O&M costs for transportation, storage, and monitoring
VOMP ($/MWh) = K * 1000 * M / A	$	9.51	Variable O&M costs for additional auxiliary power and steam required --> Lost Revenue
VOMM ($/MWh) =I * 60 / 1000 * N / A	$	0.42	Variable O&M costs for makeup water
VOM ($/MWh) = VOMS + VOMTS + VOMP + VOMM	**$**	**22.93**	Total Variable O&M costs

Annual Capacity Factor =	0.85	
Annual MWhs =	5,212,200	
Annual Heat Input MMBtu =	52,122,000	
Annual Ton CO2 Created =	5,577,054	
Annual Ton CO2 Removed =	5,019,349	at removal efficiency = 90%
Annual Ton CO2 Emission =	557,705	
Annual Avg CO2 Emission Rate, lb/MWh =	214	based on original gross unit load [A]

Annual Capital Recovery Factor =	0.082	
	CO2 Capture	*from DOE 2019 BBS 12B*
Annual Capital Cost (Including AFUDC), $ =	96,377,000	
Annual FOM Cost, $ =	14,270,000	
Annual VOM Cost, $ =	119,535,000	
Total Annual CO2 Capture Cost, $ =	230,182,000	

Capital Cost, $/MWh =	18.49
FOM Cost, $/MWh =	2.74
VOM Cost, $/MWh =	22.93
Total CO2 Capture Cost, $/MWh =	44.16

Capital Cost, $/ton =	19
FOM Cost, $/ton =	3
VOM Cost, $/ton =	24
Total CO2 Capture Cost, $/ton =	46

CO_2 Reduction Retrofit Cost Development Methodology

Table 2. Example 1 (NGCC)

Fill in the yellow cells with the known data inputs. The resulting costs are tabulated below. Variable names are defined as outlined in the table.

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	700	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	6660	<--- User Input (Default Coal-Fired = 10,000; NGCC = 6,660)
Type of Fuel	D		NGCC	<--- User Input
CO2 Capture Rate	E	(ton/hr)	245	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)	652,900	Coal: 1.18 * E * 2000 ; NGCC: 1.33 * E * 2000
Aux Power	H	(MW)	51	Coal: 0.1465 * E ; NGCC: 0.207 * E
Makeup Water Rate	I	(gpm)	2388	Coal: 7.26 * E ; NGCC: 9.73 * E
Steam Turbine Derate	J	(MW)	51	0.155 * G / 2000
Net Power Reduction	K	(MW)	102	H + J
Solvent Cost	L	($/ton CO2 removed)	3.5	<--- User Input
Aux Power Cost	M	($/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	($/ton)	10	<--- User Input

Costs are all based on 2021 dollars

Capital Cost Calculation		Example	Comments
Includes - Equipment, installation, buildings, foundations, electrical, minor physical/chemical wastewater treatment and retrofit difficulty			
BMI ($) = +B24:L34BI	Coal: [883000*(E)] * B ; NGCC: [883000*(E)] * B * 1.45	$ 314,267,000	Base CO2 capture island cost including: Absorbers and stacks, strippers, blowers, reagent tanks, heat exchangers, compressors, etc…
BMBOP ($) =	Coal: [235200*(E)] * B ; NGCC: [235200*(E)] * B * 1.45	$ 83,710,000	Base balance of plant costs including: Cooling system, steam supply, piping, ductwork, foundations, etc…
BM ($) =	BMI + BMC + BMBOP	$ 397,977,000	Total base cost including retrofit factor
BM ($/KW) =		569	Base cost per kW
Total Project Cost			
A1 = 15% of BM		$ 59,697,000	Engineering and Construction Management costs
A2 = 10% of BM		$ 39,798,000	Labor adjustment for 6 x 10 hour shift premium, per diem, etc…
A3 = 10% of BM		$ 39,798,000	Contractor profit and fees
CECC ($) - Excludes Owner's Costs = BM+A1+A2+A3		**$ 537,270,000**	Capital, engineering and construction cost subtotal
CECC ($/kW) - Excludes Owner's Costs =		**768**	Capital, engineering and construction cost subtotal per kW
B1 = 5% of CECC		$ 26,864,000	Owners costs including all "home office" costs (owners engineering, management, and procurement activities)
TPC' ($) - Includes Owner's Costs = CECC + B1		**$ 564,134,000**	Total project cost without AFUDC
TPC' ($/kW) - Includes Owner's Costs =		**806**	Total project cost per kW without AFUDC
B2 = 10% of (CECC + B1)		$ 56,413,000	AFUDC (Based on a 3 year engineering and construction cycle)
C1 = 15% of CECC + B1		$ 89,052,000	EPC G&A and risk fees of 15%
TPC ($) - Includes Owner's Costs and AFUDC = CECC + B1 + B2		**$ 620,547,000**	Total project cost
TPC ($/kW) - Includes Owner's Costs and AFUDC =		**886**	Total project cost per kW

