NATIONAL ENERGY TECHNOLOGY LABORATORY

Coal-Fired Power Plants in the United States: Examination of the Costs of Retrofitting with CO_2 Capture Technology, Revision 3

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COAL-FIRED POWER PLANTS IN THE UNITED STATES: EXAMINATION OF THE COSTS OF RETROFITTING WITH CO_2 CAPTURE TECHNOLOGY

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Christopher Nichols, Office of Strategic Energy Analysis and Planning

LIST OF ACRONYMS AND ABBREVIATIONS

AEP	American Electric Power
Btu	British Thermal Unit = 1055 Joules
CAPEX	Capital Expense
CCM	Carbon Capture Model
CO_2	Carbon Dioxide
DOE	Department of Energy
EIA	Energy Information Administration
EV	Energy Velocity
EMM	Electricity Market Modules
FGD	Flue Gas Desulfurization
GIS	Geographic Information Systems
GW	Gigawatt
kW	Kilowatt
kWh	Kilowatt hour
LCOE	Levelized Cost of Electricity
MS	Microsoft
MW	Megawatt
MWh	Megawatt hour
NEMS	National Energy Modeling System
NETL	National Energy Technology Laboratory
NOx	Nitrogen Oxide
OPEX	Operating Expense
OSAP	Office of Systems, Analyses and Planning
Ppm	Parts Per Million
SO_2	Sulfur Dioxide
TDE	Top Decile Average Efficiency
Ton	short ton = 2000 pounds
Tonne	metric ton = 1000 kilograms
USGS	United States Geological Surv

EXECUTIVE SUMMARY

Retrofitting existing coal-fired power plants to capture CO_2 is an important GHG mitigation option for the United States. Coal power plants are large point sources and account for roughly 37% of total U.S. CO_2 emissions. Also, retrofitting utilizes the base power plant and related infrastructure and so the cost and level of disruption could be less than other greenhouse gas mitigation options.

NETL studied the 738 coal-fired generating units currently operating in the United States and estimated how much the capital cost and parasitic load for CO_2 retrofit would vary from unit to unit. Site-specific characteristics such as base plant efficiency, whether or not the unit has a sulfur scrubber, the efficiency of the sulfur scrubber, how much water is available for the unit to use, and how much space is available for the CO_2 capture and compression equipment were factored in to an estimate of CO_2 capture cost at each generating unit. These 738 units are located at 282 power plant sites (some sites/plants have more than one unit). Plant-level characteristics were applied to all the units at a power plant site.

All estimates were relative to the detailed study that NETL performed on AEP's Conesville generating station. Year 2007 amine capture technology is assumed; 90% of CO_2 in the flue gas is captured and the solvent requires 3.6 GJ regeneration energy per metric ton (mt) of CO_2 captured.

Figure ES-1 summarizes the results. The 738 generating units are ranked from least to highest cost of CO_2 capture and unit-level cost of CO_2 capture is graphed against cumulative capacity. The cost of CO_2 capture in \$/tonne (or \$/mt) avoided is calculated from the cost of electricity (COE) and the CO_2 emissions of the generating unit with and without CO_2 capture as shown below.

$$\text{Cost of } CO_2 \text{ capture} = [COE_{retrofit} - COE_{base}] / [CO_2/kWh_{retrofit,\ produced} - CO_2/kWh_{retrofit,\ emitted}] \qquad \{1\}$$

Figure ES-1 is interpreted as follows. Reading off the 75% capacity factor (CF) line, the Conesville generating plant has a cost of CO_2 capture of \$42/mt CO_2 which places it at the 30% percentile. That is, 30% of the coal fired generating capacity has a CO_2 captured cost less than \$42/mt CO_2. The other 70% of coal-fired capacity has a higher cost. Figure ES-1 shows an inflection in the curve where the cost of CO_2 retrofits begin to increase more rapidly. This inflection occurs at a capture cost of 50 \$/mt CO_2 (or equivalently 70% of cumulative capacity). Figure ES-1 also shows that a 10 percentage point change in the assumed capacity factor of the generating units changes the cost of CO_2 captured by roughly 5 \$/mt CO_2.

Avoided cost, shown in equation {2} below, is an alternative evaluation metric.

$$\text{Cost of } CO_2 \text{ capture} = [COE_{retrofit} - COE_{base}] / [CO_2/kWh_{base,\ emitted} - CO_2/kWh_{retrofit,\ emitted}] \qquad \{2\}$$

The avoided cost calculation, unlike the capture cost above, includes charges for make-up power due to net power losses associated with CO_2 capture and compression. A coal-fired generating unit with CO_2 capture using amine-based scrubbing will lose roughly 30% of its generating capacity. The cost of buying spot power to "make up" the lost capacity and also the CO_2 emissions associated with the purchased power are included in the COE and CO_2/kWh for the retrofit unit. Table ES-1 below shows the results for cost of CO_2 capture and avoided cost for the 10^{th}, 50^{th}, and 90^{th} percentiles. The avoided cost is \$40 to \$50 per mt CO_2 higher, based on a median cost for make-up power of 7.6 cents/kWh.

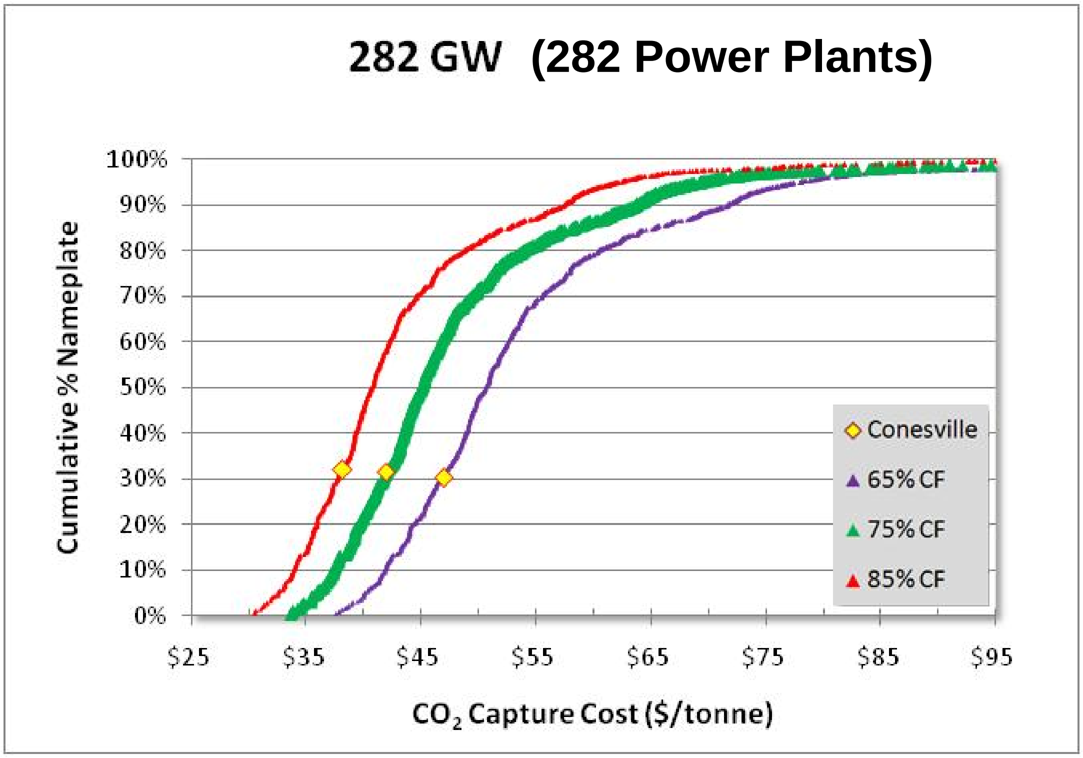


Figure ES-1. Cumulative Cost Curve, Retrofitting U.S. Coal Power Plants for CO_2 Capture

Table ES-1. CO_2 Capture Retrofit for U.S. Coal-fired Power Plants, Summary Capture Cost and LCOE results (based on 85% Capacity Factor)

	Cost of CO_2 capture ($/mt CO_2)	**Cost of CO_2 avoided ($/mt CO_2)[1]**
10th percentile	34	73
50th percentile	41	90
90th percentile	57	107

Future work includes (1) developing cost curves for cases with advanced CO_2 capture and compression technology, (2) incorporating the possibility that the retrofits for CO_2 capture include refurbishment to improve the heat rate of the base generating unit, and (3) including the

[1] Includes cost and GHG emissions for make-up power which varies by the region. Median cost value is 7.6 cents/kWh (min/max 1.1/ 9.9).

cost for CO_2 transport and injection underground, taking into account the variation in pipeline distances and the injectivity of proximate sequestration repositories.

1. METHODOLOGY

The effort compiles relevant data and maps from a number of sources into a spreadsheet based model, the Carbon Capture Model, (CCM). The CCM links the databases and calculates capital expense (CAPEX), operating expense (OPEX), and parasitic load associated with retro-fitted carbon capture technology applied to the population of coal-fired power plants in the United States.

The methodology is described in the following sections:

- 1.1 Data Sources
- 1.2 Screening Process
- 1.3 Unit-level Cost Analysis

All costs in this report are based on CO_2 at the plant gate. The cost of compression and purification to pipeline conditions are included. Not included are the cost of pipeline construction, CO_2 transport, and CO_2 injection and storage in underground geologic formations.

1.1 DATA SOURCES

This section identifies the information sources used to populate the model.

1.1.1 NETL Studies

Results from the following NETL studies were used. These reports can be found at http://www.netl.doe.gov/energy-analyses/refshelf/Default.aspx . The primary reference used is the Conesville study (listed first). The report provides the base value for the cost and parasitic load associated with implementing retrofit CO_2capture at a typical coal-fired generating unit.

- ***Carbon Dioxide Capture from Existing Coal-Fired Power Plants*** (Conesville Study) DOE/NETL-401/110907 November 2007
- ***Cost and Performance Baseline for Fossil Energy Plants***, ("Baseline Report"), DOE/NETL-2007/1281, Volume 1: Bituminous Coal and Natural Gas to Electricity, Final Report, Revision 1, August 2007
- ***Pulverized Coal Oxycombustion Power Plants*** (Oxycombustion Report), NETL, Final Results, August 2007
- ***Reduced Water Impacts Resulting from Deployment of Advanced Coal Power Technologies***, (Water Impacts Report) NETL, Chris Nichols and Phil DiPietro, December 16, 2007
- ***Water Requirements for Existing and Emerging Thermoelectric Plant Technologies***, (Water Requirements Report) NETL Kristin Gerdes and Christopher Nichols, August 2008 (April 2009 Revision)
- ***Roadmap for Bioenergy and Biobased Products in the US*** (Bioenergy Roadmap study), Biomass Research and Development Technical Advisory Committee, 2009

1.2.2 Generating Unit Characteristics

The primary source of data on physical plant parameters such as unit nameplate capacity, heat-rate, and emissions was obtained from Ventyx Corporation's Energy Velocity (EV) Suite, a compilation of energy industry and market databases. Appendix 1 provides a detailed description of the EV data elements that were used in the database. The database contains ten years of historical data. To provide a more valid representation of plant operations, the model uses ten-year average values for, heat rate, operations, and emissions data. EV data was joined to NETL's Coal-fired Power Plant database (http://www.netl.doe.gov/energy-analyses/refshelf/PubDetails.aspx?Action=View&PubId=310) to provide steam pressure for the analysis.

1.1.3 Arial Imagery of Power Plant Sites

The Microsoft TerraServer-USA Web site was used both as a primary source of power plant imagery and as a base map on which to georegister more recent or higher resolution imagery if available through Google Maps. The MS Terraserver imagery is available as an open-source Windows Mapping Service and as a seamless imagery layer within ESRI ArcGIS. Maps and images are supplied to Terraserver through Microsoft's partnership with the U.S. Geological Survey.

Figure 1-1 shows an example of available MS Terraserver imagery of Plant 1726 AES Somerset in Barker, New York. Of the 324 plants analyzed for this effort, 250 had satisfactory (best available) imagery obtained through MS Terraserver.

Google Maps often provided the most recent, highest resolution imagery for sites in the project. Figure 2-1 presents an example of available Google Maps imagery from Plant 2351, Gulf Power Co Christ Plant in Pensacola, Florida. Google Maps is not available as an open-source Windows Mapping Service, requiring screen capture and georegistration, processes which were performed for this project. Note the color, screen-captured Google Maps imagery georeferenced to the underlying, black and white Terraserver imagery. Of the plants analyzed for this project, 40 had the best available imagery through Google Maps.

Figure 1-1. Example MS Terraserver Imagery

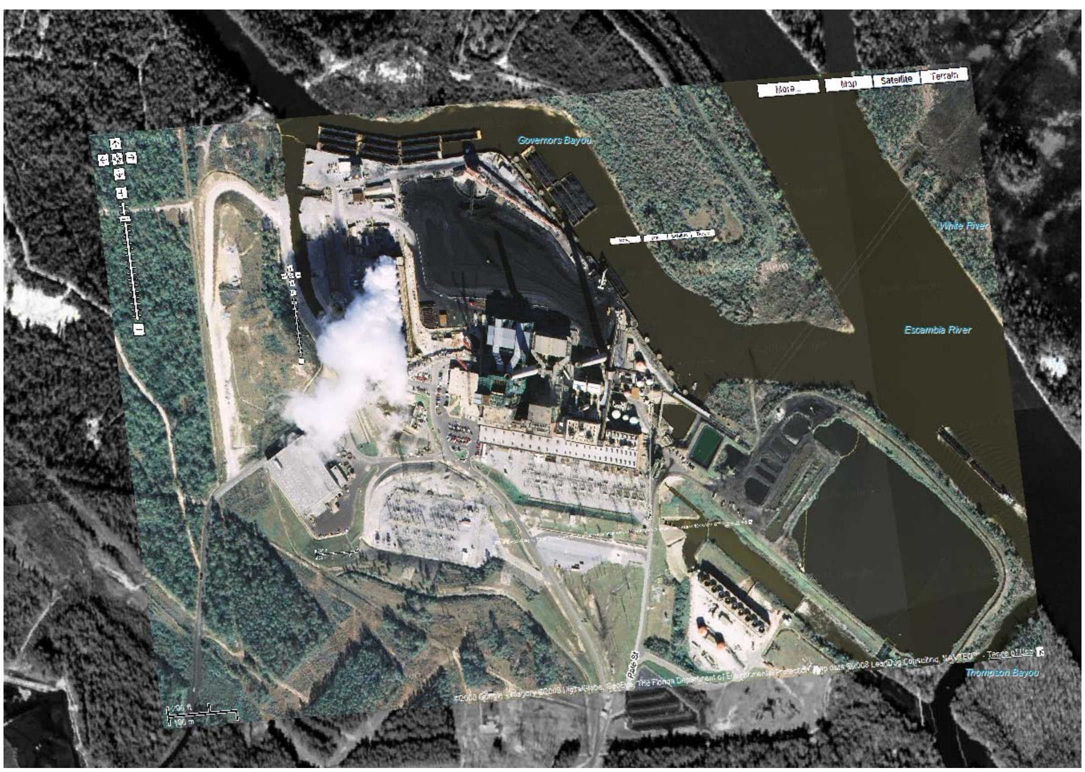


Figure 1-2. Example Google Maps Imagery (color) on a Terraserver Image Base

1.1.4 Water Availability

Due to increased cooling loads associated with amine-based CO_2 capture and compression, up to 100 percent increase, additional cooling water sources will be required upon retrofitting an existing unit. Depending on the current power plant cooling technology and location within the U.S., there is a potential for significant water constraints to meet additional capture and compression cooling needs.

