6. CO_2 Capture, Transport, and Storage

6.1 CO_2 Capture

Among the potential (new) units that the model can build in EPA Base Case v.5.13 are advanced coal-fired units with CO_2 capture (carbon capture).[37] The cost and performance characteristics of these units are shown in Table 4-13 and are discussed in Chapter 4.

In addition to offering carbon capture capabilities on potential units that the model builds as new capacity, EPA Base Case v.5.13 provides carbon capture as a retrofit option for existing pulverized coal plants. The incremental costs and performance assumptions for these retrofits are shown in Table 6-1.

Table 6-1 Performance and Unit Cost Assumptions for Carbon Capture Retrofits on Pulverized Coal Plants

Applicability (Original MW Size)	**> 400 MW**
Incremental[a] Capital Cost (2011 $/kW)	1,794
Incremental[a] FOM (2011 $/kW-yr)	27.2
Incremental[a] VOM (2011 (mills/kWh)	3.2
Capacity Penalty (%)	-25%
Heat Rate Penalty (%)	33%
CO_2 Removal (%)	90%

Note:
[a] Incremental costs are applied to the derated (after retrofit) MW size.

The capital costs shown in Table 6-1 are based on the costs reported for Case 1 in a study performed for the U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL) by a team consisting of Alstom Power, Inc., American Electric Power (AEP), ABB Global, and the Ohio Coal Development Office.[38] For Case 1 this comprehensive engineering study, conducted from 1999-2001, evaluated the impacts on plant performance and the required cost to add facilities to capture greater than 90% of the CO_2 emitted by AEP's Conesville Ohio Unit #5. This is a 450 MW subcriticalpulverized bituminous coal plant with a lime based FGD, and an electrostatic precipitator for particulate control.[39] The carbon capture method that was evaluated was an amine-based scrubber using the Kerr-McGee/ABB Lummus Global commercially available monoethanolamine (MEA) process. In this system the flue gas leaves the FGD (which has been modified to reduce the SO_2 concentration as required by the MEA process) and is cooled and ducted to the MEA system where more than 96% of the CO_2 can be removed. For use in EPA Base Case v.5.13 the capital cost was converted to constant 2011$ from the 2006$ costs reported in the NETL study.

A capacity derating penalty of 25% was assumed, based on reported research and field experience as of 2010. The corresponding heat rate penalty was 33%. (For an explanation of the capacity and heat rate penalties and how they are calculated, see the discussion under VOM in section 5.1.1.)

[37] The term "New Advanced Coal with CCS" encompasses various technologies that can provide carbon capture. These include supercritical steam generators with carbon capture and integrated gasification combined cycle (IGCC) with carbon capture. For purposes of characterizing the cost and performance characteristics of advanced coal with carbon capture, supercritical steam generators with carbon capture was used in Table 4-13.

[38] Carbon Dioxide Capture from Existing Coal-Fired Power Plants" DOE/NETL-401/110907. Final Report (Original Issue Date, December 2006) Revision Date, November 2007 (http://www.netl.doe.gov/energy-analyses/pubs/CO2%20Retrofit%20From%20Existing%20Plants%20Revised%20November%202007.pdf. A summary of costs for each of the cases appears in Table 3-65 (p. 139).

[39] Subcritical" refers to thermal power plants that operate below the "critical temperature" and "critical pressure" (220 bar) where boiling (i.e., the formation of steam bubbles in water) no longer occurs. Such units are less efficient than "supercritical" and "ultra supercritical" steam generators.

Since the fixed (FOM) and variable operating and maintenance (VOM) costs from the Conesville study were given without documentation, EPA relied on a NETL study that fully documented these costs coupled with the expert judgment of EPA's engineering staff to obtain the FOM and VOM values shown in Table 6-1.[40]

6.2 CO_2 Storage

The capacity and cost assumptions for CO_2 storage in EPA Base Case v.5.13 are based on GeoCAT (Geosequestration Cost Analysis Tool), a spreadsheet model developed for EPA by ICF in support of EPA's draft Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide Geologic Storage Wells.[41] The GeoCAT model combines detailed characteristics of sequestration capacity by state and geologic setting for the U.S. with costing algorithms for individual components of geologic sequestration of CO_2. The outputs of the model are regional sequestration cost curves that indicate how much potential storage capacity is available at different CO_2 storage cost points.