CO_2 Reduction Retrofit Cost Development Methodology

Table 2. Example 2 (NGCC) Continued

Fill in the yellow cells with the known data inputs. The resulting costs are tabulated below. Variable names are defined as outlined in the table.

Variable	Designation	Units	Value	Calculation
Unit Size (Gross)	A	(MW)	700	<--- User Input
Retrofit Factor	B		1	<--- User Input (An "average" retrofit has a factor = 1.0)
Gross Heat Rate	C	(Btu/kWh)	6660	<--- User Input (Default Coal-Fired = 10,000; NGCC = 6,660)
Type of Fuel	D		NGCC	<--- User Input
CO2 Capture Rate	E	(ton/hr)	245	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)	652,900	Coal: 1.18 * E * 2000 ; NGCC: 1.33 * E * 2000
Aux Power	H	(MW)	51	Coal: 0.1465 * E ; NGCC: 0.207 * E
Makeup Water Rate	I	(gpm)	2388	Coal: 7.26 * E ; NGCC: 9.73 * E
Steam Turbine Derate	J	(MW)	51	0.155 * G / 2000
Net Power Reduction	K	(MW)	102	H + J
Solvent Cost	L	($/ton CO2 removed)	3.5	<--- User Input
Aux Power Cost	M	($/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	($/ton)	10	<--- User Input

Costs are all based on 2021 dollars

Fixed O&M Cost			
FOMO ($/kW yr) = 22*2080*O/(A*1000)	$	3.92	Fixed O&M additional operating labor costs
FOMM ($/kW yr) = BM*0.6*0.025/(B*A*1000)	$	8.53	Fixed O&M additional maintenance material and labor costs
FOMA ($/kW yr) = 0.03*(FOMO+0.4*FOMM)	$	0.22	Fixed O&M additional administrative labor costs
FOM ($/kW yr) = FOMO + FOMM + FOMA + FOMWW	**$**	**12.67**	Total Fixed O&M costs
Variable O&M Cost			
VOMS ($/MWh) = L * E / A	$	1.23	Variable O&M costs for solvent
VOMTS ($/MWh) = P * E / A	$	3.51	Variable O&M costs for transportation, storage, and monitoring
VOMP ($/MWh) = K * 1000 * M / A	$	4.37	Variable O&M costs for additional auxiliary power and steam required --> Lost Revenue
VOMM ($/MWh) =I * 60 / 1000 * N / A	$	0.21	Variable O&M costs for makeup water
VOM ($/MWh) = VOMS + VOMTS + VOMP + VOMM	**$**	**9.31**	Total Variable O&M costs

Annual Capacity Factor =	0.85	
Annual MWhs =	5,212,200	
Annual Heat Input MMBtu =	34,713,252	
Annual Ton CO2 Created =	2,030,725	
Annual Ton CO2 Removed =	1,827,653	at removal efficiency = 90%
Annual Ton CO2 Emission =	203,073	
Annual Avg CO2 Emission Rate, lb/MWh =	78	based on original gross unit load [A]

Annual Capital Recovery Factor =	0.082	CO2 Capture	*from DOE 2019 BBS 12B*
Annual Capital Cost (Including AFUDC), $ =		50,885,000	
Annual FOM Cost, $ =		8,869,000	
Annual VOM Cost, $ =		48,527,000	
Total Annual CO2 Capture Cost, $ =		108,281,000	

Capital Cost, $/MWh =	9.76
FOM Cost, $/MWh =	1.70
VOM Cost, $/MWh =	9.31
Total CO2 Capture Cost, $/MWh =	20.77

Capital Cost, $/ton =	28
FOM Cost, $/ton =	5
VOM Cost, $/ton =	27
Total CO2 Capture Cost, $/ton =	59

