6. CO_2 Capture, Storage, and Transport

6.1 CO_2 Capture

The EPA 2023 Reference Case allows for the building of potential (new) Ultra-Supercritical Coal (USC) and Natural Gas Combined Cycle (NGCC) Electric Generating Units (EGUs) with Carbon Capture and Storage (CCS) technology.[56] CCS is also available as a retrofit option to existing coal-fired and NGCC EGUs.

6.1.1 CO_2 Capture for Potential EGUs

Potential USC EGUs are provided with two CCS options, namely, a 36-percent carbon dioxide (CO_2) capture efficiency option and a 90-percent CO_2 capture efficiency option. Potential NGCC EGUs, on the other hand, are provided with only the 90-percent CO_2 capture efficiency option. The CCS cost and performance assumptions provided in Table 6-1 are based on the Annual Energy Outlook 2023 (AEO 2023).

Table 6-1 Cost and Performance Assumptions for Potential USC and NGCC with and without Carbon Capture in the EPA 2023 Reference Case

	Combined Cycle - Single Shaft	Combined Cycle - Multi Shaft	Combined Cycle with 90% CCS	Ultra-supercritical Coal without CCS	Ultra-supercritical Coal with 36% CCS	Ultra-supercritical Coal with 90% CCS
Size (MW)	418	1083	377	650	650	650
First Year Available	2028	2028	2030	2028	2030	2030
Lead Time (Years)	3	3	3	4	4	4
Availability	87%	87%	87%	85%	85%	85%
Vintage #1 (2028)						
Heat Rate (Btu/kWh)	6,431	6,370		8,638		
Capital (2022$/kW)	1,118	989		3,789		
Fixed O&M (2022$/kW/yr)	15.87	13.73		45.68		
Variable O&M (2022$/MWh)	2.87	2.10		5.06		
Vintage #2 (2030)						
Heat Rate (Btu/kWh)	6,431	6,370	7,124	8,638	9,751	12,507
Capital (2022$/kW)	1,096	969	2,539	3,717	4,624	5,979
Fixed O&M (2022$/kW/yr)	15.87	13.73	31.06	45.68	61.11	67.02
Variable O&M (2022$/MWh)	2.87	2.10	6.57	5.06	7.97	12.35
Vintage #3 (2035)						
Heat Rate (Btu/kWh)	6,431	6,370	7,124	8,638	9,751	12,507
Capital (2022$/kW)	1,054	932	2,396	3,538	4,385	5,648
Fixed O&M (2022$/kW/yr)	15.87	13.73	31.06	45.68	61.11	67.02
Variable O&M (2022$/MWh)	2.87	2.10	6.57	5.06	7.97	12.35
Vintage #4 (2040)						
Heat Rate (Btu/kWh)	6,431	6,370	7,124	8,638	9,751	12,507
Capital (2022$/kW)	1,012	895	2,252	3,353	4,138	5,309
Fixed O&M (2022$/kW/yr)	15.87	13.73	31.06	45.68	61.11	67.02
Variable O&M (2022$/MWh)	2.87	2.10	6.57	5.06	7.97	12.35
Vintage #5 (2045)						
Heat Rate (Btu/kWh)	6,431	6,370	7,124	8,638	9,751	12,507
Capital (2022$/kW)	968	856	2,105	3,160	3,884	4,960
Fixed O&M (2022$/kW/yr)	15.87	13.73	31.06	45.68	61.11	67.02
Variable O&M (2022$/MWh)	2.87	2.10	6.57	5.06	7.97	12.35
Vintage #6 (2050-2055)						
Heat Rate (Btu/kWh)	6,431	6,370	7,124	8,638	9,751	12,507
Capital (2022$/kW)	922	816	1,958	2,966	3,628	4,612
Fixed O&M (2022$/kW/yr)	15.87	13.73	31.06	45.68	61.11	67.02
Variable O&M (2022$/MWh)	2.87	2.10	6.57	5.06	7.97	12.35

[56] The term carbon capture refers to removing CO_2 from the flue gases emitted by fossil fuel-fired EGUs.

