

6. CO₂ Capture, Storage, and Transport

6.1 CO₂ Capture

The EPA Platform v6 using IPM can build Ultra-Supercritical (USC) coal and Natural Gas Combined Cycle (NGCC) Electric Generating Units (EGUs) with Carbon Capture⁴⁹ and Storage (CCS) technology. In addition, IPM includes a retrofit option to add CCS technology to existing coal steam and NGCC EGUs.

6.1.1 CO₂ Capture for Potential EGUs

Carbon capture for potential USC EGUs is represented as two model plant options with different CO₂ capture efficiencies of 30 percent and 90 percent. EPA Platform v6 can offer CCS with a CO₂ capture efficiency of 90 percent for new NGCC units.⁵⁰ The USC with CCS and NGCC with CCS model plant options are configured assuming construction at greenfield sites. The cost and performance data provided in Table 6-1 is based on the Annual Energy Outlook 2017 (AEO 2017). The basis for these costs are studies prepared for the U.S. Department of Energy's (DoE's) Energy Information Administration (EIA).^{51,52}

The USC costs were developed for a generic 650-megawatt (MW) net output USC EGU with a nominal heat rate of 8,609 British Thermal Units (Btus) per kilowatt-hour (kW-hr) in 2021. The USC EGU uses a "one-on-one" configuration. That is, the EGU is comprised of one pulverized coal (PC) steam generator and one steam turbine (ST). The steam generator is fired with Illinois No. 6 (Herrin seam, Old Ben Mine) bituminous coal and operates at steam conditions of 3,800 pounds per square inch-absolute (psia) and 1,112 degrees Fahrenheit (°F). USC with a CCS is equipped with an amine-based, post-combustion CO₂ capture system. Mercury (Hg), sulfur oxides (SO_x), nitrogen oxides (NO_x), and particulate matter (PM) emissions from the USC EGU are controlled with state-of-the-art air pollution control equipment including Dry Sorbent Injection (DSI), Activated Carbon Injection (ACI), Wet Flue Gas Desulfurization (WFGD) scrubber; low NO_x burners (LNBs), Selective Catalytic Reduction (SCR), and a fabric filter baghouse.

⁴⁹ The term "carbon capture" refers primarily to removing carbon dioxide (CO₂) from the flue gases emitted by fossil fuel-fired EGUs.

⁵⁰ Note that the NGCC with CCS option is disabled in the EPA Platform v6 November 2018 Reference Case.

⁵¹ Energy Information Administration (EIA). "Capital Cost Estimates for Utility Scale Electricity Generating Plants" (November 2016). "Cost and Performance Characteristics of New Generating Technologies, Annual Energy Outlook 2017" (January 2017). "Addendum: Capital Cost Estimates for Utility Scale Electricity Generating Plants" (April 2017).

⁵² Note that the science of thermodynamics only refers to subcritical and supercritical states. "Ultra-Supercritical" is an industry term that refers to operating at higher temperatures and/or pressures within the supercritical regime. Distinct liquid and gas phases do not exist in a substance at a temperature and pressure above its critical point.

Table 6-1 Cost and Performance Assumptions for Potential USC and NGCC with and without Carbon Capture⁵³

	Advanced Combined Cycle	Advanced Combined Cycle with CCS	Ultrasupercritical Coal with 30% CCS	Ultrasupercritical Coal with 90% CCS	Ultrasupercritical Coal without CCS
Vintage #1 (2021)					
Heat Rate (Btu/kWh)	6,267	7,514	9,644	11,171	8,609
Capital (2016\$/kW)	1,081	2,104	4,953	5,477	3,580
Fixed O&M (2016\$/kW/yr)	9.9	33.2	69.6	80.8	42.1
Variable O&M (2016\$/MWh)	2	7.1	7.1	9.5	4.6
Vintage #2 (2023)					
Heat Rate (Btu/kWh)	6,233	7,504	9,433	10,214	8,514
Capital (2016\$/kW)	1,064	2,059	4,863	5,378	3,516
Fixed O&M (2016\$/kW/yr)	9.9	33.2	69.6	80.8	42.1
Variable O&M (2016\$/MWh)	2	7.1	7.1	9.5	4.6
Vintage #3 (2025-2054)					
Heat Rate (Btu/kWh)	6,200	7,493	9,221	9,257	8,323
Capital (2016\$/kW)	1,041	2,003	4,746	5,249	3,431
Fixed O&M (2016\$/kW/yr)	9.9	33.2	69.6	80.8	42.1
Variable O&M (2016\$/MWh)	2	7.1	7.1	9.5	4.6