The GeoCAT model includes three modules: a unit cost specification module, a project scenario costing module, and a geologic and regional cost curve module. The unit cost module includes data and assumptions for 120 unit cost elements falling within the following cost categories:

- Geologic site characterization
- Monitoring the movement of CO_2 in the subsurface
- Injection well construction
- Area of review and corrective action (including fluid flow and reservoir modeling during and after injection and identification, evaluation, and remediation of existing wells within the area of review)
- Well operation
- Mechanical integrity testing
- Financial responsibility (to maintain sufficient resources for activities related to closing and remediation of the site)
- General and administrative

Of the ten cost categories for geologic CO_2 sequestration listed above, the largest cost drivers (in roughly descending order of magnitude) are well operation, injection well construction, and monitoring.

The costs derived in the unit cost specification module are used in the GeoCAT project scenario costing module to develop commercial scale costs for seven sequestration scenarios of geologic settings:

- Saline reservoirs
- Depleted gas fields
- Depleted oil fields
- Enhanced oil recovery
- Enhanced coal bed methane recovery

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[40] Cost and Performance Baseline for Fossil Energy Plants" DOE/NETL-2007/1281, Volume 1: Bituminous Coal and Natural Gas to Electricity, Final Report (Original Issue Date, May 2007) Revision 1, August 2007 (http://www.netl.doe.gov/energy-analyses/pubs/Bituminous%20Baseline_Final%20Report.pdf). The VOM and FOM cost calculations for Case 9 appear in Exhibits 4-14 (p. 349) and for Case 10 in Exhibit 4-24 (p. 373).

[41] Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells," *Federal Register*, July 25, 2008 (Volume 73, Number 144), pp. 43491-43541. www.epa.gov/fedrgstr/EPA-WATER/2008/July/Day-25/w16626.htm and www.epa.gov/safewater/uic/wells_sequestration.html#regdevelopment.

- Enhanced shale gas
- Basalt storage

EPA's application of GeoCAT includes only storage capacity for the first four scenarios. The last three reservoir types are not included because they are considered technically uncertain and minor for the foreseeable future.

The results of the project scenario costing module are taken as inputs into the geologic and regional cost curve module of GeoCAT which generates national and regional "cost curves" indicating the volume of sequestration capacity in each region and state in the U.S. as a function of cost. This module contains a database of sequestration capacity by state and geologic reservoir type. It incorporates assessments from the U.S. Department of Energy's "Carbon Sequestration Atlas of the United States and Canada," enhanced by ICF to include assessments of the Gulf of Mexico, shale gas sequestration potential, and the use of distribution of proved oil and gas recovery by region to estimate CO_2 potential in areas not covered in the DOE atlas.[42] The geologic and regional cost curve module also has a characterization of regionalized costs, drilling depths, and other factors that go into the regional cost curves.[43]

For EPA Base Case v.5.13, GeoCAT identified storage opportunities in 33 of the lower 48 continental states and storage cost curves were developed for each of them.[44] The storage curve for California is designated as California offshore. Louisiana and Texas have both onshore and offshore storage cost curves. In addition, there are Atlantic offshore and Pacific offshore storage cost curves. The result is a total of 37 storage cost curves which are shown in Excerpt from Table 6-2.[45]

The cost curves shown in Excerpt from Table 6-2 are in the form of step functions. This implies that in any given year a specified amount of storage is available at a particular step price until either the annual storage limit (column 4) or the total storage capacity (column 5) is reached. In determining whether the total storage capacity has been reached, the model tracks the cumulative storage used up through the current year. Once the cumulative storage used equals the total storage capacity, no more storage is available going forward at the particular step price.