6.1.2 CO_2 Capture for Existing EGUs with CCS Retrofit

As noted, EPA 2023 Reference Case offers the option of adding CCS to existing coal-fired and NGCC EGUs as a retrofit option starting in 2030. The option comes with a CO_2 capture efficiency of 90 percent. As in the case of potential EGUs with CCS, the CO_2 capture assumptions for CCS retrofit represent an amine-based, post-combustion CO_2 capture system.

The cost and performance assumptions provided in Table 6-2 are based on the Sargent & Lundy[57] cost algorithm (Attachment 6-1 summarizes the study)[58]. One issue that must be addressed when installing an amine-based, post-combustion CO_2 capture system is that sulfur oxides (e.g., sulfur dioxide (SO_2) and sulfur trioxide (SO_3)) in the EGU flue gas can degrade the amine-based solvent that absorbs the CO_2. Since the amine will preferentially absorb SO_2 before CO_2, it will be necessary to treat the EGU flue gas to lower the sulfur oxide concentration to 10 parts per million by volume or less. Meeting this constraint will require installing a supplemental Wet Flue Gas Desulfurization (FGD) technology or retrofitting an existing FGD. In EPA 2023 Reference Case, non FBC coal units without FGD or SCR controls are required to install FGD and SCR controls before retrofitting with CCS retrofits. However, existing FGDs are not retrofitted in the EPA 2023 Reference Case.

Table 6-2 Performance and Unit Cost (2022$) Assumptions for Carbon Capture in the EPA 2023 Reference Case

Technology	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 (%)
Coal Steam (Assuming Bituminous Coal)	400	9,000	2,160	31.47	4.87	27.61	38.14
		10,000	2,506	35.30	5.66	30.68	44.25
		11,000	2,884	39.49	6.51	33.75	50.94
	700	9,000	2,160	27.00	4.87	27.62	38.15
		10,000	2,506	30.63	5.66	30.69	44.27
		11,000	2,884	34.60	6.51	33.76	50.95
	1,000	9,000	2,160	25.21	4.87	27.62	38.16
		10,000	2,506	28.76	5.66	30.68	44.26
		11,000	2,884	32.64	6.51	33.75	50.94
Combined Cycle (Assuming Natural Gas)	100	7,000	1,176	47.13	1.90	15.23	17.97
		8,000	1,380	50.05	2.23	17.40	21.07
		9,000	1,594	53.13	2.58	19.58	24.35
	300	7,000	1,176	23.35	1.90	15.23	17.97
		8,000	1,380	25.64	2.23	17.40	21.07
		9,000	1,594	28.06	2.58	19.58	24.35
	500	7,000	1,177	18.59	1.90	15.24	17.99
		8,000	1,380	20.76	2.23	17.40	21.07
		9,000	1,595	23.05	2.58	19.60	24.37

[1]Incremental costs are applied to the derated (i.e., after retrofit) capacity.
[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.

[57] Sargent & Lundy. "*IPM Model – Updates to Cost and Performance for APC Technologies – CO_2 Reduction Retrofit Cost Development Methodology.*" Project 13527-002; March 2023.

[58] The capital cost of the CCS retrofit options on coal steam units is assumed to reduce by 5% starting in 2030 and by 10% starting in 2040. Similarly, the capital cost of the CCS retrofit options on combined cycle units is assumed to reduce by 5%, 7%,10%, and 15% starting in 2028, 2030, 2035, and 2040 respectively. These reductions are expected due to lessons learned and experience gained from demonstrations based on 45Q incentivized projects and movement toward competitive bidding projects with multiple executed projects for each supplier.

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.)

6.1.3 Coal-Fired Units Installing CCS Retrofit by 2030

Table 6-3 shows the existing coal-fired units allowed to install CCS retrofit by 2030 as these units are in the process of, or have completed Front-End Engineering Design (FEED) studies. All other coal steam and combined cycle units can install CCS retrofits starting in 2035.