The NGCC costs were developed for a generic 702-MW net output NGCC EGU with a nominal heat rate of 6,267 Btus per kW-hr in 2021. The USC EGU uses a “two-on-two-on-one” configuration. That is, the combined cycle technology EGU is comprised of two natural gas-fired F5-class combustion turbines (CTs), two supplementary Heat Recovery Steam Generators (HRSGs), and one ST. The NGCC facility is fueled with pipeline-quality natural gas with a higher heating value (HHV) of 1,040 Btus per standard cubic foot (scf). Steam is produced at 3,800 psia and 1,112 oF. The two HRSGs extract heat from the two CTs to power the one ST. NGCC with a CCS is equipped with an amine-based, post-combustion CO₂ capture system. NO_x emissions from the NGCC EGU are controlled with LNBs and a SCR system.

6.1.2 CO₂ Capture via Retrofitting Existing EGUs

EPA Platform v6 offers the option of retrofitting CCS to existing coal-fired power plants and NGCCs at a CO₂ capture efficiency of 90 percent.⁵⁴ The CO₂ capture process is modeled assuming the use of an amine-based, post-combustion CO₂ capture system.

The cost and performance data provided in Table 6-2 is based on the Sargent & Lundy⁵⁵ cost algorithm (Attachment 6-1 summarizes this study) and a DoE/National Environmental Technology Laboratory (NETL)

⁵³ The cost and performance characteristics for these new units are also shown in Table 4-13 and discussed further in Chapter 4.

⁵⁴ Note that the NGCC with CCS option is disabled in the EPA Platform v6 November 2018 Reference Case.

⁵⁵ Sargent & Lundy. “IPM Model – Updates to Cost and Performance for APC Technologies – CO₂ Reduction Cost Development Methodology.” Project 13527-001; February 2017.

study.⁵⁶ As part of developing documentation for EPA Platform v6, the capital costs were converted to 2016 dollars from the 2011 dollar basis used in the referenced DoE/NETL study. Note that one of the carbon capture information resources is the Shell Cansolv[®] technology, which was installed on Unit 3⁵⁷ at SaskPower's Boundary Dam Power Station near Estevan, Saskatchewan, Canada in October 2014.⁵⁸ One issue that must be addressed when installing an amine-based, post-combustion CO₂ capture system is that sulfur oxides (e.g., SO₂ and sulfur trioxide (SO₃)) in the EGU flue gas can degrade the amine-based solvent used to absorb the CO₂ from the EGU flue gas. Since the amine will preferentially absorb SO₂ before CO₂, it will be necessary to treat the EGU flue gas to lower the sulfur oxide concentration to 10 parts per million by volume (ppmv) or less. Meeting this constraint will require installing supplemental WFGD technology (e.g., the SO₂ "polishing" scrubber referenced in footnote 58), or retrofitting existing FGD.

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:

¹Incremental costs are applied to the derated (after retrofit) MW size.

²The CO₂ 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.)

6.2 CO₂ Storage

The capacity and cost assumptions for CO₂ storage in EPA Platform v6 are based on the Geosequestration Cost Analysis Tool (GeoCAT); a spreadsheet model developed for the U.S. EPA by ICF, Inc. (ICF) in support of the U.S. EPA's Underground Injection Control (UIC) Program for CO₂ Geologic Storage Wells.⁵⁹ For EPA Platform v6, ICF updated the major cost components in the GeoCAT model, including revising onshore and offshore injection and monitoring costs to reflect 2016 industry drilling

⁵⁶ DoE/NETL. "Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity. Revision 3." DoE/NETL-2015/1723. July 6, 2015. (See https://www.netl.doe.gov/projects/files/CostandPerformanceBaselineforFossilEnergyPlantsVolume1aBitCoalPCandNaturalGasToElectRev3_070615.pdf)

⁵⁷ At the time of project execution, Sask Power's Boundary Dam Unit 3 was a 43-year old lignite-fired 139 MW net generating unit. Upon completion, Boundary Dam Unit 3 became the first utility-scale power plant retrofitted with CCS technology. Sask Power estimates that the \$1.2 billion project extended Unit 3's life by 30 years. Note that the associated energy penalty for installing the CCS technology derated Unit 3 from 139 to 110 MWs.