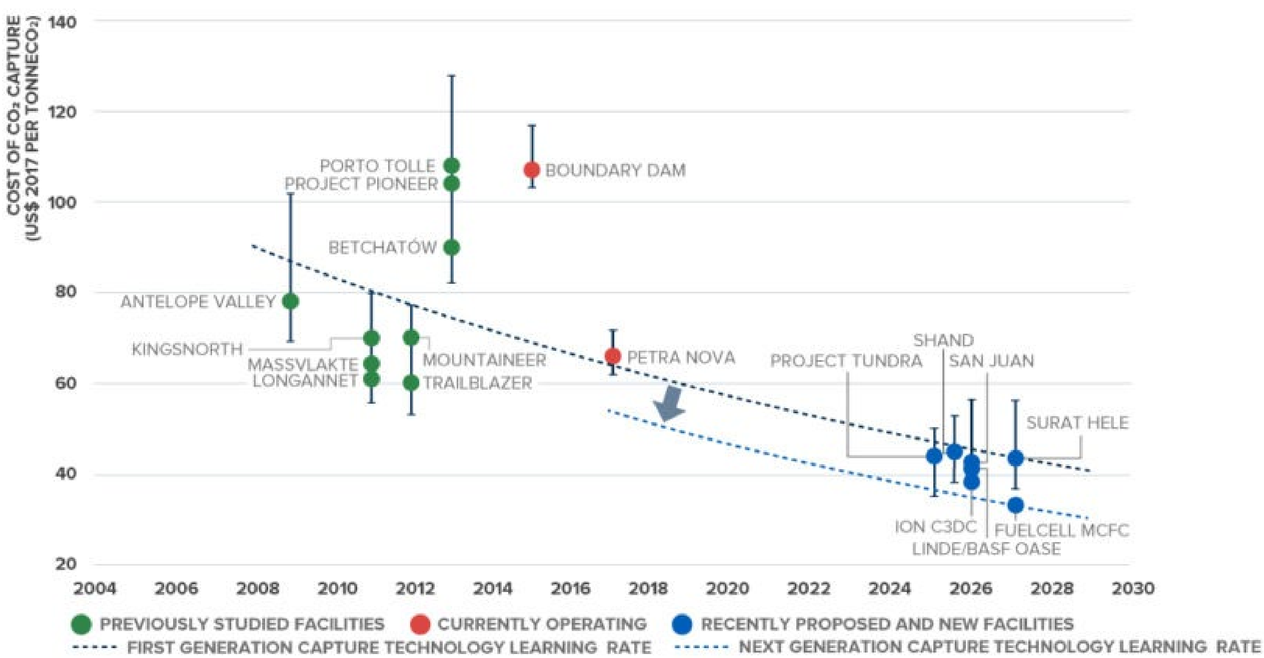
Appendix A – Amine Capture Cost Comparison

HISTORICAL PERSPECTIVE

Post-combustion CO_2 capture technology has been developed and advanced on power plant applications over the last few decades. With two large-scale applications installed in North America on coal-fired power plants, post-combustion amine-based capture has been proven to be a technically feasible technology to implement. In the last five years, since the Petra Nova project, the U.S. Department of Energy (DOE) has actively engaged various amine-solvent technology suppliers to conduct front-end, engineering and design (FEED) studies to advance the technology and further refine and reduce the overall cost of capture.

The Global CCS Institute has tracked publicly available information on previously studied, executed, and proposed CO_2 capture projects. Recent pricing is approximately $40/tonne ($36/ton) on average for coal plants (excluding transportation, storage, and monitoring), compared to Petra Nova and Boundary Dam whose actual costs were reported to be $65 and $105/tonne ($59 and $95/ton), respectively, see Figure 1.[1]

Figure 1 — Levelized Cost of CO_2 Capture for Large Scale Post-Combustion Facilities at Coal-Fired Power Plants



Sections below discuss high-level cost comparisons for the application of amine-based CO_2 capture system considering retrofit vs. new application on both coal and NGCC facilities.