Data on the renewable water supply was provided by the U.S. Geological Survey (USGS), 1984, *National Water Summary 1983—Hydrologic Events and Issues: U.S. Geological Survey Water-Supply Paper 2250*. Renewable water supply is defined as the sum of precipitation and imports of water, minus the water not available for use through natural evaporation and exports. Renewable water supply is a simplified upper limit to the amount of water consumption that could occur in a region on a sustained basis. Figure 1-3 shows the USGS water availability data.

The Bioenergy Roadmap study was used as a data source on the status of fresh water aquifers to further define those geographic areas with stressed or overpumped aquifers. Figure 1-3 shows these overpumped aquifers in relation to the USGS water availability data. These data were used to identify those plants in areas where further withdrawal from local aquifers is problematic.

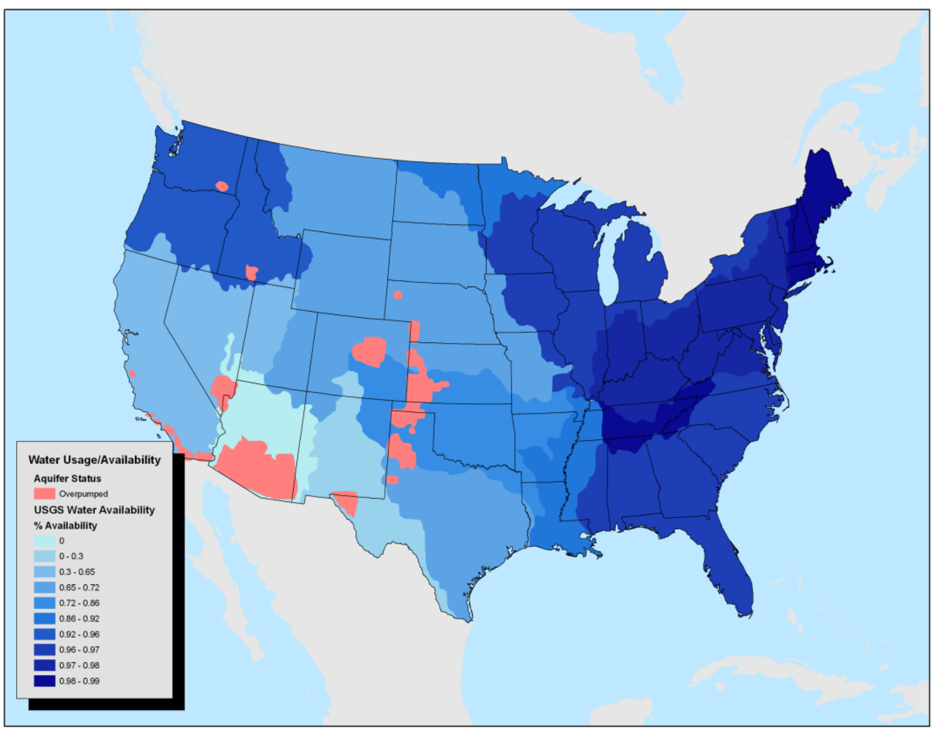


Figure 1-3. Water Availability

1.1.5 Potential CO_2 Storage Repositories

GIS data on saline aquifers acceptable for carbon sequestration and the network of existing CO_2 pipelines was obtained from NETL's NatCarb website www.natcarb.org. Figure 1-4 shows these data.

GIS data on existing oil and gas production was obtained from the USGS. A comprehensive, nation-wide GIS polygon set of oil and gas fields are not readily available. The USGS has published an oil and gas production map of the United States. This dataset consists of over one million ¼ mile cells attributed with the presence of oil production, gas production, oil and gas production, or dry field. Figure 1-5 shows the USGS oil and gas data.

Data were available from NatCarb on volumes of CO_2 able to be sequestered in oil and gas fields and saline aquifers. These data were compiled to calculate a total sequestration capacity density map. Figure 1-6 shows sequestration quality in units of millions of tonnes CO_2/ km^2. It should be noted that not all areas identified in the NatCarb and USGS sequestration opportunity datasets are shown as having sequestration capacity, which leads to differences between the two data sets. This source was used to evaluate storage space availability only, and not the costs associated with storage and measurement, monitoring and verification.

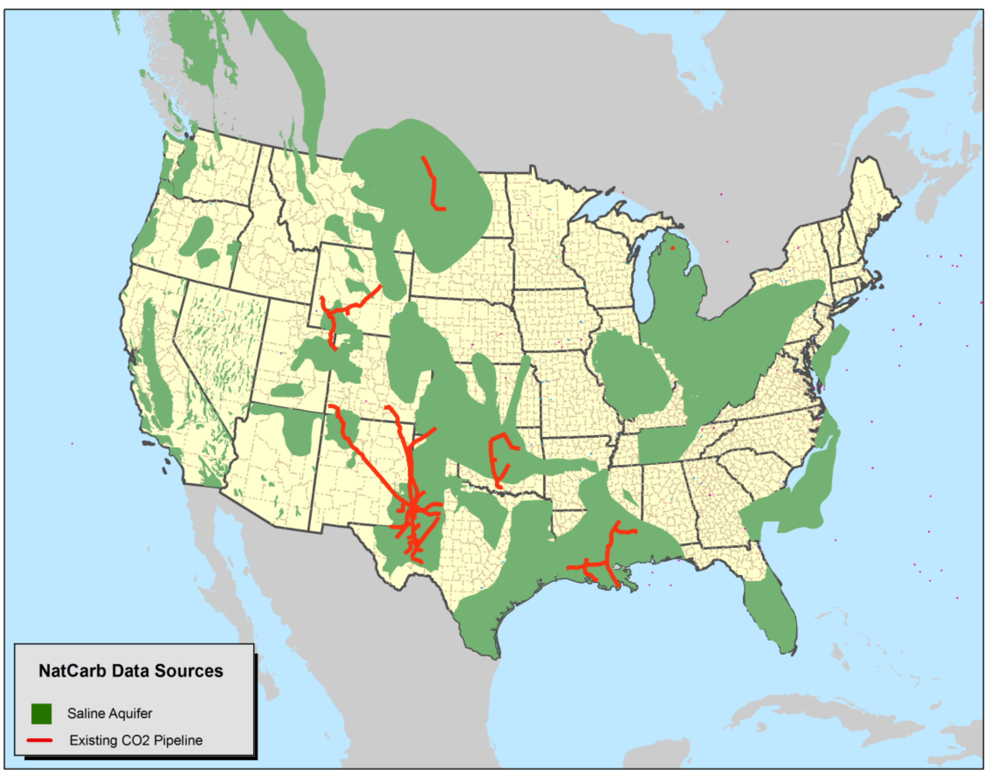


Figure 1-4. NatCarb Datasets

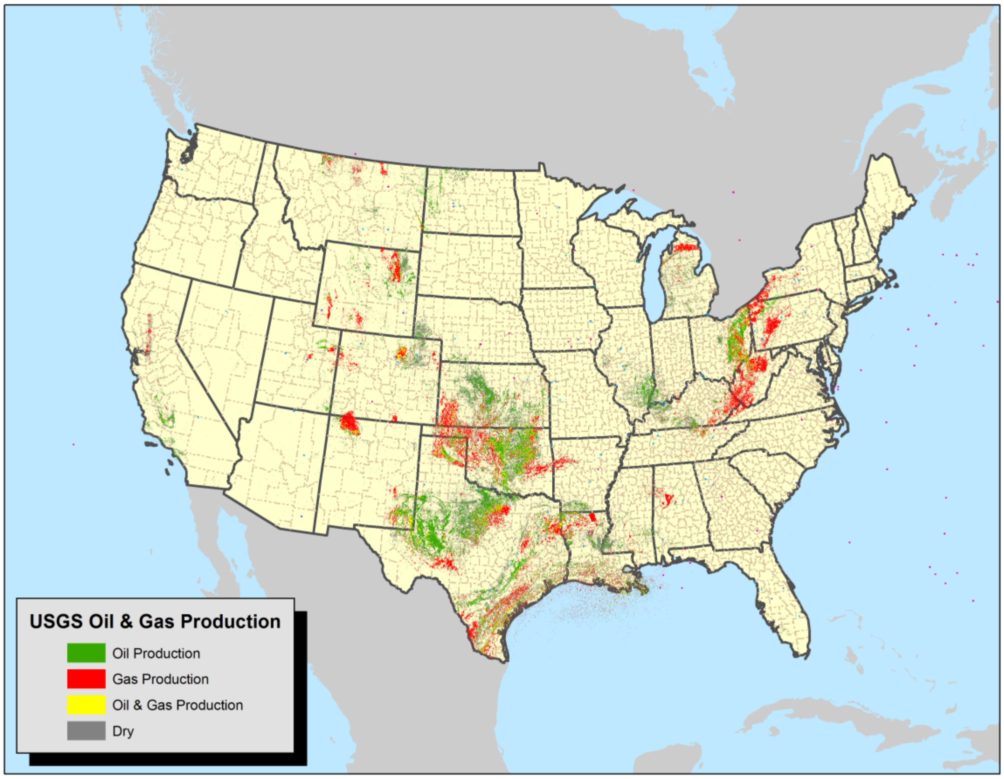


Figure 1-5. USGS Oil and Gas Production Dataset

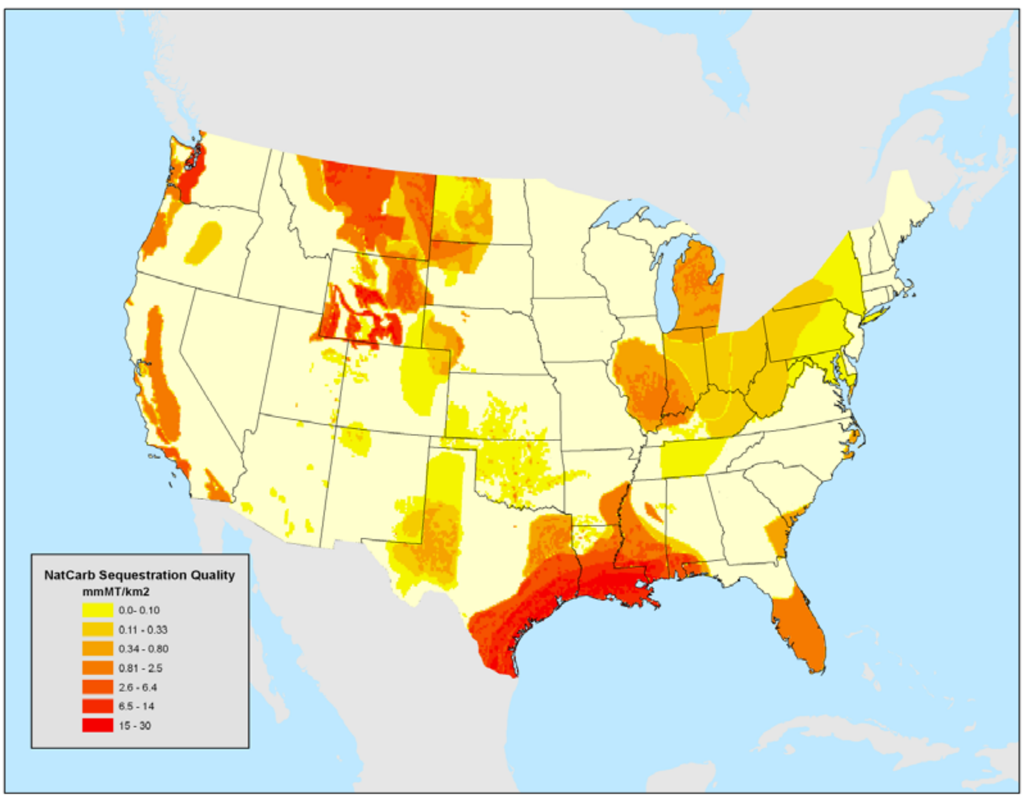


Figure 1-6. NatCarb Sequestration Quality

1.1.6 Price Projections for Commodity Power

Because the generation profile in a carbon-constrained world would significantly differ from the current power generation makeup, the CCM uses projections created by NETL to represent a likely generation profile following passage of the proposed Waxman-Markey climate change legislation.

"The American Clean Energy and Security Act of 2009", sponsored by Congressmen Waxman of California and Markey of Massachusetts (Waxman-Markey) passed in the U.S. House in June, 2009. The Waxman-Markey bill addressed many issues related to climate change, but required a 17 percent reduction in greenhouse gas emissions, from 2005 levels, by 2020, and an 83 percent reduction by 2050. The bill also required utilities to obtain 15 percent of their electricity from renewable sources, by 2020; and to demonstrate annual electricity savings from efficiency measures.

Figure 1-7 shows the price for purchased power and the associated GHG emissions. There is a wide variation geographically so regional data from the NEMS Electricity Market Modules (EMM) were applied using GIS polygons. NETL ran NEMS using the EIA's Waxman-Markey scenario to generate the average emissions rates and electricity prices by EMM region for the year 2020. Figure 1-8 shows assumed carbon loading that were inputs into the NEMS model and also regional generation results.