⁵⁸ The Shell Cansolv[®] carbon capture system at Boundary Dam Unit 3 uses a proprietary amine solvent to absorb SO₂ and CO₂ from the EGU flue gases. The carbon capture process requires very low SO₂ levels in the flue gases prior to CO₂ capture because, if present, the amine would preferentially absorb SO₂ before CO₂. The Shell Cansolv[®] SO₂ capture process was installed upstream of the CO₂ scrubber to "polish" the feed to the CO₂ scrubber.

⁵⁹ Federal Requirements Under the UIC Program for CO₂ Geologic Sequestration Wells, Federal Register, December 10, 2010 (Volume 75, Number 237), pages 77229-77303.

costs.⁶⁰ All cost components in the model were also converted to a 2016 dollar basis. In addition to updating costs in the model, ICF updated storage capacity, well injectivity, and other assumptions by state and offshore area primarily using data from the research program conducted at DoE/NETL. Assumptions for the amount of carbon dioxide injected for EOR was updated using the past several years of performance data.

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 CO₂ geologic sequestration. The model outputs are regional sequestration cost curves that indicate how much potential storage capacity is available at different CO₂ storage cost points.

The GeoCAT model includes three modules:

1. A unit cost specification module,
2. A project scenario costing module, and
3. A geologic and regional cost curve module.

The unit cost specification module includes data and assumptions for 120 cost elements falling within the following categories:

1. Geologic site characterization
2. 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)
3. Injection well and other facilities construction
4. Well operation
5. Monitoring the movement of CO₂ in the subsurface
6. Mechanical integrity testing
7. Financial responsibility (to maintain sufficient resources for activities related to closing and remediation of the site)
8. Post injection site care
9. Site closure
10. General and administrative

Of the ten cost categories for geologic CO₂ sequestration listed above, the largest cost drivers (in roughly descending order of magnitude) are well operation, injection well and other facilities construction, and monitoring the movement of CO₂ in the subsurface. The cost estimates are consistent with the requirements for geologic storage facilities under the UIC Class VI rule⁶¹ and Greenhouse Gas (GhG) Reporting Program Subpart RR⁶². The price of oil assumed for the calculation of EOR economics is \$75/barrel.

⁶⁰ The major data sources for updating costs was the Bureau of Labor Statistics (BLS) Producers Price Index (PPI) for various products and services related to oil and gas well drilling (<https://www.bls.gov/ppi/>), the “Joint Association Survey of Drilling Costs” published by the American Petroleum Institute (http://www.api.org/products-and-services/statistics#tab_overview), and the “Well Cost Study” published by the Petroleum Services Association of Canada (<https://www.pfac.ca/resources/well-cost-study-overview/>).

⁶¹ *Supra* Note 59.

⁶² Title 40 of the Code of Federal Regulations (CFR), Part 98 (Mandatory GhG Reporting), Subpart RR (Geologic Sequestration of CO₂). See <https://ecfr.io/Title-40/sp40.23.98.rr>.

The costs derived in the unit cost specification module are used in the GeoCAT project scenario costing module to develop commercial scale costs for eight sequestration scenarios compliant with UIC Class VI standards and GhG Reporting Program Subpart RR:

1. Deep saline formations
2. Depleted gas fields
3. Depleted oil fields
4. Enhanced oil recovery
5. Enhanced coal bed methane recovery
6. Enhanced shale gas
7. Basalt storage
8. Unmineable coal seams

EPA's GeoCAT application for CO₂ sequestration includes only storage capacity for the first four sequestration scenarios. The last four reservoir types are not included because they are not considered technically mature enough to allow CO₂ storage in the foreseeable future.