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[1] Global Status of CCS 2019: Targeting Climate Change. Figure 8.
https://ccsknowledge.com/pub/Publications/Global_Status%20of_CCS_2019%20_GCCSI.pdf

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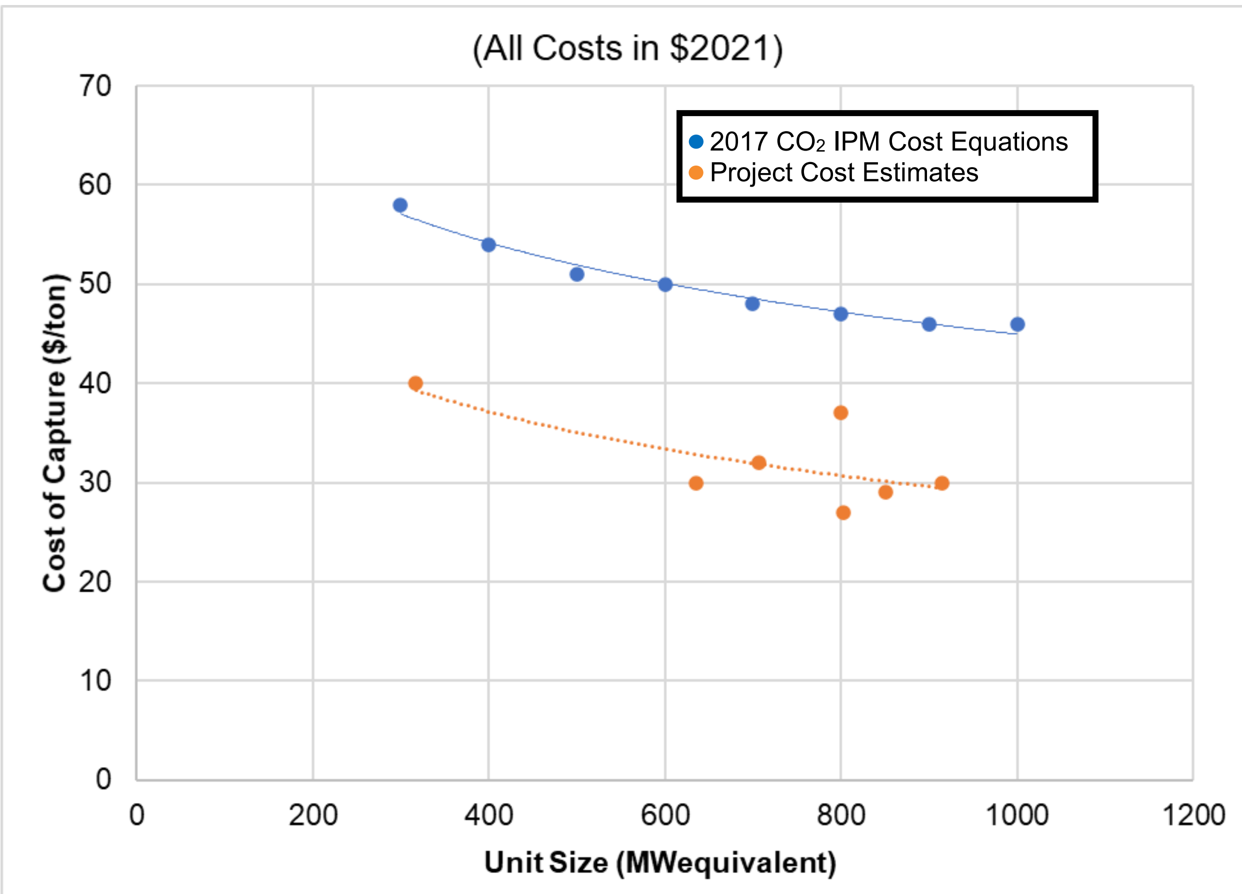
RETROFIT COST COMPARISON

In 2016, S&L developed a model to predict the cost to retrofit and operate a CO_2 capture system at existing coal-fired power plants. Since that time, cost of capture has come down incrementally, based on recent project feasibility and FEED studies. S&L compared recent project estimates from 2020-2021 to the "IPM Model – Updates to Cost and Performance for APC Technologies, CO_2 Reduction Cost Development Methodology" dated Final, February, 2017 (referred to as "2017 CO_2 IPM Cost Equations"), as shown in Figure 2. The 2017 CO2 IPM Cost Equations were developed and applied to coal-fired applications only. Based on the advancements within the industry in terms of optimization of energy demand, solvent makeup costs, financing costs, and lessons learned from pilot facilities, all recent project costs for coal-fired retrofits are noticeably lower than the original curve, by approximately 20%[2].