Figure 1-7. Forecast Regional Price and GHG Emissions for Power in 2020 under a GHG Emissions Reduction Scenario Emulating the Waxman-Markey Bill

EMM Region	Emissions rate (tonnes/MWh)	Electricity price ($/kWh)
1	0.797	0.076
2	0.605	0.079
3	0.451	0.087
4	0.493	0.067
5	0.656	0.056
6	0.301	0.099
7	0.243	0.081
8	0.438	0.011
9	0.544	0.067
10	0.826	0.076
11	0.296	0.043
12	0.712	0.082
13	0.278	0.073

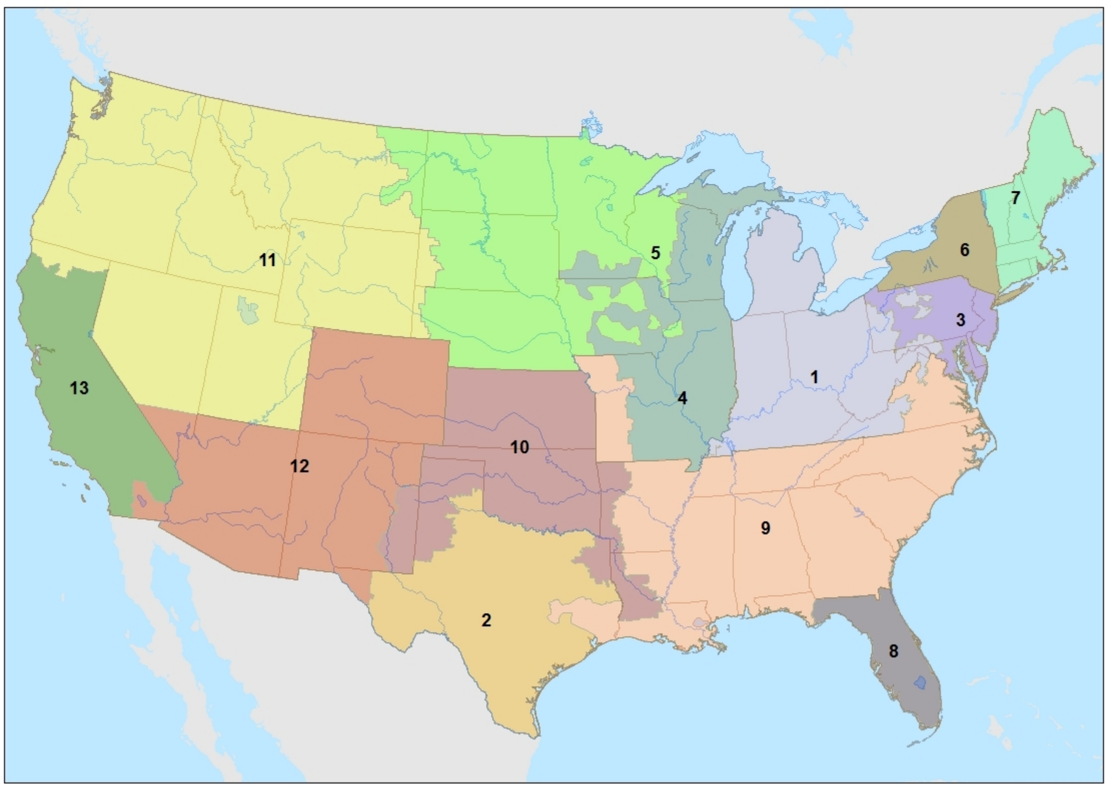
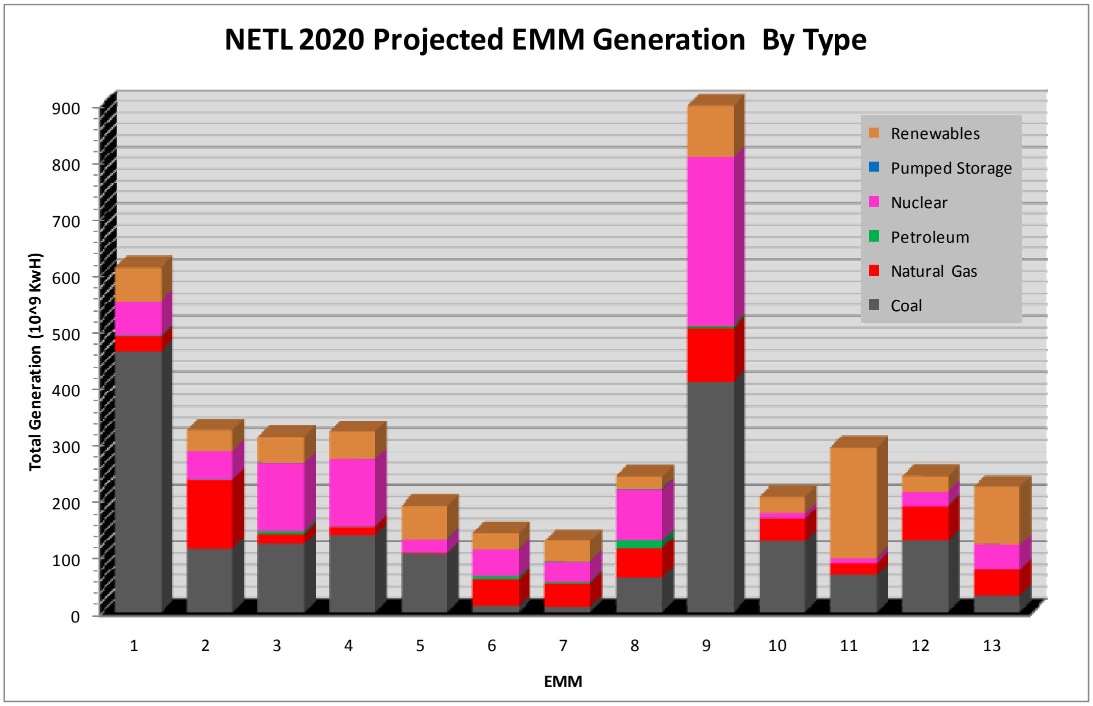


Figure 1-8. Forecast Generation by Region in 2020 under a GHG Emissions Reduction Scenario Emulating the Waxman-Markey Bill and Carbon Loading by Generation Type.



Type	Associated Carbon Loading (g/KwH)
Coal	909
Petroleum	821
Natural Gas	465
Nuclear	6
Pumped Storage	4
Renewables	-

1.2 SCREENING PROCESS

Prior to performing the cost analysis, a portion of the population of coal-fired power plants was screened out as being not amenable to CO_2 capture retrofit. Plants excluded were those that:

- are not currently operating
- have a capacity less than 100 MW
- have a 2008 reported heat rate greater than 12,500 Btu/kWh
- do not have a defined CO_2 repository within 25 miles.

Figure 1-9 shows the screening criteria applied to the population of power plants. The left panel shows number of plants and the right panel shows generation capacity. Fifty percent of the operating power plants were excluded from the analysis, primarily consisting of smaller plants representing only 15% of the total generating capacity.

The screening process was conducted at the plant level. A “power plant” is a parcel of land where coal is turned into power, and a single power plant may contain more than one generating unit. The capacity screen is based on the total capacity of all the generating units at a site. The idea being that one CO_2 capture facility could serve all the units and thus obtain the needed economies of scale. The heat rate metric used as a screen is the average heat rate of all the units operating at a site.

The current analysis considers neither the injectivity nor CO_2 storage capacity, only the distance from a potential long term storage source to screen plants. A parallel task being conducted by NETL aims to develop information on the “quality” of sequestration targets. That data will be incorporated into subsequent versions of this analysis and will likely serve to exclude more power plants as not being near enough to large and permeable sequestration targets.

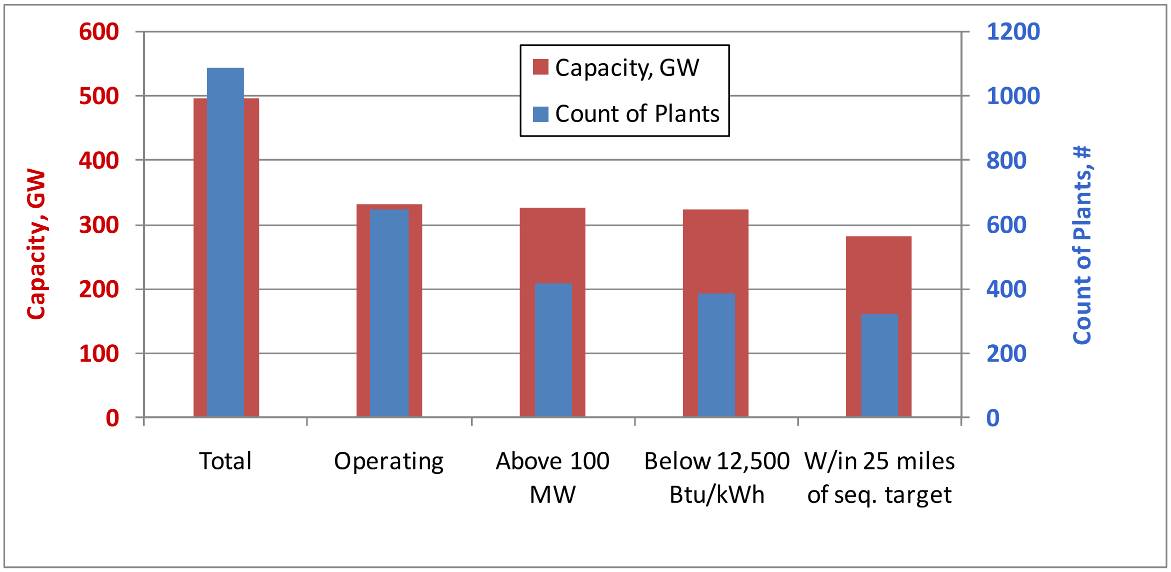


Figure 1-9. Results of the Screening Process

1.3 UNIT-LEVEL COST ANALYSIS

This section describes the analysis methodology used to make the unit-level adjustments to the cost and energy penalty associated with CO_2 capture retrofit. The following is a list of adjustments. Each is described below.

- Scale the let-down turbine and the CO_2 separation and compression equipment relative to Conesville
- Add sulfur scrubbing and polishing to 10 ppm
- Reduce NOx to 0.07 lbs/mmBtu coal
- Upgrade to re-circulating cooling or, in arid areas, upgrade to dry cooling
- Add cost adjustment for units where the unit operations (boiler, steam turbine, etc.) are tightly spaced relative to Conesville (0-40% adjustment applied to CO_2 scrubbers, CO_2 absorbers, sulfur scrubbers, and sulfur polishers)
- Add cost adjustment for generating units where the CO_2 retrofit will require moving coal piles, parking lots, or other structures (0-40% adjustment applied to CO_2 compression and cooling towers). This includes the cost of purchasing extra land where possible.
- Apply economies of scale discount for multiple units at the same plant (4% applied to all costs)

The adjustments are relative to the design set forth in the Conesville Study. Figure 1-10 is an aerial view of the Conesville generating station with the CO_2 capture and compression equipment drawn in consistent with the plot plan in the CO_2 retrofit design document. Notice the large footprint for the CO_2 compression facility and how far away it is from the CO_2 absorber.

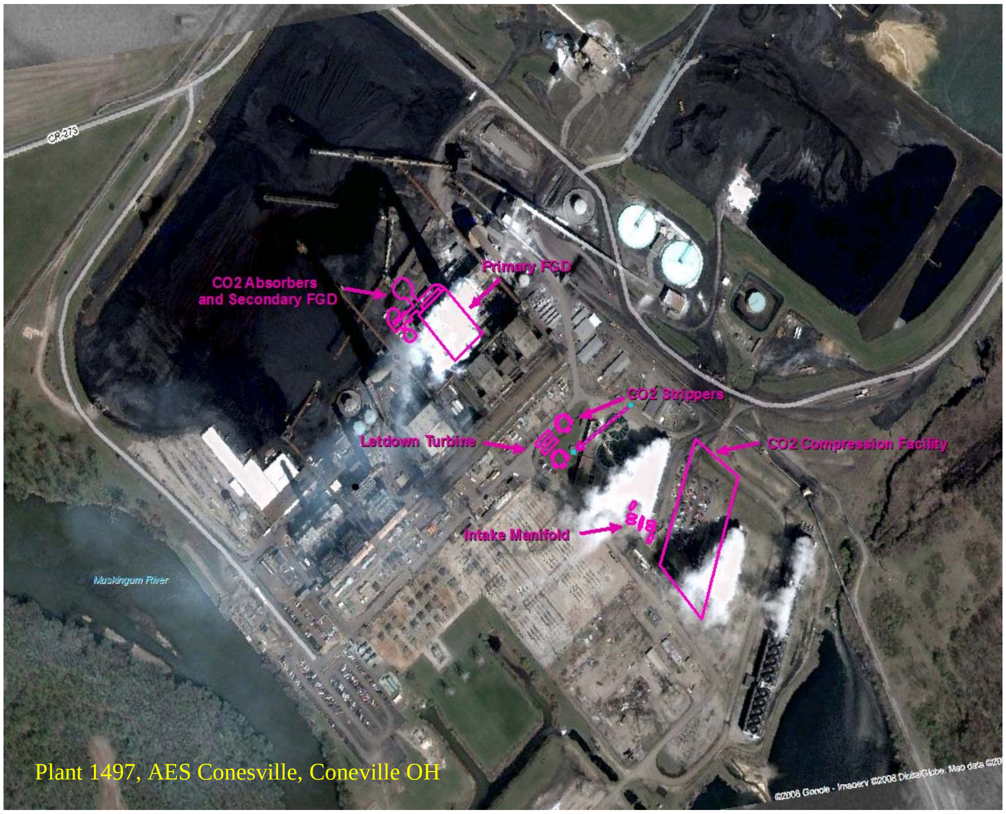


Figure 1-10. Aerial imagery of the Coneseville plant

Scale Adjustments

The Conesville Study examined four cases with CO_2 capture percentages of 90, 70, 50 and 30 percent. The study's cases were achieved by limiting the amount of flue gas diverted to the CO_2 absorbers—which allowed an imputed calculation of power plant size if the equipment for each of the cases was operative at 90 percent capacity. For example, scrubbing 50 percent of the CO_2 from a 435.5 MW Conesville Unit 5 is the equivalent of scrubbing 90 percent of the CO_2 from a 242 MW unit. Best fit lines were developed from the Coneville data points, Figures 1-11 and 1-12, and applied to estimate the capital cost of CO_2 retrofit at each unit based on its starting nameplate generating capacity. Figure 1-13 presents an estimated cost for the CO_2 scrubber. This cost was not presented in the Conesville Study, but rather bundled with the compressor cost. The capture and compression costs were separated to properly apply the adjustments for close-in and landscape space availability.