The current GeoCAT model includes the most recent DoE analysis of the lower-48 states CO₂ sequestration capacities from the "Carbon Sequestration Atlas of the United States and Canada Version 5."⁶³ ICF enhanced these assessments to include additional details needed for economic modeling such as the distribution of capacity by state, drilling depth, injectivity, etc. The geologic and regional cost curve module applies regionalized unit cost factors to these geologic characterizations to develop regional geologic storage cost curves.⁶⁴ The analysis of storage volumes is carried out by regional carbon sequestration partnerships as overseen by NETL in Morgantown, West Virginia. State level onshore and offshore capacity volumes are reported for storage in oil and gas reservoirs and deep saline formations. The great majority of storage volume is in deep saline formations, which are present in many states and in most states with oil and gas production. In the most recent version of the Atlas, offshore storage volumes have also been broken out by DoE into the Gulf of Mexico, Atlantic, and Pacific Outer Continental Shelf (OCS) regions. ICF carried out a separate analysis to break out CO₂ EOR storage potential from the total potential in oil and gas reservoirs reported in NATCARB.

Efficiency Assumptions for EOR Uses of CO₂

Relying on recent performance data, the geologic storage cost curve for EOR is based on an average EOR efficiency of 10 thousand cubic feet (Mcf) of CO₂ per incremental barrel of crude oil. The NETL "CO₂ EOR Primer"⁶⁵ shows that from the start of CO₂ floods in 1972 to 2008 the average efficiency was 7.66 Mcf per bbl. Data for the most recent seven year has shown a lower average efficiency of over 10.32 Mcf/bbl. This creates an average of 8.62 Mcf/bbl for all years from 1972 to 2016.

⁶³ Carbon Sequestration Atlas of the United States and Canada – Version 5 (2015), U.S. Department of Energy, National Energy Technology Laboratory, Morgantown, WV <https://www.netl.doe.gov/research/coal/carbon-storage/atlasv>. Accessed mid-October 2016 with data updates through 2015.

⁶⁴ Detailed discussions of the GeoCAT model and its application for EPA can be found in U.S. Environmental Protection Agency, Office of Water, "Geologic CO₂ 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>.

⁶⁵ National Energy Technology Laboratory, "Carbon Dioxide Enhanced Oil Recovery", 2010, https://www.netl.doe.gov/file%20library/research/oil-gas/CO2_EOR_Primer.pdf

Historical CO₂ EOR: 1972-2008	
Billion cubic feet of CO ₂	11,000
Million barrels of crude oil	1,437
Mcf/barrel	7.66
<i>Source: NETL, "Carbon Dioxide Enhanced Oil Recovery", 2010</i>	
Historical CO₂ EOR: 2009-2016	
Billion cubic feet of CO ₂	8,339
Million barrels of crude oil	808
Mcf/barrel	10.32
<i>Source: ICF estimates based on EPA GHG Inventory and Oil & Gas Journal Annual EOR Survey</i>	
Historical CO₂ EOR: 1972-2016	
Billion cubic feet of CO ₂	19,339
Million barrels of crude oil	2,244
Mcf/barrel	8.62
<i>Source: Sum of prior two tables</i>	

The average of all historical and ongoing EOR projects through the end of their lifetimes is likely to exceed 9.0 Mcf/bbl as they continue to operate at ratios above 10 Mcf/bbl.⁶⁶ ICF has chosen a calibration point of 10 Mcf/bbl for the average of potential future CO₂ EOR under the belief that the quality of future projects would likely be worse (i.e., require more CO₂ per unit of incremental oil production) than historical projects. The historical projects were presumably chosen, in part, because of their favorable characteristics, as well as their proximity to sources of CO₂. Future projects are likely to have poorer characteristics and would be expected to require more CO₂. Also, because of the economic incentive to get the 45Q tax credits, it is possible that project designs might change to use more CO₂, particularly in the years the credit is available. The revised average efficiency value of 10 Mcf/bbl is approximately 15 percent higher than the original version of GeoCAT, which was calibrated to the older historical data.