Table 6-3 Existing Coal-Fired Units that can Install CCS Retrofit by 2030 in the EPA 2023 Reference Case

Unit Name	Plant Type	State Name
Four Corners	Coal Steam	New Mexico
Four Corners	Coal Steam	New Mexico
Gerald Gentleman	Coal Steam	Nebraska
Dry Fork Station	Coal Steam	Wyoming
Milton R Young	Coal Steam	North Dakota
Milton R Young	Coal Steam	North Dakota
Brame Energy Center	Coal Steam	Louisiana
Brame Energy Center	Coal Steam	Louisiana
Dallman	Coal Steam	Illinois
Prairie State Generating Station	Coal Steam	Illinois

6.2 CO_2 Storage

This section describes the cost of geologic storage of carbon dioxide as updated in 2023 using the GeoCAT 2.0 model and applied in the EPA 2023 Reference Case.[59] This update includes the quantity (in metric tons of capacity) and cost (in dollars per metric ton of CO_2) of potential geologic storage of carbon dioxide by location (generally defined as that portion of a geologic basin contained within one state) and by geologic storage type. There are three storage types that are estimated:

- Saline reservoirs (a.k.a. saline aquifers),
- Enhanced oil recovery, and
- Abandoned oil and gas fields.

The storage costs are calculated as the levelized[60] real-dollar costs for hypothetical storage projects of each type that might be developed inside of 10km by 10km grid "cells" located within each basin/state storage region. The portion of the gross cell area that can be developed is estimated based on:

- Population density (a higher population density reduces available area),
- Wilderness status, and
- A general availability factor that accounts for considerations such as geologic suitability, land accessibility, permitting difficulties, etc.

The geologic characteristics for each cell assumed for modeling come from several sources, including:

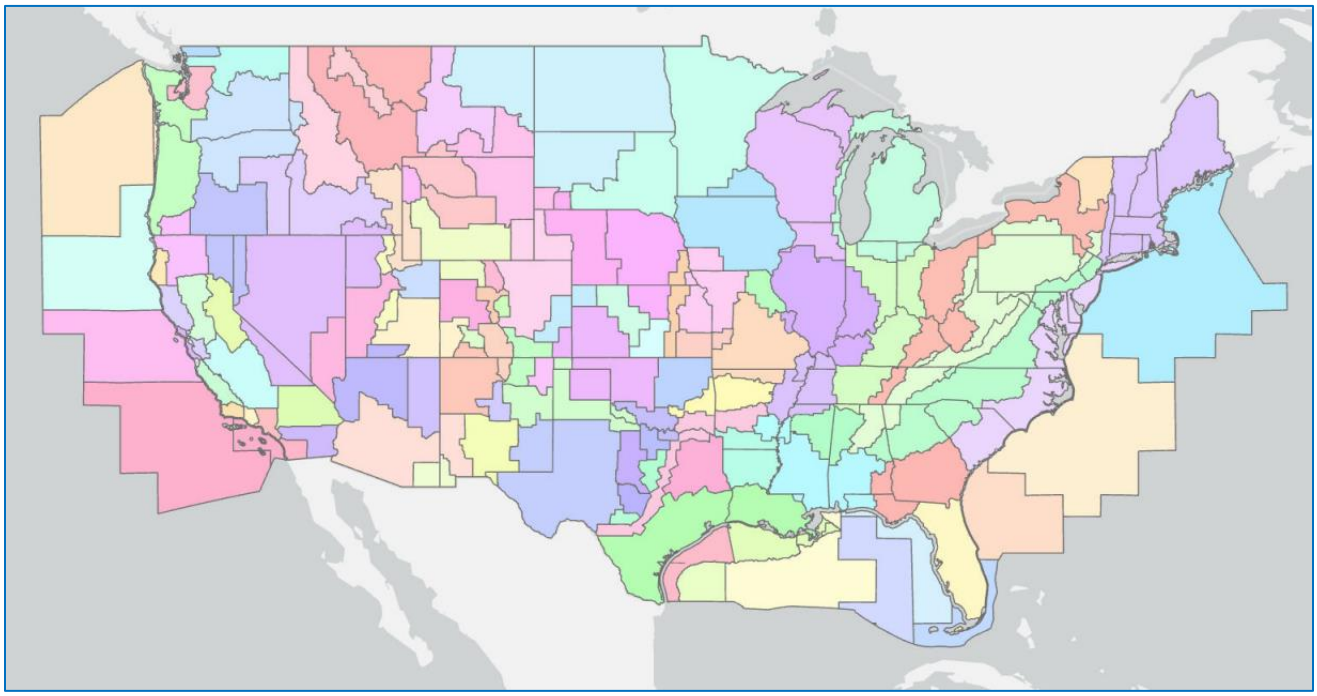
[59] A discussion of the original GeoCAT model and its application for EPA can be found in U.S. Environmental Protection Agency, Office of Water, "Geologic CO_2 Sequestration Technology and Cost Analysis, Technical Support Document" (EPA 816-B-08-009) June 2008, https://www.epa.gov/sites/production/files/2015-07/documents/support_uic_co2_technologyandcostanalysis.pdf and Harry Vidas, Robert Hugman and Christa Clapp, "Analysis of Geologic Sequestration Costs for the United States and Implications for Climate Change Mitigation," Science Digest, Energy Procedia, Volume 1, Issue 1, February 2009, Pages 4281-4288. Available online at https://www.sciencedirect.com/science/article/pii/S1876610209008832.

