Appendix A: CCS Costs

This appendix describes the costs for CCS on coal and gas plants developed for modeling by the Clean Air Task Force (CATF) and compares them to CCS costs used in IPM platform v6.

Coal CCS Retrofit Costs

The Petra Nova approach to retrofitting the W.A. Parish coal plant with CCS relied on providing a *separate* source of electricity and steam for the capture unit. Petra Nova opted to build a 75 MW natural gas-fired cogeneration (cogen) unit that supplied 35 MW - 40 MW of electricity to the grid while also providing as much as 40 MW of electricity and steam to the capture unit.[1] A cogen unit simplifies the process of installing and using CCS retrofits because it is less disruptive to the coal plant. The combustion characteristics of the base coal plant do not change, and the specific steam needs of the capture unit can be matched to the cogen plant.[2]

CATF developed CCS costs for a variant of the Petra Nova approach for use in modeling as shown in the tables below. In the CATF approach, steam (but not electricity) is provided to the capture unit by a standalone gas-fired auxiliary boiler. Electricity for the capture unit is assumed to come from the base coal plant. This reduces the plants electricity sales by the auxiliary load needed to run compressors and other systems in the post-combustion capture unit. However, because steam comes from a standalone gas boiler, the heat rate of the coal plant is unchanged. The costs of providing gas to the capture unit are calculated at 2.77 MMBtu of natural gas/ton of CO_2 captured X the gas price in $/MMBtu.[3] Capital costs, variable operations and maintenance (VOM), fixed operations and maintenance (FOM) and auxiliary loads were developed and adapted from previous CATF work[4] and consultations with industry suppliers.

Coal Retrofits (200 MW)

[1] "Petra Nova and the Future of Carbon Capture" presented at DOE/NARUC Carbon Capture, Storage & Utilization Partnership Webinar Summary, (Mar, 23, 2017), https://www.naruc.org/default/assets/File/Petra%20Nova%20Surge%20Summary%203_23_17.pdf.

[2] Anthony Armpriester & Ted McMahon, "World's Largest Post-combustion Carbon Capture Project Nearing Completion," Power Engineering (Dec. 22, 2016), https://www.power-eng.com/articles/print/volume-120/issue-12/features/petra-nova.html

[3] MHI, "CO2 Recovery Plants: Process Flow," https://www.mhi.com/products/environment/carbon_dioxide_recovery_process_flow.html (Assumed boiler efficiency of 87.5% and 1.3 tons of steam/ton of CO_2 captured).

[4] For a general overview of the costing approach for integrated systems, *see* Appendix A from CATF's comments on the Clean Power Plan, *available at*: http://www.catf.us/resources/filings/EGU_GHG_NSPS_Rule/CCS%20Assumptions%20Appendix%20A.pdf. CATF adapted the 90% carbon capture level coal plant data found in Table 1 for capital costs, FOM and VOM. Costs for the auxiliary boiler were provided by industry sources.

Technology	Low Heat rate	Moderate Heat Rate	High Heat Rate
Heat Rate (Btu/kWh)	9500	10500	11500
Incremental Capital cost ($2017 / kW)	$1,952.00	$2097.00	$2240.00
FOM ($2017/kw-yr)	$27.84	$29.91	$31.95
VOM ($2017/MWh)	$3.13	$3.36	$3.58
CCS Load (MW)	16.83	18.60	20.37
Lbs captured per MWh net	1913.76	2135.86	2362.34
Lbs emitted per MWh net	522.75	583.42	645.29

Coal Retrofits (400 MW)

Technology	Low Heat rate	Moderate Heat Rate	High Heat Rate
Heat Rate (Btu/kWh)	9500	10500	11500
Incremental Capital cost ($2017 / kW)	$1,501.00	$1613.00	$1,724.00
FOM ($2017/kw-yr)	$21.40	$23.00	$24.59
VOM ($2017/MWh)	$2.37	$2.54	$2.71
CCS Load (MW)	33.65	37.20	40.74
Lbs captured per MWh net	1913.76	2135.86	2362.34
Lbs emitted per MWh net	522.75	583.42	645.29

CATF's costs assume Nth-of-a-kind (NOAK) costs where N is at least 5. CATF assumed that the post-combustion capture approach would be implemented in modules of about 400 MW. This size has several advantages. First, some coal plants cycle and turn down at night. On a larger coal plant, 400 MW may be close to the turn down capacity of the plant. If the plant pursues a partial capture retrofit, the capture unit could still run at full capacity 24 hours per day, although the plant would vent some CO_2 during the day that exceeded the capture unit's capacity. Also, this module size is similar to the fully demonstrated size at Petra Nova. The table allows smaller units to be built, but some economies of scale are reflected in the larger size. Beyond 400 MW, CATF assumed that the full capture approach would be implemented in modules. To illustrate, a 400 MW coal plant would have one CCS post-combustion module, while a 800 MW plant would have two modules. In contrast to an approach that sought to exploit economies of scale, an 800 MW plant might have a single large absorber and stripper (rather than three smaller ones) that would gain cost efficiencies.

Although the emissions from the auxiliary boiler could be routed through the post-combustion capture plant, the costs developed for this particular approach assumed venting these emissions. Venting lowered the overall CO_2 capture rate from 90% to 79%.