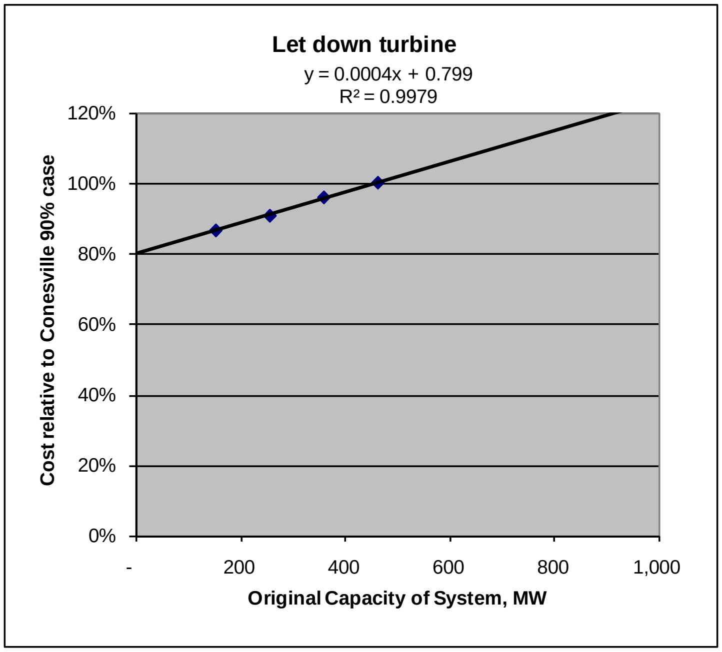


Figure 1-11. Let-Down Turbine Cost and Size Scaling

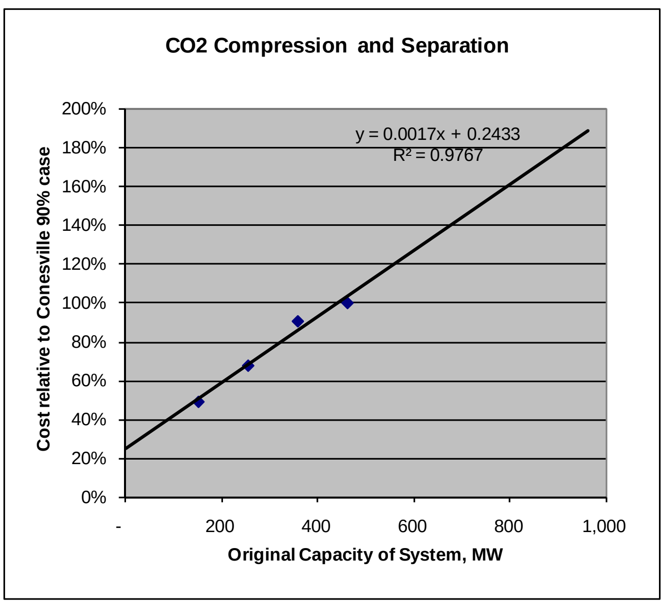


Figure 1-12. CO_2 Separation and Compression Cost and Size Scaling

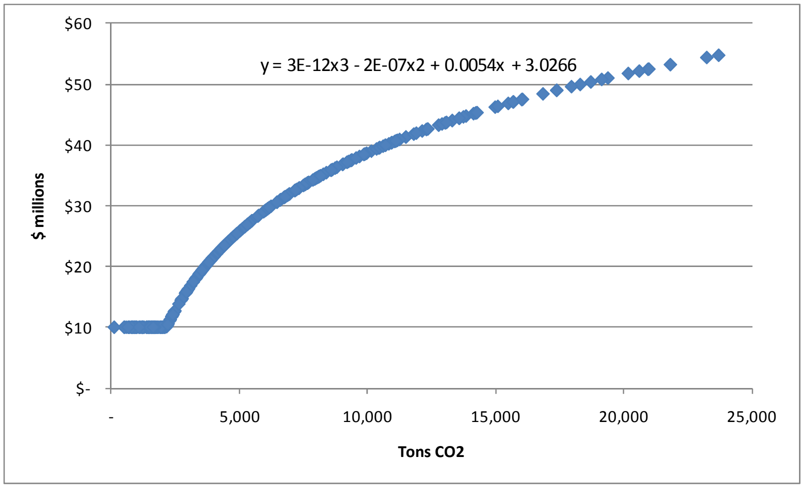


Figure 1-13. CO_2 Scrubber Cost and Size Scaling

1.3.1 SO_2 Removal

In plants without primary FGD systems, new construction costs of $230 per kilowatt capacity for the primary FGD system designed to remove 98 percent SO_2, and a value of $94.60/ton[2] for the additional sulfur removed by sulfur polishing down to 10 ppm were used. An example is Conesville's 841.5 MW Unit 3, currently without primary FGD. At a cost of $105.5/kW, the Conesville Unit 3 FGD would cost $88.5 million for installation of FGD.

In plants with current primary FGD systems, the current SO_2 removal percentage was estimated using emissions and coal data from the EV datasets. The marginal SO_2 removal needed to achieve 98 percent was calculated and the marginal additional removal requirement was prorated at a cost of $216 per kilowatt capacity. The sulfur polishing cost of $94.60/ton was then applied to the additional sulfur reduction to 10 ppm. Again, the Conesville report was used as the basis for scaling the various SO_2 removal processes to each plant as necessary. A cost of $17.5 million, based on calibration with Conesville Unit 5, was used as a minimum cost of sulfur polishing.

1.3.2 NOx Removal

Consistent with the post-combustion CO_2 capture cases contained in the 2008 NETL Oxycombustion Report, and to be compliant with environmental requirements, the CCM requires NO_x emissions to be at or below 0.07 lbs NO_x/ million Btu for purposes of CO_2 capture. NO_x emissions data for each unit was compared to this target rate to determine

[2] Estimated from Baseline Report.

the additional NO_x scrubbing requirement. Using the unit's total Btu value and an installation cost of $300/tonne NO_x, a value for NO_x scrubbing cost was calculated.

1.3.3 Recirculating Cooling

The analysis is based on an assumption that all plants will be converted to recirculating cooling as part of the retrofit process. The exception is power plants that are located in arid areas. In those cases, a dry cooling system will be installed as a part of the retrofit process. The 2007 NETL Conesville Study did not address the issue of additional cooling capacity required by the CO_2 retrofit. Current amine-based CO_2 wet-scrubbing technology requires cooling to maintain the appropriate reactor temperatures. Multi-stage CO_2 compression also requires cooling. Based on the Water Requirements Report, it was determined that a retrofitted unit would require 30 percent more recirculating cooling capacity than an unretrofitted unit. The total area (in square meters) of recirculating, induced draft cooling towers currently installed at the unretrofitted Conesville Unit 5 was digitized from the GIS imagery. This area was then increased by 30% to represent the area (and inferred required capacity) of the retrofitted Conesville Unit 5. This area was then divided by the total btu/hour generated at Conesville Unit 5 to arrive at a factor of required square meters of recirculating cooling per btu per hour. This methodology provided more required cooling at units operating at higher heat rates. This required area of retrofitted cooling is compared to the area of currently installed cooling towers (if present) to determine the area of additional cooling required.

Using this ratio, polygons representing the estimated additional cooling for the Conesville plant were created. Figure 1-14 shows the current and additional recirculating cooling needed to retrofit all units at Conesville.

Using a unit's nameplate capacity, heat rate, an estimation of the heat generated per hour by a unit was calculated to determine a needed cooling area/Btu/hr for retrofitted units. A plant's current cooling area was digitized in the GIS and used to calculate additional cooling area needed.

The CAPEX cost of the additional recirculating cooling at the Conesville plant was identified as $2.85 million.[3] This value was compared to the total area of additional cooling to calculate a cost per square meter of recirculating cooling. This rate was used to estimate recirculating cooling costs at other plants.

Consideration was also given to the fact that some plants may require dry cooling due to local water availability. Based on the Water Requirements Report, a factor of 3.5 times the cost of recirculating cooling was applied to those plants identified as needing dry cooling.

Cooling costs were modified using the USGS water availability data (see Figure 1-3). Watersheds were assigned a water availability factor of 1 (minimum) to 3 (maximum)

[3] Estimated from the Baseline Study CAPEX costs.

relative to the water availability for Ohio (where the Conesville plant is located). By this methodology, cooling in plants in the driest areas (but where water is still available for recirculating cooling) will cost three times that of the cooling system at the Conesville plant. This factor was implemented and applied to water recirculating facility costs to account for additional cost of securing water for a plant (such as drilling wells).

It was determined that a plant would require dry cooling if it was located in one of the two most-arid USGS watersheds, or if it was located within one of the areas designated as having an overpumped reservoir west of the Mississippi River (see Figure 1-3).

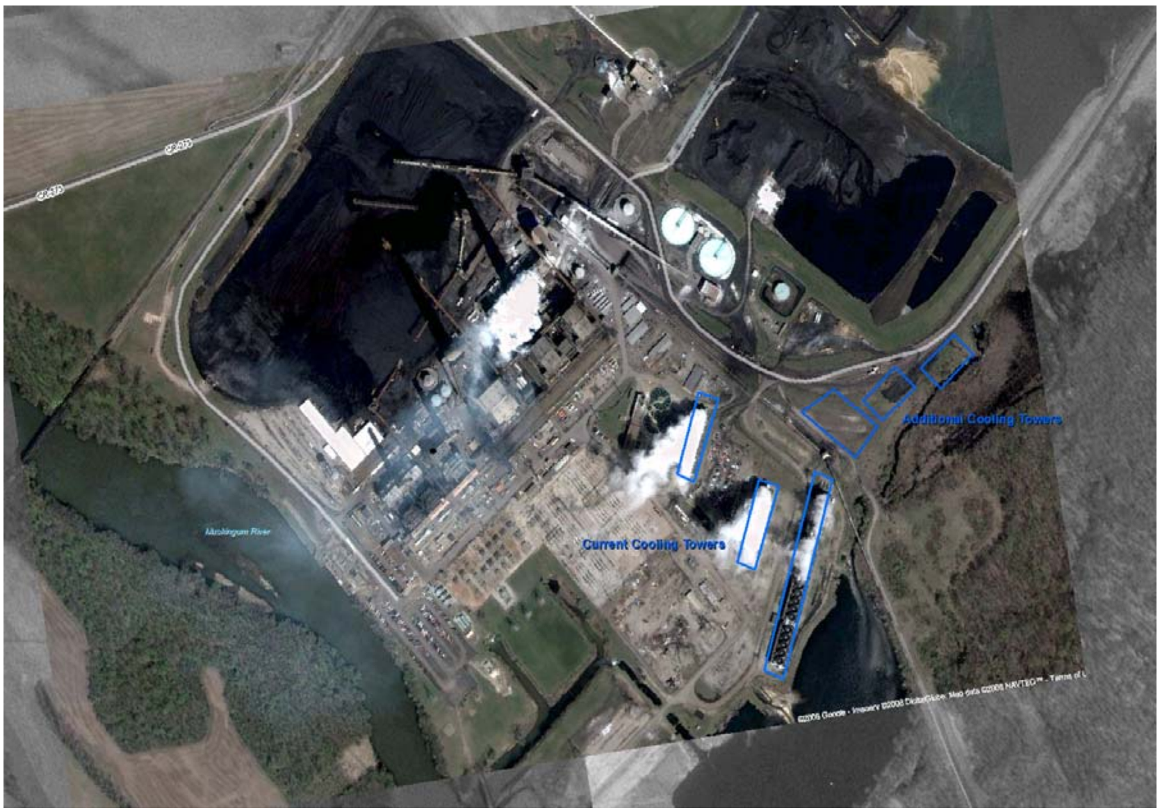


Figure 1-14. Current and Additional Recirculating Cooling Required to Retrofit All Units with 90% CO_2 Capture and Compression at the Conesville Plant

1.3.4 Discounted Incremental Plant Units

A total CAPEX discount of 4 percent was given to plants with multiple units to account reduced engineering costs and economy of scale. The discount was determined by assuming a 50 percent reduction in engineering costs for the first successive unit at a site and was calculated based upon engineering costs in the Conesville Study relative to total investment costs.

1.3.5 Construction Difficulty Factors

In analyzing the sampled plant sites it became apparent that some plants have less available space for equipment than others. Two construction cost factors were determined to accommodate this situation—a “close-in” cost of construction difficulty factor and a “landscape” cost of construction difficulty factor. A complete retrofit of Conesville Units 4, 5, and 6 was modeled using the Conesville Study as a guide. Conesville then served as a baseline for comparison of retrofit difficulty at other plants. Figure 1-15 shows the AEP Conesville plant retrofitted with carbon capture equipment on its three operating units. In this figure and the following figures, pink outlines represent additional CCS equipment, dark blue represents existing cooling and light blue new required cooling structures.