[60] The levelized real-dollar cost is the constant real $/unit revenue required by the provider of the geologic storage services to recover all capital and operating costs and exactly earn his target rate of return on his investment.

- Saline reservoir information from NATCARB[61] (saline reservoir depth, pressure, temperature, porosity, estimated potential storage capacity, etc.),
- Studies conducted by NETL to characterize the geology and estimate the economics of specific storage locations (saline reservoir depth, pressure, temperature, potential storage capacity, etc.),
- Studies conducted by the US Geologic Survey (regional temperature gradients, regional EOR potential, and storage capacity),
- Commercial oil and gas well databases (historical oil and gas well locations, reservoir depths, cumulative production, current reserves, regional formation tops, etc.).[62]

The outputs of the model are sequestration cost curves that indicate how much potential storage capacity is available at different CO_2 price points within each basin/state storage region. The various basins/states that were modeled as "storage regions" are shown in Figure 6-1. Note that not every storage type is available in each region and that regions with zero or near-zero capacity were not put into the EPA 2023 Reference Case when their estimated potential storage capacity was below three million metric tons (about the capacity needed for a 100 MW gas-fired power plant over 20 years).

Figure 6-1: Storage Regions in GeoCAT 2.0



Note: Regional boundaries are based on the American Association of Petroleum Geologists (AAPG) basin definitions, Department of Interior offshore leasing areas and state borders. Not every type of storage reservoir can be found in each storage region.

6.2.1 Unit Costs for Geologic Storage

The storage cost calculated for each type of storage for each cell is largely a function of the geologic characteristics of that cell and assumptions used in the costing algorithms for individual components of geologic sequestration of CO_2. The largest economic drivers are the costs of well operation, injection and monitoring well construction costs, and the costs of site monitoring. Depending on the nature of each cost

[61] NATCARB Saline spatial database, National Energy Technology Laboratory's Energy Data eXchange: NATCARB - Submissions - EDX (doe.gov)

[62] Historical oil and gas well data came from the Enverus Foundations databases: Enverus Foundations | Analyst-Curated Datasets | Enverus

element, “unit costs” are specified as dollars per storage site, dollars per square mile, dollars per foot as a function of well depth, dollars per labor hour, or other kinds of specifications or algorithms. The unit costs are then multiplied by the number of units required for a project. For example, the drilling of injection wells could be modelled as:

$230/foot injection well drilling and completion (D&C) construction cost
x 6,000 feet (measured drilling depth) per well
x 4 injection wells per project
= $5.52 million capital expenditures for injection well D&C per project.