CO_2 storage opportunities are relevant not just to power sector sources, but also to sources in other industrial sectors. Therefore, before being incorporated as a supply representation into EPA Base Case v.5.13, the original CO_2 storage capacity in each storage region was reduced by an estimate of the storage that would be occupied by CO_2 generated by other industrial sector sources at the relevant level of cost effectiveness (represented by \$/ton CO_2 storage cost). To do this, ICF first estimated the level of industrial demand for CO_2 storage in each CO_2 storage region in a scenario where the value of abating CO_2 emissions is assumed to be \$150 per ton (this abatement value is relevant not only to willingness to

[42] Carbon Sequestration Atlas of the United States and Canada", U.S. Department of Energy, National Energy Technology Laboratory, Morgantown, WV, March, 2007.

[43] Detailed discussions of the 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, http://www.epa.gov/ogwdw000/uic/pdfs/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 www.sciencedirect.com.

[44] The states without identified storage opportunities in EPA Base Case v.5.13 are Connecticut, Delaware, Idaho, Iowa, Maine, Maryland, Massachusetts, Minnesota, Missouri, New Hampshire, New Jersey, North Carolina, Rhode Island, Vermont, and Wisconsin. This implies that these states did not present storage opportunities for the four sequestration scenarios included in EPA's inventory, i.e., saline reservoirs, depleted gas fields, depleted oil fields, and enhanced oil recovery.

[45] For consistency across the emission costs represented in v.5.13, the costs shown in Tables 9-23 and 9-24 are expressed in units of dollars per short ton. In IPM documentation and outputs the convention is to use the word "tons" to indicate short tons and the word "tonnes" to indicate metric tons. In discussing CO_2 outside of the modeling framework, the international convention is to use metric tons. To obtain the \$/tonne equivalent multiply the \$/ton values shown In Tables 9-34 and 9-24 by 1.1023.

pay for storage but also for the cost of capture and transportation of the abated CO_2).[46] Then, for each region ICF calculated the ratio of the industrial demand to total storage capacity available for a storage price of less than $10/ton. (An upper limit of $10/ton was chosen because the considerable amount of storage available up to that price could be expected to exhaust the industrial demand.) Converting this to a percent value and subtracting from 100%, ICF obtained the percent of storage capacity available to the electricity sector at less than $10/ton. Finally, the "Annual Step Bound (MMTons)" and "Total Storage Capacity (MMTons)" was multiplied by this percentage value for each step below $10/ton[47] in the cost curves for the region to obtain the reduced storage capacity that went into the storage cost curves for the electric sector in EPA Base Case v.5.13. Thus, the values shown in Excerpt from Table 6-2 represent the storage available specifically to the electric sector.

The price steps in the Excerpt from Table 6-2 are the same from region to region. (That is, STEP5 [column 2] has a step cost value of $4.84/Ton [column 3] across all storage regions [column 1]. This across-region price equivalency holds for every step.) However, the amount of storage available in any given year (labeled "Annual Step Bound (MMTons)" in column 4) and the total storage available over all years (labeled "Total Storage Capacity (MMTons)" in column 5) vary from region to region. In any given region, the cost curves are the same for every run year. This feature implies that over the modeling time horizon no new storage will be added to augment the current storage inventory. This assumption is not meant to imply that additional storage is unavailable and may be revisited if model runs exhaust key components in the storage inventory.

Excerpt from Table 6-2 CO_2 Storage Cost Curves in EPA Base Case v.5.13

This is a small excerpt of the data in Excerpt from Table 6-2. The complete data set in spreadsheet format can be downloaded via the link found at http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html.

CO_2 Storage Region	Step Name	CO_2 Storage Step Cost (2011$/Ton)	Annual Step Bound (MMTons)	Total Storage Capacity (MMTons)
Alabama	STEP1	-14.52	1	45
	STEP2	-9.68	0	0
	STEP3	-4.84	0	0
	STEP4	0.00	0	6
	STEP5	4.84	31	1,568
	STEP6	9.68	39	1,967
	STEP7	14.52	38	1,895
	STEP8	19.36	0	9
	STEP9	24.20	4	186
	STEP10	29.04	13	639
	STEP11	33.88	0	7
	STEP12	38.72	0	14
	STEP13	43.56	0	0
	STEP14	48.41	1	68
	STEP15	53.25	0	0
	STEP16	58.09	0	14
	STEP17	62.93	0	0

[46] The approach that ICF employed to estimate industrial demand for CO_2 storage is described in ICF International, "Methodology and Results for Initial Forecast of Industrial CCS Volumes," January 2009.