There is considerable variation in CO₂ requirements among projects initiated in the US. The most efficient projects use less than 3 Mcf of net CO₂ per barrel produced, while the least efficient can use up to 20 Mcf/bbl.⁶⁷ This wide variation is represented in GeoCAT where assumed efficiencies across all state and geologic reservoir qualities is approximately 5 to 25 Mcf/bbl. There are 19 Mcf of CO₂ per metric ton, so in terms of weight, GeoCAT has a range of 0.26 to 1.32 tons of carbon dioxide per barrel of incremental crude oil produced by CO₂ flooding. The average is 0.53 metric tons CO₂ per incremental barrel.

⁶⁶ For example, assuming an average of 10 years of future operation at the 2016 ratios leads to a lifetime average for all historical and ongoing CO₂ EOR project of 9.09 Mcf/bbl.

⁶⁷ During the EOR operations, some CO₂ is produced with the oil and then separated and recycled back into the reservoir. "Net volume" of CO₂ is the original amount of CO₂ delivered to the EOR project, while "gross injected volume" includes both original volumes and reinjected volumes. The gross volumes are typically about twice the net volumes.

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 total cost per ton of CO₂ including all capital and operating costs. The result is a database of sequestration capacity by state, geologic reservoir type, and cost step.

Table 6-3 shows the NATCARB V storage volumes for the U.S. Lower-48 as allocated to GeoCAT categories. Total Lower-48 capacity is assessed at 8,216 gigatonnes. There are no volumes in the current model for potential storage in depleted gas field reservoirs because these are not reported in NATCARB.

For EPA Platform v6, GeoCAT represents storage opportunities in 37 of the lower 48 continental states.⁶⁸ Louisiana and Texas have both onshore and offshore state-level storage cost curves. In addition, because NATCARB does not provide state-level data, there are multi-state Atlantic offshore and Pacific offshore storage cost curves. The result is 41 storage cost curves shown in Table 6-4.

Table 6-3 Lower-48 CO₂ Sequestration Capacity by Region

		Onshore	Offshore	Total	Offshore Allocation in GeoCAT					Total
					Louisiana	Texas	GOM Total	Pacific	Atlantic	
CO2 Enhanced Oil Recovery	Low	11.2	1.1	12.3						
	Mid	15.0	1.5	16.4	1.5	0.0	1.5	0.0	0.0	1.5
	High	22.5	2.2	24.7						
Depleted Oil	Low	128.0	11.8	139.8						
	Mid	170.7	15.7	186.4	12.7	3.0	15.7	0.1	0.0	15.7
	High	256.0	23.6	279.6						
Unmineable Coal	Low	47.8	2.0	49.8						
	Mid	63.7	2.6	66.4	0.0	0.0	0.0	2.6	0.0	2.6
	High	95.6	4.0	99.5						
Saline	Low	4,252	1,708	5,960						
	Mid	5,669	2,277	7,947	1,240	798	2,038	37	202	2,277
	High	12,477	3,416	15,893						
Totals	Low	4,439	1,723	6,162						
	Mid	5,919	2,297	8,216	1,254	801	2,055	40	202	2,297
	High	12,851	3,446	16,297						
Oil Subtotal (EOR plus Depleted Oil Flds.)	Low	139.2	12.9	152.1						
	Mid	185.6	17.2	202.8	14.16	2.97	17.13	0.05	0.00	17.18
	High	278.5	25.8	304.2						

Note: Individual values may not sum to reported totals due to rounding.

The cost curves in Table 6-4 are in the form of step functions. In any given year within the IPM model, a specified amount of storage is available at a particular step price until either the annual storage limit or the total storage capacity 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 at that price step, no more storage is available going forward at that particular step price and, so, higher priced steps must be used.

⁶⁸ The states without identified storage opportunities in EPA Reference Case v6 are Connecticut, Iowa, Maine, Massachusetts, Minnesota, Nevada, New Hampshire, New Jersey, Rhode Island, Vermont, and Wisconsin. These states were either not assessed or were found to not have storage opportunities in NATCARB for the four sequestration scenarios included in EPA's inventory, (i.e., deep saline formations, depleted gas fields, depleted oil fields, and enhanced oil recovery).