6.2.2 Levelized Costs for Geologic Storage

The individual capital cost and operating cost components are combined into a pro forma project cash flow model for each 10km-by-10km cell. For example, the pro forma calculations for saline reservoirs would typically cover a four-year site characterization and construction period, a 30-year injection period, and a 50-year post-closure monitoring period. Each pro forma project has specifications for the volume of CO_2 injected, depth of injection, number of injection and monitoring wells, and other factors. Based on the timing of expenses and financial assumptions, these costs are translated in the model into levelized real dollars per metric ton of CO_2 injected using standard discounted cash flow techniques.[63] For EOR projects, the value of incremental crude oil recovery is subtracted from the gross storage costs to obtain the net costs – which can be negative in cases where the value of incremental oil exceeds the gross storage costs.

Note that the levelized cost shown here does not include the effect of federal tax credits under Section 45Q. Under the Inflation Reduction Act (IRA), the tax credit was raised to $60/metric ton for carbon dioxide used in enhanced oil recovery or other industrial operations and to $85/metric for permanently stored CO_2 such as in saline aquifers or abandoned oil and gas fields. The CCUS credit is available for CCUS projects beginning construction before January 1, 2033, and is to be applied to CO_2 quantities stored in the first 12 years of a project’s operation. While not included in the storage cost curves presented here, the value of any applicable tax credit is accounted for in the EPA 2023 Reference Case.