In contrast to the CATF Petra Nova-based approach, the retrofit costs described in IPM platform v6 are based on an integrating the post-combustion capture unit into the base coal plant such that the coal plant provides the steam and electricity needed for CO_2 capture. This form of retrofit was adopted by SaskPower for the Boundary Dam 3 project. The IPM platform v6 costs are based on a

NETL study that uses the same Cansolv technology that SaskPower adopted.[5] IPM platform 6 costs are based on AEO 2017 with adaptations to retrofits using NETL studies and a cost algorithm developed by Sargent and Lundy.[6] These costs are summarized in the table below:[7]

Table 6-2 Performance and Unit Cost Assumptions for Carbon Capture Retrofits on Coal Plants

Capacity (MW)	Heat Rate (Btu/kWh)	Capital Cost ($/kW)	Fixed O&M ($/kW-yr)	Variable O&M (mills/kWh)[2]	Capacity Penalty (%)	Heat Rate Penalty (%)
400	9,000	2,595	36.9	3.15	33.6	50.6
	10,000	2,960	41.2	3.71	37.3	59.5
	11,000	3,373	46.1	4.32	41.0	69.6
700	9,000	1,852	23.7	2.57	19.2	23.7
	10,000	2,071	26.1	2.93	21.3	27.0
	11,000	2,302	28.6	3.31	23.4	30.6
1,000	9,000	1,625	19.7	2.40	13.4	15.5
	10,000	1,810	21.6	2.71	14.9	17.5
	11,000	2,001	23.6	3.03	16.4	19.6

Note:
[1]Incremental costs are applied to the derated (after retrofit) MW size.
[2]The CO_2 Transportation, Storage, and Monitoring portion of the variable O&M has been removed from Sargent & Lundy cost method and modeled separately.

The capacity-derating penalty and associated heat rate penalty are an output of the Sargent & Lundy model (see section 5.1.1 for further details in regards to these penalties.

The IPM platform v6 costs have extremely high capacity penalties (33.6% to 41%) and high heat rate penalties (50.6% to 69.6%) for CO_2 capture applied to the 400 MW category. However, as the size of the unit grows to the 1000 MW category, these penalties shrink dramatically. The Capacity penalty falls to 13.4% - 16.4% and heat rate penalties fall to 15.5% to 19.6%.

In contrast, providing separate standalone steam generation for the capture unit as calculated by CATF eliminates the coal plant heat rate penalty (but at the cost of purchasing natural gas for the auxiliary boiler) and reduces the overall capacity penalty. But because the approach relies on modules for CCS capture units, no economies of scale are realized for 1000 MW or larger units.

Another key difference between the two approaches is impacts of natural gas prices. In a low-gas price environment, steam supplied to the capture unit by a natural gas-fired auxiliary boiler will be attractive. In a high gas price environment, it will be less so.

These factors suggest that all things being equal, that in their modeling results the IPM platform v6 cost assumptions will favor retrofits on larger plants (700 MW and 1000 MW) and be unfavorable to 400 MW unit retrofits. In contrast, the standalone steam source approach described by CATF will be more favorable to retrofitting units in the 400 MW size range relative to IPM platform v6 costs. However, IPM costs would be more attractive for 1000 MW retrofits than the CATF costs because the IPM approach achieves economies of scale.

[5] *Id.*
[6] *Id.* at 6-2 and 6-3.
[7] *Id.* at 6-3.

Together, these approaches complement one another. They address the full range of plant sizes and address needs for each category of sizes, providing greater confidence that CCS can be employed on coal plants of intermediate, large and very large sized units.

NGCC CCS Retrofits
CATF has developed CCS costs for NGCC CCS retrofits. The basis for these costs has been detailed in previous CATF filings with EPA, and they rely heavily on NETL baseline costs
The data for NGCC retrofits is described in the table below.

New NGCC Retrofits

Technology	**90% Capture Retrofit**
Heat rate (BTU/kWh)	7968
Incremental Capital cost ($2017 / kW)	$808
Incremental FOM ($2017/kw-yr)	$18.25
Incremental VOM ($2017/MWh)	$1.14

For new coal and gas plants, IPM platform v6 relies on costs developed in AEO 2017 as shown in the table below.[8] [9]

The documentation for the IPM model states that IPM includes a retrofit option NGCC plants, but the report does not include the NGCC with CCS retrofit data.[10] In EPA's initial run, NGCC with CCS is disabled.[11]

[8] The complete documentation for IPM platform v6 is found at https://www.epa.gov/airmarkets/documentation-epas-power-sector-modeling-platform-v6. The CCS costs are developed in Chapter 6 which is *available at*: https://www.epa.gov/airmarkets/documentation-epa-platform-v6-chapter-6-carbon-capture-transport-and-storage.
[9] New coal and gas plant prices are found on pages 6-1 and 6-2 of Chapter 6: Carbon Capture, Transport, and Storage available at: https://www.epa.gov/sites/production/files/2018-08/documents/epa_platform_v6_documentation_-_chapter_6_august_23_2018_updated_table_6-2_0.pdf.
[10] *Id.* at 6-1.
[11] *Id.* at 6-1, n. 50.