Figure 2 —Recent Project Cost Estimate Comparison to 2017 CO_2 IPM Cost Equations



Depending on the approach for implementing CO_2 capture, the cost of capture for coal-fired units is generally in the range of \$30-50/tonne (\$27-45/ton).[3] The reduction in costs is due primarily to technology innovations

[2] For this evaluation all costs are representative of 2021 dollars and excludes current market conditions; all other default parameters in the IPM model were held constant. This comparison excludes any cost of transportation, storage, and monitoring (TS&M). In 2022, inflation has resulted in an increase of CO_2 capture system costs of 15-20% on average; however, this continues to fluctuate.

[3] For this evaluation all costs are representative of 2021 dollars and excludes current market conditions. The cost of capture excludes costs related to transportation, storage, and monitoring (TS&M).

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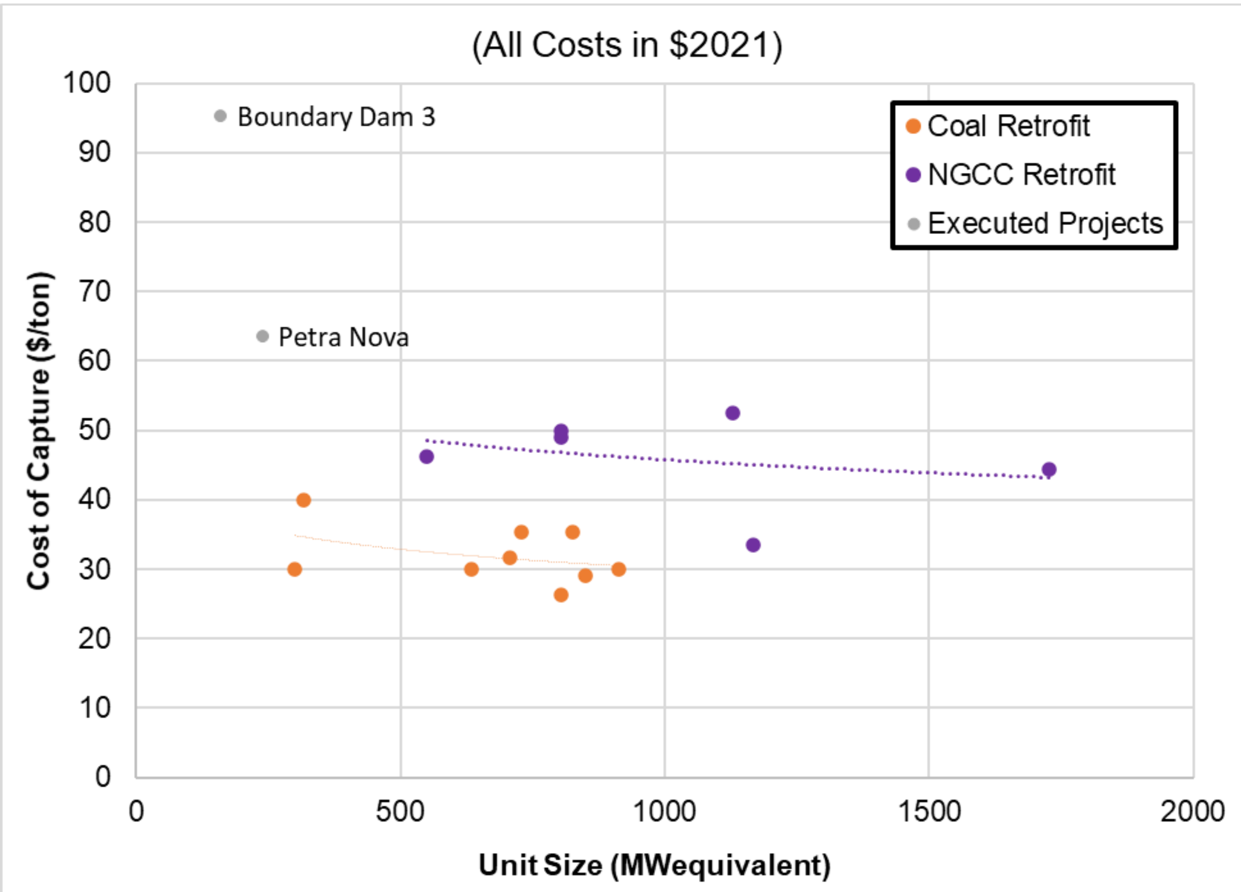
and lessons learned from implemented projects.