[47] Zero and negative cost steps represent storage available from enhanced oil recovery (EOR) where oil producers either pay or offer free storage for CO_2 that is injected into mature oil wells to enhance the amount of oil recovered. There is also a market for CO_2 injection in enhanced coal bed methane (ECBM) production. ECBM is excluded from EPA's inventory as discussed earlier.

CO_2 Storage Region	Step Name	CO_2 Storage Step Cost (2011$/Ton)	Annual Step Bound (MMTons)	Total Storage Capacity (MMTons)
	STEP18	67.77	0	0
	STEP19	72.61	0	0
Arizona	STEP1	-14.52	0	0
	STEP2	-9.68	0	0
	STEP3	-4.84	0	0
	STEP4	0.00	0	0
	STEP5	4.84	121	6,026
	STEP6	9.68	145	7,275
	STEP7	14.52	113	5,659
	STEP8	19.36	0	0
	STEP9	24.20	38	1,887
	STEP10	29.04	0	1
	STEP11	33.88	0	0
	STEP12	38.72	0	0
	STEP13	43.56	0	0
	STEP14	48.41	0	0
	STEP15	53.25	0	0
	STEP16	58.09	0	0
	STEP17	62.93	0	0
	STEP18	67.77	0	0
	STEP19	72.61	0	0

Note: The curves for each region are applicable in each model run year 2016 - 2050.

6.3 CO_2 Transport

Each of the 64 IPM model regions can send CO_2 to the 37 regions represented by the storage cost curves in Excerpt from Table 6-2. The associated transport costs (in 2011$/Ton) are shown in Excerpt from Table 6-3.

These costs were derived by first calculating the pipeline distance from each of the CO_2 Production Regions to each of the CO_2 Storage Regions listed in Excerpt from Table 6-3. Since there are large economies of scale for pipelines, CO_2 transportation costs depend on how many power plants and industrial CO_2 sources could share a pipeline over a given distance. Consequently, the method assumes that the longer the distance from the source of the CO_2 to the sink for the CO_2 the greater the chance for other sources to share in the transportation costs, including pipeline costs (in $/inch-mile) and cost of service (in $/ton per 75 miles). These cost components are functions of the required diameter and thickness of the pipeline and the flow capacity of the pipeline, which themselves are functions of the assumed number of power plants using the pipeline.

Excerpt from Table 6-3 CO_2 Transportation Matrix in EPA Base Case v.5.13

This is a small excerpt of the data in Table 6-3. The complete data set in spreadsheet format can be downloaded via the link found at http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html.

CO_2 Production Region	CO_2 Storage Region	Cost (2011$/Ton)
ERC_REST	Alabama	13.20
	Arizona	18.75
	Arkansas	8.27
	Atlantic Offshore	24.44
	California	30.21
	Colorado	17.79
	Florida	20.86
	Georgia	19.97
	Illinois	17.01
	Indiana	18.43
	Kansas	12.54
	Kentucky	20.25
	Louisiana	8.48
	Louisiana Offshore	8.61
	Michigan	23.76
	Mississippi	9.94
	Montana	26.83
	Nebraska	17.88
	Nevada	25.95
	New Mexico	16.77
	New York	28.40
	North Dakota	26.53
	Ohio	23.70
	Oklahoma	9.35
	Oregon	37.00
	Pacific Offshore	27.83
	Pennsylvania	26.33
	South Carolina	20.72
	South Dakota	23.53
	Tennessee	17.12
	Texas	4.48
	Texas Offshore	6.64
	Utah	21.96
	Virginia	23.60
	Washington	967.14
	West Virginia	22.32
	Wyoming	22.76

Notes:
Production Regions are equal to IPM model regions