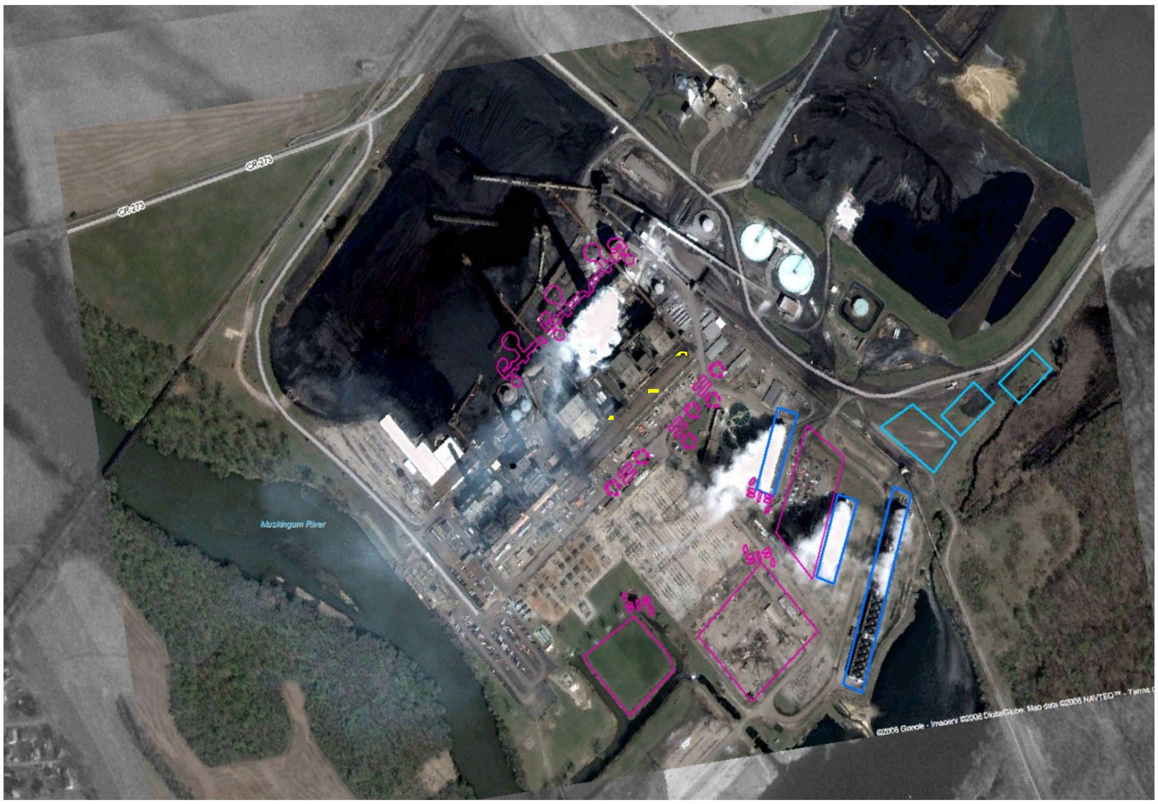


Figure 1-15. Complete Plant Retrofit

Close-in Construction. The letdown turbine, CO_2 scrubbers and absorbers, as well as the primary and secondary FGD’s require construction in close proximity to the turbine and flue stack. The layout of some plants can easily accommodate these additional components. However, for plants where space is more crowded, an incremental factor was applied to account for anticipated difficulty in construction. These factors ranged from 0 (easily constructed) to 40 percent (difficult to construct). Plants with a zero factor are assumed to have a construction difficulty comparable to the Conesville baseline plant. This factor was added to one and used to scale costs.

Landscape Construction. At the Conesville plant, as depicted in 5, designs were created to individually retrofit Units 4, 5, and 6 with all required components. However, it was assumed that CO_2 compression and additional cooling facilities could be combined into larger plant (as opposed to unit) -servicing components. Note that, while some adjustments and accommodations will need to be made, there are no large structures or other significant obstacles to overcome or work around with close-in construction at the Conesville site. The CO_2 compression facility and additional cooling towers can be built in proximity to the plant, allowing more latitude for siting them. Still, these components are by far the largest and require significant open space at a plant.

Using the Conesville plant as a baseline, each plant analyzed in the viable population was assigned close-in and landscape construction incremental difficulty factors ranging from 0-40 percent. These values are based on professional judgment and represent general increases in costs due to engineering and construction difficulties.

Figure 1-16 shows Plant 2315 Cherokee in Denver, Colorado, a plant assigned a 10 percent close-in construction difficulty. The primary difficulty at this four-unit plant is the CO_2 scrubbers. One scrubber interferes with a cooling tower and another interferes with other structures. The plant required no primary FGD, and appears to have sufficient recirculating cooling to accommodate retrofit, based on an analysis of cooling system data. The coal pile and a cooling tower must be moved, resulting in a 10 percent landscape construction difficulty.

Figure 1-17 shows Plant 1651 Potomac River in Alexandria, Virginia, a plant assigned a 30 percent close-in construction difficulty. Note that primary FGDs and CO_2 scrubbers need to be constructed against the river, and the letdown turbines and CO_2 absorbers may require moving the substation. This plant was also assigned a 10 percent landscape construction difficulty because of conflicts with the coal pile and the parking lot.

Figure 1-18 shows Plant 1660 John Amos in Charleston West Virginia, which was not assigned additional construction difficulty.

Figure 1-19 shows Plant 2346 Crystal River in Crystal River, Florida. It was assigned a 15 percent close-in construction difficulty due to the southern CO_2 scrubbers and let-down turbines. It was not assigned a landscape construction difficulty.

Figure 1-16. Example Showing 10 Percent Close-In Construction Difficulty and 10 Percent Landscape Construction Difficulty

Figure 1-17. Example Showing 30 Percent Close-In Construction Difficulty, 10 Percent Landscape Construction Difficulty

In some cases, it may be cheaper to purchase more land rather than engineer around a crowded plant site, or a site may simply be too crowded such that additional land may be required to accommodate the retrofit facilities. This is particularly true for landscape construction components. Using the EV Land and Rights data as an analog for land value, and the estimated total plant acreage from the GIS, a dollar per acre value was estimated for additional land cost. Where Land and Rights data was not available, a value of $5,000/acre was used. It should be noted that the plant boundary can only be inferred from a best-judgment analysis of the available imagery. In some cases, the plant boundary is relatively clear, but typically assumptions must be made. Addition of a land records GIS database to the model could mitigate these assumptions and better quantify land value, but would require efforts beyond the scope of this project.

Figure 1-20 shows Plant 1779 Warrick in Newburgh, Indiana. A parcel totaling 19.2 acres was added to accommodate the landscape retrofit components.

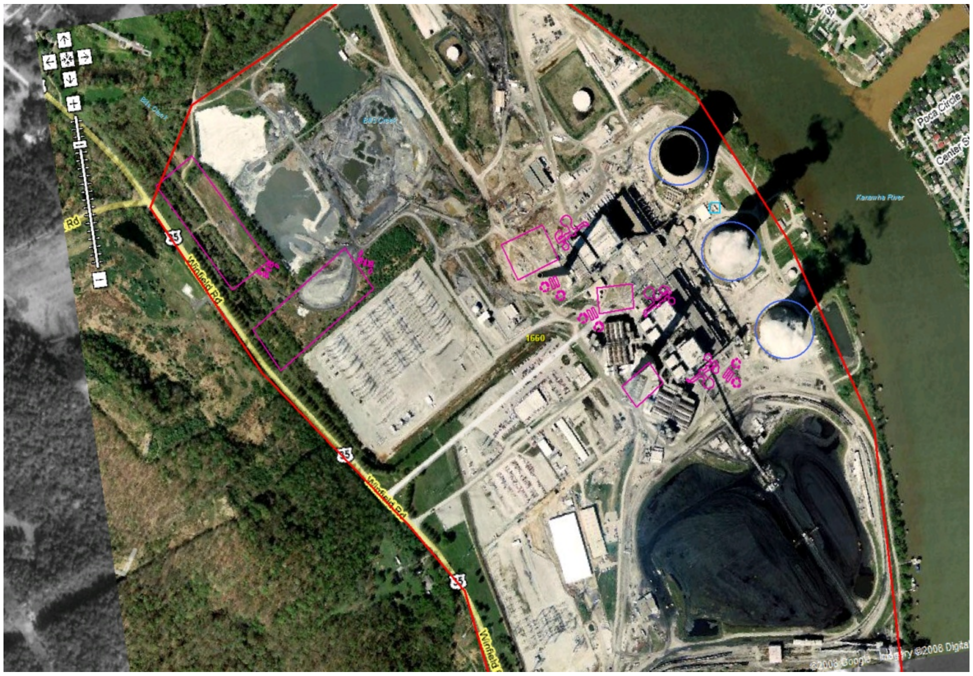


Figure 1-18. Example Showing 0 Percent Close-In Construction Difficulty, 0 Percent Landscape Construction Difficulty

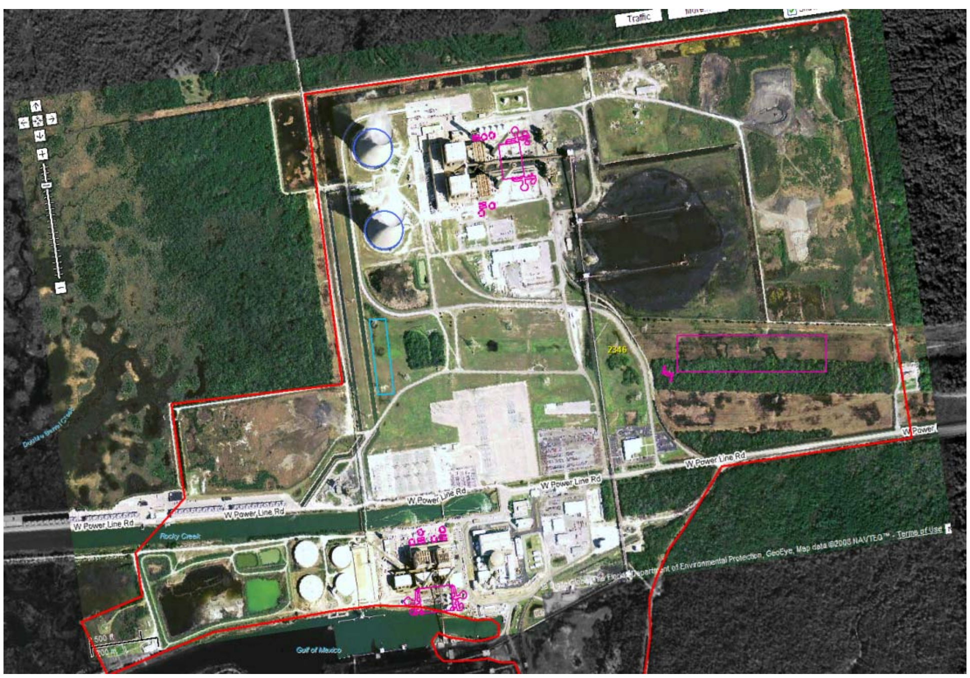


Figure 1-19. Example Showing 15 Percent Close-In Construction Difficulty, 0 Percent Landscape Construction Difficulty

Figure 1-20. Additional Land Requirements

Figure 1-21 shows how many plants were assigned correction factors. More adjustments were made for close in space limitations than for landscape

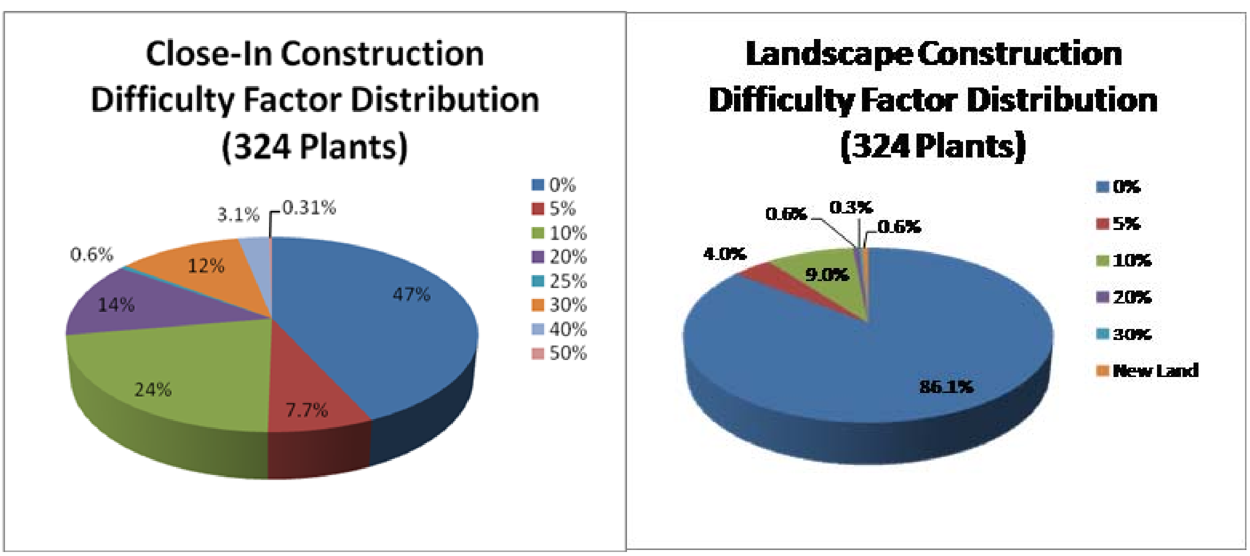


Figure 1-21. Assigned correction factors for space limitations

1.3.6 Total Investment CAPEX

In the model, Total Investment CAPEX for a generating unit is determined as follows:

CX_{TOT} = [(CX_{LD} +CX_{CS} + CX_{SR} + CX_{NO})*AF_c* + (CX_{CC} +CX_{CW})*AF_L]*AF_{MU} + CX_{AL}

CX_{LD} = 0.004 * MW + 0.8

CX_{CS} = $3x10^{-12}$ * $(MW)^3$ + $2x10^{-7}$ * $(MW)^2$ + 0.0054 * (MW) + 3.03

CX_{SR} = CX_{SS}+ CX_{SP}

CX_{SS} = if FGD then (0.98 – N_{ss})*MW*216 $/kW, else MW*230 $/kW

CX_{SP} = (1-0.98)*MW*HR*(1/CL_{HC})*CL_{SU} * 95 $/ton sulfur

CX_{NO} = if NO_x < 0.07 then 0 else (NO_X - .07) lbs/mmbtu *HR*MW*8760*CF*20 yrs*300 $/mtNOx

CX_{CW} = MW * [if ARID then (if dry_cooling then 0 else MW * 98 $/kW) else (if recirc_cooling then 0 else 28 $/kW)]

CX_{CC} = 0.0017 * MW + 0.24 - CX_{CS}

where:

MW = unit nameplate generating capacity, MW

HR = unit heat rate, average achieved between 2000 and 2008, btu/kWh

CX_{TOT} = total capital expense for CO_2 retrofit, MM$

CX_{LD} = capital expense for the let down turbine, MM$

CX_{CS} = capital expense for the CO_2 capture and separation

CX_{SR} = capital expense for sulfur scrubber/upgrade to existing sulfur scrubber

CX_{SS} = capital expense for primary sulfur scrubber

CX_{SP} = capital expense for sulfur polishing

CX_{NO} = capital expense for NO_x reduction/upgrade to existing NO_x reduction

CX_{CC} = capital expense for CO_2 compression

CX_{CW} = capital expense for cooling water upgrade

CX_{AL} = capital expense for additional land

AF_C = adjustment factor for tight spacing within the unit (close in)

AF_L = adjustment factor for tight spacing surrounding the unit (landscape)

AF_{MU} = adjustment factor (discount) for multiple generating units at a single plant

N_{ss} = efficiency of the scrubbing unit (SO_x captured)

NO_X = NO_x emissions, tons/yr

CL_{HC} = coal heat content, btu/lb

CL_{SU} = coal sulfur content, wt%

1.3.7 OPEX

In the CCM, OPEX is calculated as the sum of Fixed (Labor) cost, Variable (chemical, waste, and maintenance) costs, and Feedstock cost. Figures 1-22, 1-23, and 1-24 show these costs as a function of the generation capacity of the power plant based on the scenarios in the Conesville Study. Note that the relationship between feedstock cost and nameplate, in Figure 1-26, does not fit a function well, but does show a general trend. This relationship is not completely understood.