CO₂ 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 Platform v6, the original CO₂ storage capacity in each storage region was reduced by an estimate of the storage that would be occupied by CO₂ generated by other industrial sector sources at the relevant level of cost effectiveness (represented by \$/ton CO₂ storage cost).

To do this, ICF first estimated the level of industrial demand for CO₂ storage in each CO₂ storage region in a scenario where the value of abating CO₂ emissions is assumed to be \$50 per ton (this abatement value is relevant not only to willingness to pay for storage but also for the cost of capture and transportation of the abated CO₂).⁶⁹ The quantity of industrial sequestration economic at \$50/ton represent the “high quality” industrial sources that have high CO₂ purity and would be easiest to capture, rehydrate, and compress. They are made up of ethanol plants, hydrogen production at refineries and merchant plants and gas processing plants where CO₂ is removed from the natural gas. This amount was calculated as 128 million tons per year.

Then, for each region, ICF calculated the ratio of the industrial demand to total storage capacity available for a storage price of less than zero dollars per ton. An upper limit of \$0.00 per ton was chosen under the belief that the earliest uses of CO₂ from industrial sources would continue the current practice of targeting EOR opportunities. Converting this quantity of capacity reserved for industrial CCS to a percent value and subtracting from 100 percent, ICF obtained the percent of storage capacity available to the electricity sector at less than zero dollars per ton. Finally, the “Annual Step Bound (MMTons)” and “Total Storage Capacity (MMTons)” was multiplied by this percentage value for each step below zero dollars⁷⁰ 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 Platform v6 November 2018 Reference Case. Thus, the values shown in Table 6-4 represent the storage available specifically to the electric sector.

The price steps in the Table 6-4 are the same from region to region. (That is, STEP9 [column 2] has a step cost value of \$9.07/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, indicating that over the modeling time horizon no new storage is being identified to augment the current storage capacity estimates. This assumption is not meant to imply that no additional storage could be added. Such additional capacity could be represented in the model if model runs exhaust key components of the currently estimated storage capacity.

6.3 CO₂ Transport

Each of the 64 IPM model regions can send CO₂ to the 41 regions represented by the storage cost curves in Table 6-4. The associated transport costs (in 2016\$/Ton) are shown in Table 6-5. For the model, ICF has also updated assumptions about the costs of CO₂ pipelines. These costs were derived by first calculating the pipeline distance from each of the CO₂ Production Regions to each of the CO₂ Storage Regions listed in Table 6-4. Since there are large economies of scale for pipelines, CO₂ transportation costs depend on how many power plants and industrial CO₂ sources could share a pipeline over a given

⁶⁹ The approach that ICF employed to estimate industrial demand for CO₂ storage is described in ICF International, “Methodology and Results for Initial Forecast of Industrial CCS Volumes,” January 2009.

⁷⁰ Zero and negative cost steps represent storage available from enhanced oil recovery (EOR) where oil producers either pay or offer free storage for CO₂ that is injected into mature oil wells to enhance the amount of oil recovered. The value of the CO₂ for EOR is calculated using the average price of crude oil of \$75/bbl taken from ICF’s Base Case forecast of mid-2018. There is also a market for CO₂ injection in enhanced coal bed methane (ECBM) production. ECBM is excluded from EPA’s inventory as discussed earlier.

distance. Consequently, the method assumes that the longer the distance from the source of the CO₂ to the sink for the CO₂, 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. CO₂ transportation cost are based on a pipeline cost of \$183,000 per inch-mile, which is consistent with ICF's natural gas supply curve and basis differential assumptions from GMM. This pipeline cost estimate is based on recent pipeline cost trends as represented in ICF's 2017 report to API entitled "U.S. Oil and Gas Infrastructure Investment Through 2030."⁷¹

List of tables that are uploaded directly to the web:

Table 6-4 CO₂ Storage Cost Curves in EPA Platform v6

Table 6-5 CO₂ Transportation Matrix in EPA Platform v6

Attachment 6-1 CO₂ Reduction Cost Development Methodology

⁷¹ See: <https://www.api.org/news-policy-and-issues/energy-infrastructure/oil-gas-infrastructure-study-2017>