Amine CO_2 capture technology suppliers have made advancements in their solvent and process design that allows for better capture of CO_2 at low partial pressures. With these considerations, S&L has seen a large reduction in overall cost of capture for NGCC facilities recently, however, there are still limitations to the technology and overall economics. As seen in Figure 3, costs estimated for application of CO_2 capture at a NGCC facility are significantly higher on an evaluated cost ($/tonne or $/ton) than on a coal-fired facility, approximately 50%, due to economies of scale and CO_2 concentration.

Figure 3 — CO_2 Capture Retrofit Costs on Coal-Fired v. NGCC Units



NEW FACILITY COST COMPARISON

The cost of CO_2 capture implementation constructed in parallel with new units is expected to be on the lower end of the cost ranges provided in the previous sections, as the arrangement, design, and integration with the base facility will be optimized. If new NGCC units are built with CO_2 capture, the capacity factor can be expected to be relatively high, similar to a base loaded facility (e.g. ≥85%); this also improves the overall capture economics. However, as in retrofit applications, the costs estimated for application of CO_2 capture at a new NGCC facility are significantly higher on an evaluated cost ($/tonne or $/ton) than on a coal-fired facility.

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Table 1: Comparative Cost of Capture

Coal w/ Carbon Capture-90%	Units	New Unit ATB2021	New Unit EIA - S&L	S&L Retrofit Experience
Gross Unit Size	MW	Not specified	831	700
Net Nominal Capacity	MW	650	650	455
Net Nominal Heat Rate	Btu/kWh	10,830	12,507	14,776
CO_2 Emission Rate	lb/MMBtu	20.23	20.60	21.10
Capital Cost[1,2]	$/kW-net	$4,698	$5,876	$3,202
Fixed O&M Cost[1]	$/kW-year	$122.00	$59.54	$41.27
Variable O&M Cost[1,6]	$/MWh	$14.00	$10.98	$21.94
Fuel O&M Cost[5]	$/MWh-net	$24.12	$27.85	$0.00
Cost of Capture[3,4]	$/tonne	$39.08	$39.31	$48.81
	$/ton	$35.45	$35.65	$44.27
NGCC w/ Carbon Capture-90%	**Units**	**New Unit ATB2021**	**New Unit EIA - S&L**	**S&L Retrofit Experience**
Frame Type	---	Not specified	H-Class, 1x1x1	F-Class, 3x1
Net Nominal Capacity	MW	646	377	632
Net Nominal Heat Rate	Btu/kWh	7,160	7,124	9047
CO_2 Emission Rate	lb/MMBtu	11.86	11.70	11.5
Capital Cost[1,2]	$/kW-net	$2,435	$2,481	$1,267
Fixed O&M Cost[1]	$/kW-net-year	$65.00	$27.60	$21.64
Variable O&M Cost[1,6]	$/MWh-net	$6.00	$5.84	$8.29
Fuel O&M Cost[5]	$/MWh-net	$31.65	$31.49	$0.00
Cost of Capture[3,4]	$/tonne	$82.28	$68.24	$58.50
	$/ton	$74.63	$61.89	$53.06

Notes:

[1]All cost values in 2019 dollars, 2019 Case shown for ATB2021.
[2]All capital cost values are presented as overnight costs.
[3]Assumed capacity factor of 85%.
[4]Assumed evaluation period of 20 years and 5.0% interest rate.
[5] All cases have fuel O&M costs added using NETL assumptions ($51.96/ton coal, 11,666 Btu/lb coal; $4.42/MMBtu gas, 22,483 Btu/lb gas); for retrofit case, no additional fuel usage is expected.
[6]All steam turbine and aux power derate for the retrofit cases are accounted for within the variable O&M.

Note that there are many different assumptions considered in the EIA and the example retrofit evaluations making this difficult to compare on a line by line basis. Unit derate costs due to steam turbine derates or additional aux power demand due to carbon capture are typically covered in the variable O&M (VOM) costs; in this case, the retrofit VOM is noticeably higher than the new unit VOM. Instead of including derates for the new unit in VOM, it is covered separately in the EIA evaluation as part of fuel-based O&M costs. When reviewing retrofit cases, often times property tax, insurance, and administrative impacts are excluded from the fixed O&M (FOM) costs since the facility is expected to absorb that cost. While the retrofit cases suggest that the FOM is lower, in reality, FOM costs for all four cases would be expected to be similar.