The Conesville Study gives OPEX as functions of total CO_2 captured. For the 90% capture scenario, a retrofitted Conesville Unit 5 would capture approximately 3.3 million tons of CO_2 per year and would require $2.6 M per year in fixed OPEX, $22.3 M per year in variable OPEX, and $1.1 M per year in feedstock OPEX.

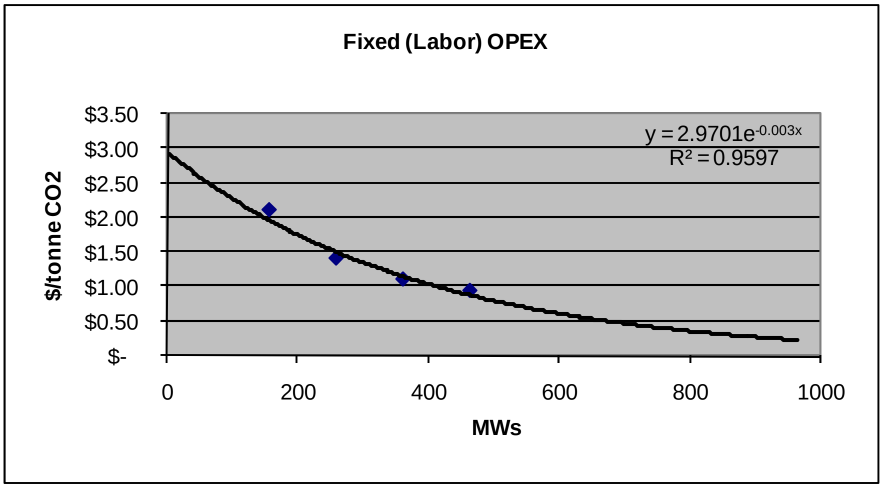


Figure 1-22. Fixed OPEX Cost Function

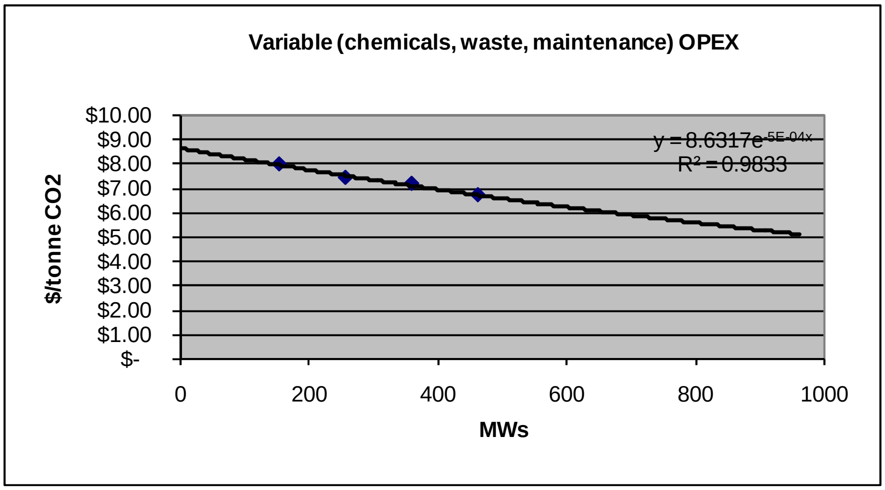


Figure 1-23. Variable OPEX Cost Function

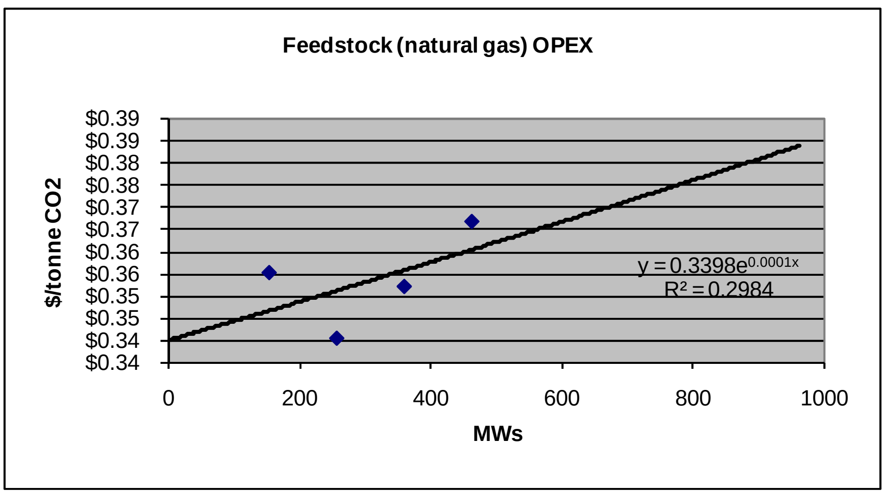


Figure 1-24. Feedstock OPEX Cost Function

1.3.8 Parasitic Load

The total parasitic load of the carbon capture retrofit is equal to the sum of the parasitic loads of the newly installed NOx and SO_2 control equipment, the additional cooling, the actual CO_2 retrofit components, the parasitic heat used for amine regeneration and compression. Energy requirements for transportation, storage and monitoring were not included in this analysis.

A parasitic loading function was developed based on the Conesville Study cases for the retrofit equipment. Figure 1-25 shows this as a function of nameplate capacity.

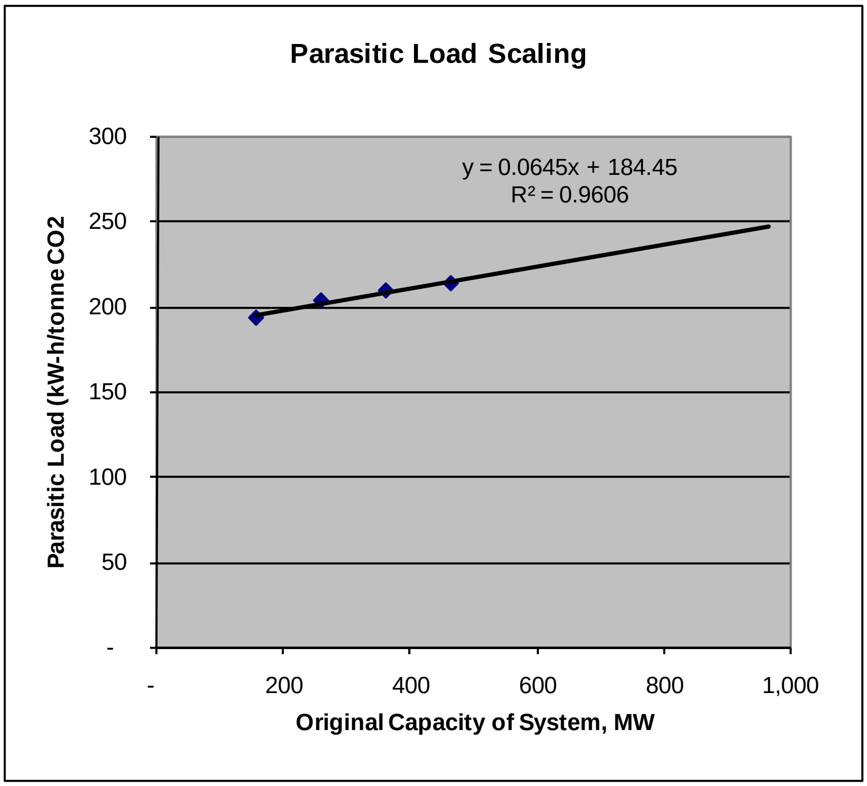


Figure 1-25. Parasitic Load Scaling for Carbon Capture Retrofit Components

The parasitic load factors associated with NOx, SO_2 and additional cooling were developed based upon the Baseline Report. A factor of 0.0001 kW parasitic load/kW capacity was used for NOx equipment and a value of 0.0091 kW parasitic load/kW capacity was used for SO_2 equipment. Additional cooling was determined to have a parasitic load of 0.033 kW parasitic load/kW capacity. A constant rate of 212.91 kWh/tonne CO_2 scrubbed was used for the parasitic steam rate for amine regeneration.

These five components are summed and reported as total parasitic load in units of kWh/tonne CO_2-captured. Make up power cost was calculated using the NETL projected 2020 electric generation cost.

1.3.9 Levelized Cost of Electricity

A levelized cost of electricity (LCOE) was calculated for each plant using methodology consistent with the Conesville Study. Figure 1-26 shows the LCOE equation from the Conesville Study. The equation levelizes the costs of capital, fixed and variable OM and feedstock over a levelization period and normalizes by the post-retrofit generation. The cost of make-up power associated with the retrofit parasitic load is calculated using the projected Waxman-Markey 2020 electric generation price. The CCM uses the same levelization period, capital charge factor, and levelization factors as the Conesville Study. For a 20-year levelization period, a capital charge factor of 0.175, a fixed and variable OM levelization factor of 1.1568, and a feedstock levelization factor or 1.1651 were used.

$$\mathbf{LCOE_P} = \frac{\mathbf{(CCF_P)(TPC) + [(LF_{F1})(OC_{F1}) + (LF_{F2})(OC_{F2}) + \ldots] + (CF)[(LF_{V1})(OC_{V1}) + (LF_{V2})(OC_{V2}) + \ldots]}}{\mathbf{(CF)(KWH)}}$$

Where:

LCOE =	levelized cost of electricity over P years
P =	levelization period (e.g., 10, 20, or 30 years)
CCF =	capital charge factor for a levelization period of P years
TIC =	total investment cost [the sum of bare erected costs (includes costs of process equipment, supporting facilities, direct and indirect labor), detailed design costs, construction/project management costs, project contingency, process contingency and technology fees]
LF_{Fn} =	levelization factor for category n fixed operating cost
OC_{Fn} =	category n fixed operating cost for the initial year of operation (but expressed in “first-year-of-construction” year dollars)
CF =	plant capacity factor
LF_{Vn} =	levelization factor for category n variable operating cost
OC_{Vn} =	category n variable operating cost at 100% capacity factor for the initial year of operation (but expressed in “first-year-of-construction” year dollars)
KWH =	annual net kilowatt-hours of power generated at 100% capacity factor

Figure 1-26. LCOE Equation and Parameters from Conesville Study

$$\textbf{CO}_\mathbf{2}\textbf{ Mitigation Cost} = (LCOE_{Cp} - LCOE_{Ref}) / (CO_{2Ref\ emitted} - CO_{2Cp\ emitted})$$

$$\textbf{CO}_\mathbf{2}\textbf{ Captured Cost} = (LCOE_{Cp} - LCOE_{Ref}) / (CO_{2Cp\ produced} - CO_{2Cp\ emitted})$$

<u>Where:</u>

CO_2 Mitigation Cost =	\$/ton of CO_2 avoided
CO_2 Captured Cost =	\$/ton of CO_2 removed
CO_2 =	Carbon dioxide (tons/kWh at plant capacity factor)
LCOE =	Levelized cost of electricity (\$/kWh)
$_{Cp}$ =	Capture plant
$_{Ref}$ =	Reference plant

Figure 1-27. Captured and Mitigated (Avoided) Carbon Costs

1.3.10 <u>Inclusion of Make-up Power</u>

The CCM also calculates carbon capture costs by tonne of captured carbon and tonne of avoided or mitigated carbon using the Conesville Study methodology. Figure 1-29 shows the captured and mitigated carbon cost equations from the Conesville Study.

The CO_2 capture cost is a measure of levelized cost of retrofit per tonne of CO_2 captured at the plant. Because the analysis assumes constant coal, the make-up power associated with the retrofit parasitic load must be generated by other plants. The CCM uses the NETL Waxman-Markey generation profile and average carbon loading values by generation type for the year 2020 to calculate the carbon loading associated with make-up power.

The emissions associated with this make-up power generation reduce the actual tonnes of carbon avoided to the atmosphere. The actual tonnes mitigated are equal to the tonnes captured minus the tonnes reintroduced through make-up power generation.

The LCOE equation, calculated for each generation unit, is adjusted as follows to account for make-up power.

$$LCOE_{MU} = (1\text{-}PL) * LCOE_{base} + PL * Cost_{MU}$$

Where:

$LCOE_{MU}$ - Levelized cost of electricity in the make up power case (\$/MWh)

$LCOE_{base}$ - Levelized cost of electricity in the base case (\$/MWh)

$Cost_{MU}$ - Cost of make-up power, \$/MWh (NEMS results for 2020 under Waxman Markey scenario)

PL - parasitic load, percent reduction in unit generating capacity going from no CO_2 capture to CO_2 capture

The cost of CO_2 capture is unaffected by the make-up power assumption, but the cost of CO_2 avoided is impacted by the make-up power.

$$CO_{2cp,\,MU} = (1\text{-}PL) * CO_{2cp,\,base} + PL * CO_{2MU}$$

Where:

CO_2 - Carbon dioxide emissions, metric tons CO_2 / kWh

PL - parasitic load, percent reduction in unit generating capacity going from no CO_2 capture to CO_2 capture

$_{cp}$ Capture Plant

$_{MU}$ Make up

2. RESULTS

This section provides the analytical results of the analysis. It should be noted that all costs presented relative to carbon capture do not consider base plant costs and represent only costs associated with the retrofit. An Appendix presents a catalog of the plants analyzed, including site-specific imagery for carbon capture retrofits for individual plants in the viable population.

2.1 CAPEX RESULTS

CAPEX, OPEX, and parasitic costs were calculated for the population of viable plants for three scenarios with varied capacity factors of 65, 75, and 85 percent respectively. Results were calculated for two cases: (1) a carbon capture case, which does not consider carbon allowance nor the cost and carbon emissions associated make-up power, and (2) a carbon mitigation case, which models the effects of Waxman-Markey assumptions for make-up power costs and carbon emissions.

Figure 2-1. Nameplate Capacity as a Function of CO_2 Capture CAPEX by Unit shows CO_2 capture CAPEX as a function of nameplate capacity for the 738 individual analyzed units. Note that large units demonstrate relatively low CAPEX rates (green oval), while smaller plants demonstrate high CAPEX variability (red oval).