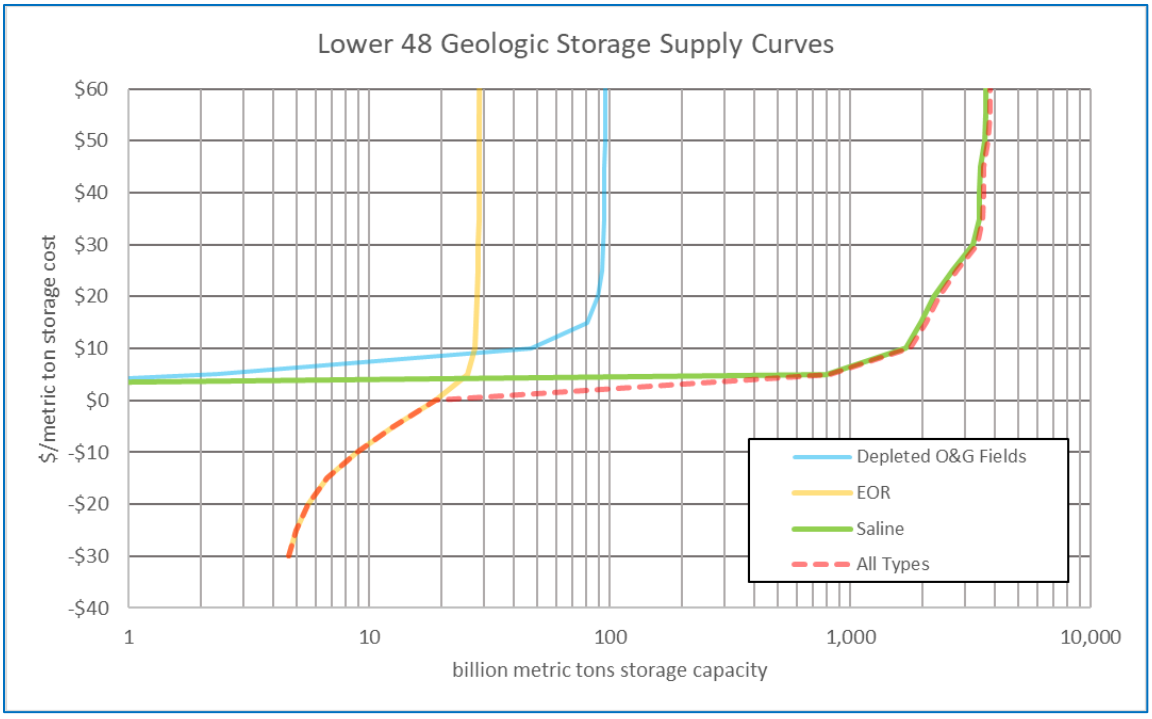
6.2.3 Aggregated Storage Cost Curves

For purposes of modeling within the EPA 2023 Reference Case, separate cost curves are created for each basin/state storage region in cost increments or steps of $5/metric ton. These curves are constructed by sorting each element (that is, the storage quantity and levelized cost for each individual cell/reservoir type) from lowest to highest costs and then aggregating all the elements into a single curve for each storage region.

For the Lower 48 as a whole, the geologic storage cost curves that result from this analysis are shown in Figure 6-2. Note that the x-axis is in units for billion metric tons of potential storage capacity and is shown on a logarithmic scale due to the wide range of capacities among the three storage types.

[63] In mathematical terms, the levelized cost produces a net present value of cash inflows (discounted at the operator’s weighted average cost of capital) that exactly equals the net present value of cash outflows (also discounted at the operator’s weighted average cost of capital).

Figure 6-2: Lower 48 Geologic Storage Supply Cost Curves



Note: These are levelized costs for geologic storage of carbon dioxide computed using GeoCAT 2.0. They do not include capture or transportation costs, and they also exclude the effects of 45Q tax credits.

The aggregated Lower 48 curves are constructed like the regional storage cost supply curves by sorting each element (that is, a reservoir type within each cell) starting from the least expensive to the most expensive and then accumulating the potential storage capacity at higher and higher costs. The aggregated Lower 48 curve for saline aquifers alone is shown as a green line, the curve for EOR alone is shown as an orange line, and the curve for abandoned oil and gas fields alone is shown as a blue line. The aggregation of all three types is shown as a dashed red line. The total modeled potential geologic storage capacity is 3,813 billion metric tons for the Lower 48. This is about 752 times the annual US carbon dioxide emission for all fossil fuel combustion (estimated in EPA's 2021 National GHG Inventory to be 5.067 billion metric tons).

6.3 CO_2 Transport

The EPA 2023 Reference Case includes the cost of transporting carbon dioxide by pipeline from a power plant to the geologic storage site. These pipeline transportation costs are represented by a matrix (in dollars per metric ton) between "sources" (that is, either center points of IPM regions for "new" power plants or individual existing power plant locations) and "sinks" (the center points of basin/state storage regions). These transport costs are a function of transport distance measured in miles and are based on the assumption that each source/sink pair is served by its own pipeline. The costs of pipeline transportation are based on standard engineering calculations for what diameter of pipeline is needed to transport a given volume of CO_2 and recent capital costs for pipelines in terms of dollars per inch-mile of pipeline. The tariff rate is calculated using standard discounted cash flow techniques given these capital costs plus some assumptions about the cost of capital (that is, interest on debt, return on equity, and the debt-to-equity ratio) and operating and maintenance costs for the CO_2 pipelines. The source-to-sink transportation cost matrix is created by multiplying the travel distances (calculated with geospatial geometry using latitude-longitude center points of the regions) by the relevant dollar-per-ton-mile transportation cost factors. To limit the size of the cost matrix, only the transportation links with a distance of less than 750 miles are modeled in the EPA 2023 Reference Case.

List of tables that are uploaded directly to the web:

Table 6-4 CO_2 Storage Cost Curves in EPA 2023 Reference Case

Table 6-5 CO_2 Transportation Matrix in EPA 2023 Reference Case

Attachment 6-1 CO_2 Reduction Retrofit Cost Development Methodology