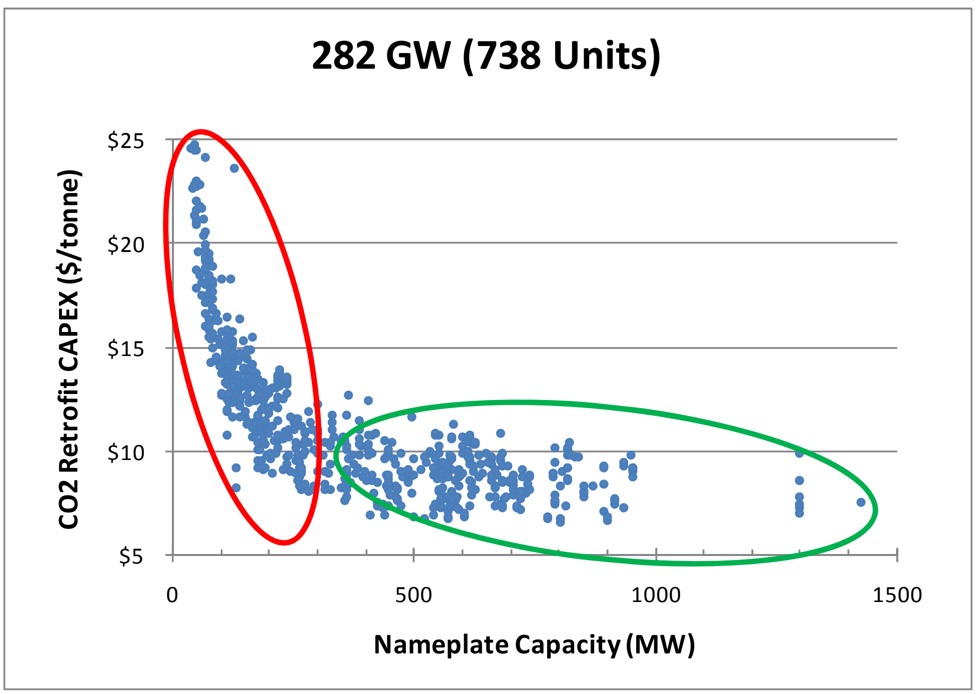


Figure 2-1. Nameplate Capacity as a Function of CO_2 Capture CAPEX by Unit

2.2 BASE CASE (NO MAKE-UP POWER)

This case determines the base LCOE and carbon capture costs. The LCOE was calculated without inclusion of make-up power. Levelized carbon capture costs were calculated without consideration of carbon emitted through generation of make-up power, and essentially represent CAPEX and OPEX costs associated with physically capturing carbon from the flue gases.

In Figure 2-2. Base Case, Cumulative U.S. Coal Generating Capacity versus Incremental LCOE for CO_2 Capture Retrofit, all the generating units are ranked from least to highest incremental cost of power required to "cover" the cost of CO_2 capture. Figure 2-3 is a similar graphic that presents the cost of CO_2 captured versus cumulative generating capacity.

Figure 2-2 is interpreted as follows. Reading off the 75% capacity factor line, the Conesville generating plant has a cost of incremental cost of electricity of CO_2 capture of $54/MWh which places it at the 20% percentile. That is, 20% of the coal fired generating capacity has an incremental cost of electricity less than $54/mt CO_2. The other 70% of coal-fired capacity has a higher cost. Figure 2-2 shows that increasing the assumed capacity factor from 75% to 85% lowers the incremental cost of electricity by roughly $6/MWh. Lowering the assumed capacity factor to 65% increases the incremental COE by roughly $8/MWh.

Figure 2-3 shows that roughly 70% of the generating capacity has an incremental cost of power of $70/MWh or less. After that the curve flattens out and the costs begin increasing more rapidly. By comparison the CO_2 capture cost curves in Figure 2-3 are steeper. The explanation for this is partially seen in Figure 2-1 which shows a wide variation in CAPEX, the primary determinant of LCOE. The CO_2 capture cost, however, is driven strongly by a unit's efficiency which has a much lower variation across the fleet.

A range of capacity factors was modeled (values of 65, 75, and 85 percent).

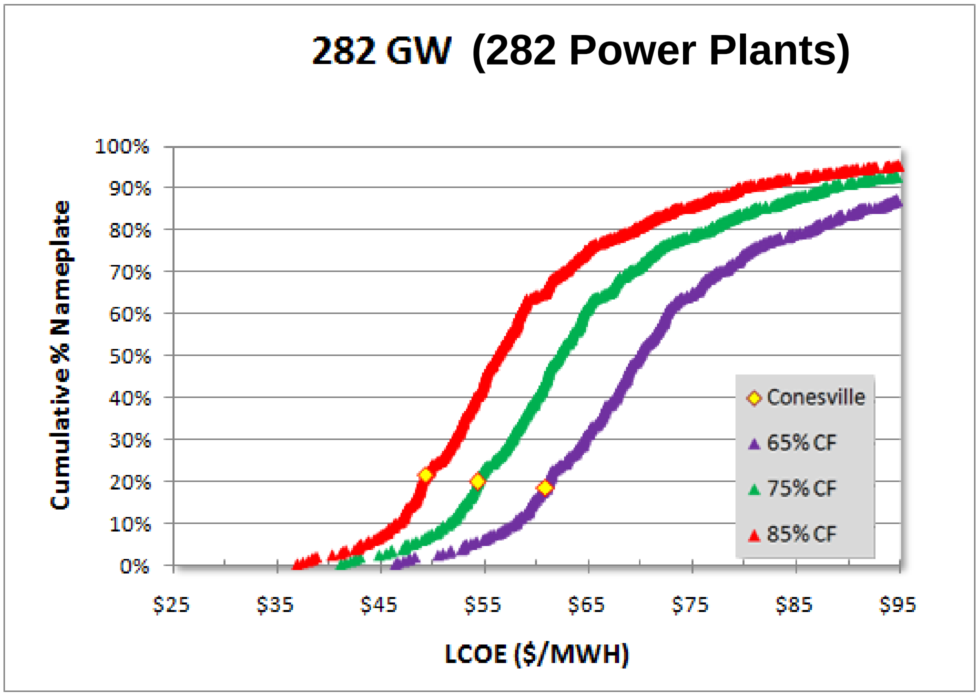


Figure 2-2. Base Case, Cumulative U.S. Coal Generating Capacity versus Incremental LCOE for CO_2 Capture Retrofit

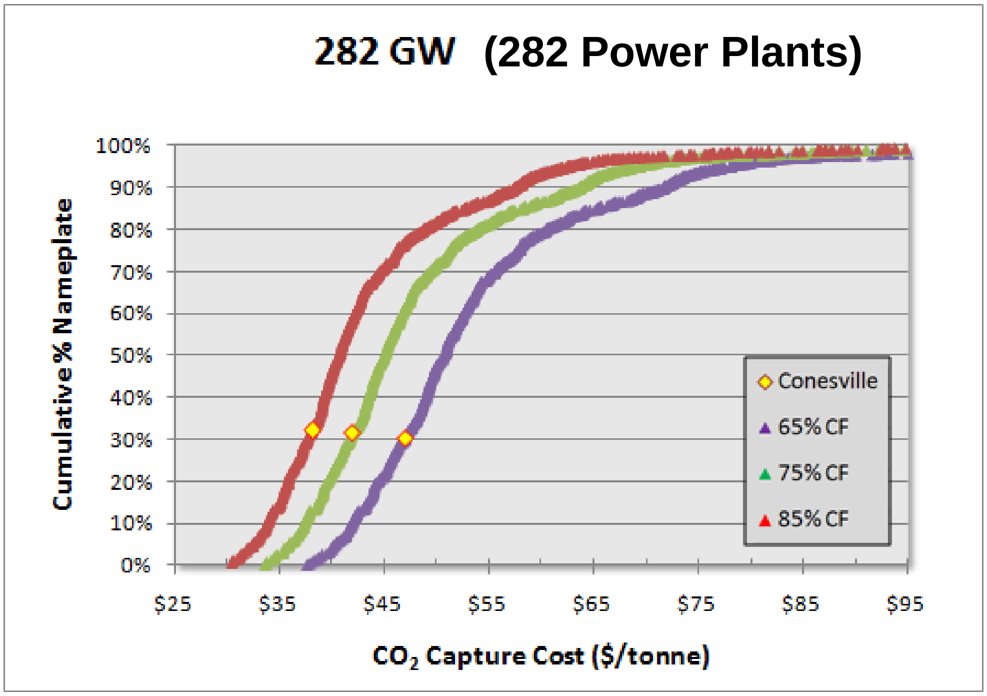


Figure 2-3. Base Case, Cumulative U.S. Coal Generating Capacity versus Retrofit CO_2 Capture Cost

2.3 MAKE-UP POWER CASE

A coal-fired generating unit with CO_2 capture using amine based scrubbing will lose roughly 30% of its generating capacity. An alternative analysis methodology will consider the cost and GHG emissions of make-up power. That is, the owning entity buys power – either via a contract or on the spot market, to "make-up" for the generation that is being consumed by the parasitic load of the CO_2 capture plant.

This case determines LCOE and carbon mitigation costs assuming NETL's Waxman-Markey (W-M) projections. LCOE was calculated including make-up power costs based on the cost of electricity in each unit's EMM region. Levelized carbon mitigation costs were calculated with consideration of carbon emitted through generation of make-up power, and represents estimated costs associated with avoiding carbon emissions to the atmosphere.

Figure 2-4 shows the incremental cost of electricity versus cumulative generating capacity for the make-up power case. The current cost of commodity power was not applied to the make-up power calculation, rather the forecasted cost under a GHG mitigation scenario. Specifically, the power costs contained in NEMS outputs for 2020 under a Markey Waxman scenario was used.

At the median cost, the curve in Figure 2-5 represents a horizontal shift of roughly $43/MWh compared to Figure 2-4. The slope of Figure 2-5 is shallower. The horizontal shift is higher for the high-cost generating units due to the spiraling effect of lower base plant efficiency. The shift is lower at the low cost region for the same reason.

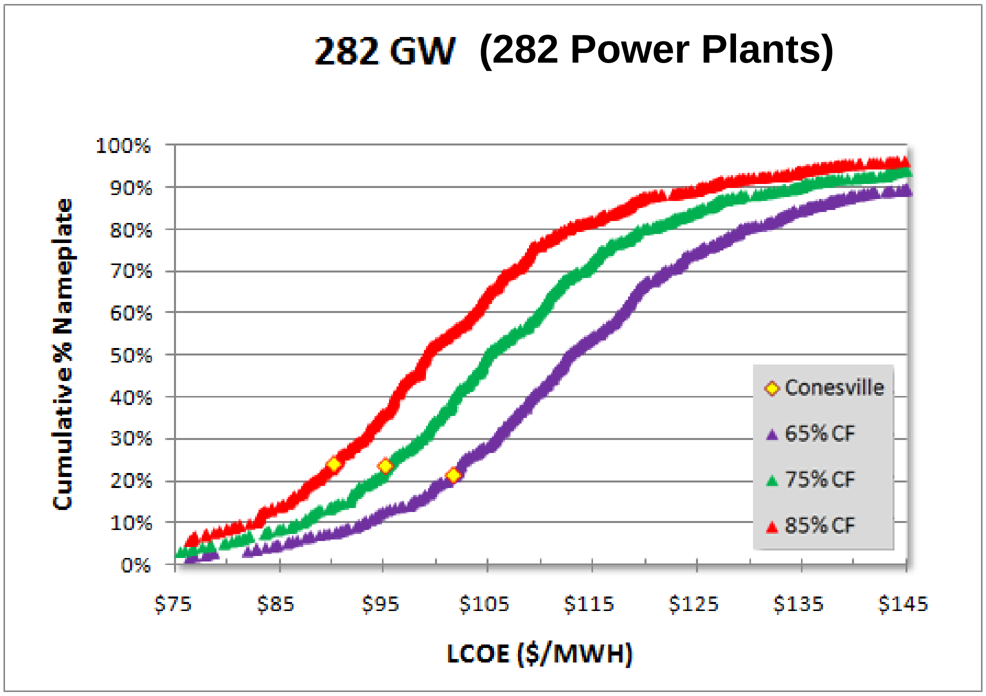


Figure 2-4. Make-up Power Case, Cumulative U.S. Coal Generating Capacity versus Incremental LCOE for CO_2 Capture Retrofit

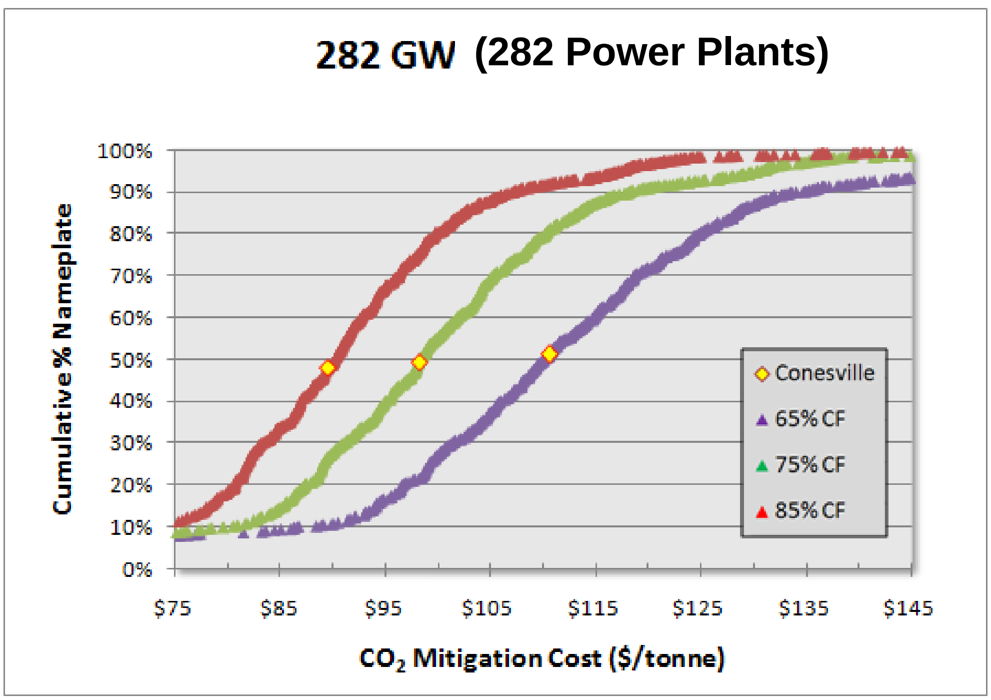


Figure 2-5. Make-up Power Case, Cumulative U.S. Coal Generating Capacity versus Retrofit CO_2 Capture Cost

2.4 COMPARISON WITH CONESVILLE STUDY RESULTS

The results for incremental COE, capture cost, and mitigation cost for the Conesville generating unit are different in this study than in the source study developed by NELT and AEP, Table 2-1. Table 2-2-2 shows that the difference is explained by a higher CAPEX and OPEX, both due to the inclusion of additional cooling, emissions controls and auxiliary load requirements. The current study also assumes a higher price and regionally-based carbon emissions for make-up power, which contributes to the difference.

Table 2-1. Results from the Conesville Study and CCM

Conesville Unit 5	Nameplate	LCOE	Capture Cost	Mitigation Cost
	(MW)	($/MWh)	($/tonne)	($/tonne)
Conesville Study	465.5	$ 69	$ 59	$ 89
CCM	463.5	$ 49	$ 38	$ 90
Delta	0.4%	29%	36%	-1%

Table 2-2. Key Input Parameters from the Conesville Study and CCM

Conesville Unit 5	Nameplate	Total Aux Load	CO2 CAPEX	Electricity Price	Make-up Power Cost
	(MW)	(MW)	(10^6 $)	($/MWh)	(10^6 $)
Conesville Study	465.5	130.5	$ 400	$ 0.064	$ 21.2
CCM	463.5	148.9	$ 456	$ 0.076	$ 27.3
Delta	0.4%	-14%	-14%	-19%	-29%

3. CONTINUING WORK

NETL has conducted a stakeholder review of the first version of this version of the PC retrofit report and is working to refine and enhance the analysis. The following are priority objectives to be contained in a revised document, set to be posted in the Spring of 2011.

- Provide capability for the model to assess advanced retrofit technologies which reduce the costs and energy penalties for CO_2 capture
- Examine the potential synergy of refurbishing units with efficiency (heat rate) upgrades in conjunction with CO_2 capture retrofits
- Provide additional hard cost and performance data points by integrating results from current engineering-level retrofit studies currently in progress
- Improve and refine data quality and calculations in the following manner:
    - Refine the viable population criteria to operate on unit rather than plant totals and averages
    - Incorporate base plant costs in the LCOE calculations
    - Perform a full twenty-year cost levelization using discrete electricity prices and generation profiles by EMM by year using NETL's projections
    - Collect and integrate data on the timing of the installation of NO_x and FGD equipment relative to efficiency drops
- Further characterize viable sequestration opportunities by type and capacity
- Incorporate costs for CO_2 transportation and storage into output metrics

APPENDIX A. EV Suite Data Elements

The data tables can be located in the EV.mdb Access database.

Units Table

Data Item: Plant Name

SOURCE: EIA 860, EIA 906, NERC 411, StatsCanada, CFE, Global Energy Primary Research

DESCRIPTION: The most commonly used name for a power plant. A facility containing prime movers, electric generators, and auxiliary equipment for converting mechanical, chemical, and/or fission energy into electric energy.

Data Item: Plant ID

SOURCE: Global Energy

DESCRIPTION: Unique Global Energy entity id corresponding to the plant name.

Data Item: Unit

DESCRIPTION: Any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electric power.

Data Item: Unit ID

SOURCE: Global Energy

DESCRIPTION: Global Energy entity id for the unit.

Data Item: Unit Status

SOURCE: Global Energy Primary Research

DESCRIPTION: The current status of the generating unit

Operating Categories:

OP	Operating	Generator available to operate
SB	Standby	Generator available for service but not normally used, or on short term scheduled or forced outage for less than 3 months
OS	Out of Service	Generator on long term scheduled or forced outage for more than 3 months
RT	Retirement	Generator planned for retirement
RS	Restart	Generator brought back online after being Retired or Mothballed for more than 5 years
SO	Steam Only	Generator was removed from electric generation service and continues to operate solely as steam generator

Planned Categories:

FE	Feasibility	Planned new generator undergoing feasibility study
PL	Proposed	New generator planned for installation
AP	App Pending	Application(s) filed for permit(s), regulatory approval pending
PM	Permitted	Two or more permits approved or contracts for fuel or power have been received
SP	Site Prep	The power plant site is being prepared for construction
UC	Under Const	Planned generator under construction
TS	Testing	Generator operating under test conditions, not in commercial service

Canceled Categories:

CN	Canceled	Planned new generator canceled
PP	Postponed	Planned new generator indefinitely postponed

Cold Standby Category:

SC	Cold Standby	Generator in deactivated status requiring more than 6 months to reactivate

Mothballed Category:

MB	Mothballed	Generator taken out of service but not retired, unit is able to come back online in future

Retired Categories:

RE	Retired	Generator no longer in service and not expected to be returned to service
CV	Converted	Generator was converted (refurbished) from stand-alone status to combined-cycle configuration

Data Item: Nameplate Capacity MW

DESCRIPTION: The maximum rated output of a generator, prime mover, or other electric power production equipment under specific conditions designated by the manufacturer. Installed generator nameplate capacity is commonly expressed in megawatts (MW) and is usually indicated on a nameplate physically attached to the generator.

INSTRUCTIONS: For EIA 860, 906 and NERC ES&D: For line 1, Maximum Generator Nameplate Capacity, report the highest value on the nameplate in megawatts rounded to the nearest tenth.

Data Item: EV Fully Loaded Tested Heat Rate Btu/kWh

SOURCE: Global Energy Intelligence

DESCRIPTION: Energy Velocity has created a process to obtain the best fully loaded tested heat rate for a unit based on several different sources. These sources are detailed in the help for the EV Fully Loaded Tested Heat Rate Source field.

At the onset of this project, Global Energy analysts used various resources to determine a low and high point for heat rates by Generator Availability Data System (GADS) category. By looking at heat rate data by GADS category a default heat rate was also determined.

The process takes each thermal unit in the database and then moves down the list of sources looking to see if that unit has data for that source. If there are data for that unit for the first source (EV Research) and the data reported fall within the range determined for the GADS category of the unit, that heat rate would then be the value used for that unit in the EV Heat Rate item. If there is no EV Research data for that unit, the process will then look at the CEMS data to see if there is data for that unit. Again if there are data and the heat rate calculation is within the range that heat rate would be the value used for that unit in the EV Heat Rate item. The process follows down the list of sources and if there are no data to support a heat rate within the range at any of the sources, a default value will be used for the EV Heat Rate item.

As new data are received or new information is found for a unit the EV Fully Loaded Tested Heat Rate value can change for that unit.

Data Item: Prime Mover

SOURCE: EIA 860, 906, NERC ES&D, CFE, StatsCan and Global Energy Primary Research

DESCRIPTION: The engine, turbine, water wheel, or similar machine that drives an electric generator or a device that converts energy to electricity directly (photovoltaic solar and fuel cells).

Data Item: Supercritical (Y/N)

SOURCE: Global Energy Research

DESCRIPTION: The terms supercritical and ultra-supercritical are derived from the definition of the temperature and pressure at which water vapor and liquid water are indistinguishable - known as the Critical Point. The Critical Point of water occurs at 705 degrees Fahrenheit under pressure of 3208 pounds per square inch (psia). At the Critical Point, the bubbling formation associated with boiling no longer occurs. Instead, with the addition of heat or increase in pressure the fluid experiences a continuous transition from water-like to steam-like characteristics.

Pressure is said to be "supercritical" when the pressure exceeds 3208 psia. A conventional supercritical unit operates at a steam pressure of 3500 psi or higher and steam temperatures of 1000 - 1050F. By contrast, a subcritical unit operates below the critical pressure, typically 2400 psi at similar temperatures.

By operating at elevated steam pressures and temperatures, the turbine cycle is more efficient. This reduces fuel consumption, and reduces emissions in the process.

Data Item: SO_2 Control Equipment (Y/N)

SOURCE: U.S. EPA Clean Air Markets Division facility attributes and Global Energy Research

DESCRIPTION: Indicates whether unit is known to have one or more SO2 control technologies in place

Data Item: NOx Control Equipment (Y/N)

SOURCE: U.S. EPA Clean Air Markets Division facility attributes and Global Energy Research

DESCRIPTION: Indicates whether unit is known to have one or more NOx control technologies in place

Data Item: SO_2 Annual Rate lbs/mmBtu

SOURCE: US EPA CEMS

DESCRIPTION: SO_2 emissions rate in lbs/mmBtu for the most recent complete calendar year of data available from the U.S. EPA CEMS database. (The EPA releases 4th quarter data in February of the following year.)

hen aggregated this item will provide a weighted average value, weighted by Nameplate Capacity.

IMPORTANT NOTE: Only units that report SO_2 emissions will be included in this average.

Data Item: NOX Summer Rate lbs/mmBtu

SOURCE: US EPA CEMS

DESCRIPTION: NOx emissions rate in lbs/mmBtu for the NOx season (May through September) of the most recent complete calendar year of data available from the U.S. EPA CEMS database. (The EPA releases 4th quarter data in February of the following year.)

When aggregated, this item will provide a weighted average value, weighted by Nameplate Capacity.

IMPORTANT NOTE: Only units that report NOx emissions will be included in this average.

Data Item: CO_2 Annual Rate lbs/mmBtu

SOURCE: EPA

DESCRIPTION: CO_2 emissions rate in lbs/mmBtu for the most recent complete calendar year of data available from the U.S. EPA CEMS database. (The EPA releases 4th quarter data in February of the following year.)

When aggregated, this item will provide a weighted average value, weighted by Nameplate Capacity.

IMPORTANT NOTE: Only units that report CO_2 emissions will be included in this average.

Plant Generation and Production Table

Data Item: Total mmBtus

SOURCE: EIA 906, Ontario IESO, CEMS

DESCRIPTION: Total consumption of the fuel specified, in millions of Btus.

Note: this is the total quantity consumed for both electricity and, in the case of combined heat and power plants, process steam production.

Data Item: Net Generation MWh

SOURCE: EIA 906, Ontario IESO, CEMS

DESCRIPTION: This is the monthly net generation as reported (in MWh) on the EIA 906 or Independent Electricity System Operator (Ontario) generator disclosure report. Combined heat and power facilities report gross generation for each prime mover whereas electric power plants report net generation.

INSTRUCTIONS: EIA 906: Generation: column g.

Report a single net generation value for all prime movers of a single type, regardless of the number of energy sources for that prime mover. For example, all generation from your steam turbines with multiple energy sources should be reported as one number under the primary energy source.

All Plants Other Than Pumped Storage and Compressed Air Storage: When station use electrical demand exceeds the gross electrical output of the plant, a negative number should be reported for net generation. Indicate negative amounts by using a minus sign before the number.

Hydro Pumped Storage and Compressed Air Energy Storage Plants: Report gross generation in column (f) and net generation (gross generation minus station use) in column (g). Report pumping energy in column (h) (energy source consumption).

Note that during months when the storage facility is returning power to the grid, none of these values will typically be negative. If you need assistance with these new instructions for storage facilities, contact the survey manager.

Data must be reported in megawatthours (MWh), rounded to whole numbers, no decimals.

Enter zero when a plant has no generation for a prime mover.

Combined Cycle Units: Report generation for the combustion turbine (CT) and the steam turbine (CA) separately. If multiple energy sources are used, report each energy source separately. Report supplemental firing fuels in duct burners and/or auxiliary boilers under steam turbine code (CA).

CEMS (Continuous Emissions Monitoring System) Table

Data Item: Sum Total CO_2 Emissions tons (by ownership %)

SOURCE: EPA

DESCRIPTION: Total CO_2 emissions for the year in tons. Emissions are broken out by ownership percentage of the unit. This query uses the current ownership of the units and does not reflect prior changes in ownership. When aggregated, this item will provide a sum value.

Reported in Short Tons (i.e. US Tons).

Data Item: Sum Total SO_2 Emissions tons (by ownership %)

SOURCE: EPA

DESCRIPTION: Total SO2 emissions for the year in tons. Emissions are broken out by ownership percentage of the unit. This query uses the current ownership of the units and does not reflect prior changes in ownership. When aggregated, this item will provide a sum value.

Data Item: Sum Total NOx Emissions tons (by ownership %)

SOURCE: EPA

DESCRIPTION: Total NOx emissions for the year in tons. Emissions are broken out by ownership percentage of the unit. This query uses the current ownership of the units and does not reflect prior changes in ownership. When aggregated, this item will provide a sum value.

Data Item: Wtd Avg CO_2 Emissions Rate lbs/MWh

SOURCE: EPA, Global Energy Primary Research

DESCRIPTION: Average CO_2 emissions rate for the year in lbs/MWh.

When aggregated, this item will provide a weighted average value, weighted by Net Generation.

IMPORTANT NOTE: Only units that report CO_2 emissions will be included in the average.

Data Item: Wtd Avg SO2 Emissions Rate lbs/MWh

SOURCE: EPA, Global Energy Primary Research

DESCRIPTION: Average SO2 emissions rate for the year in lbs/MWh.

When aggregated, this item will provide a weighted average value, weighted by Net Generation.

IMPORTANT NOTE: Only units that report SO2 emissions will be included in the average.

Data Item: Wtd Avg NOx Emissions Rate lbs/MWh

SOURCE: EPA, Global Energy Primary Research

DESCRIPTION: Average NOx emissions rate for the year in lbs/MWh.

When aggregated, this item will provide a weighted average value, weighted by Net Generation.

IMPORTANT NOTE: Only units that report NOX emissions will be included in the average.

Plant Coal Transactions Table

Data Item: Fuel Code Abbrev

SOURCE: Global Energy Primary Research

DESCRIPTION:

FUELCODE	DESCRIPTION
ANT	Anthracite Coal
BC	Beneficiated Coal
BIT	Bituminous Coal
COK	Coker bi-product
COL	Coal
PC	Petroleum Coke
SC	Coal Based Synfuel
SUB	Subbituminous Coal
WC	Waste Coal

Data Item: Quantity (000s tons)

SOURCE: FERC 423 EIA 423

DESCRIPTION: Quantity of fuel delivered during the report month.

INSTRUCTIONS: Enter quantities in thousands of tons for coal, thousands of barrels for oil and other liquid fuels, and thousands of mmBtu (billions of British Thermal Units) for gas. For example, if 213,000 tons of coal are delivered during the reporting month,

Report 213. Enter separate quantities for each type of fuel. To derive the quantity, group all fuels received within the month from the supplier for which the price was based upon a given or related set of laboratory analyses. Note: For quantities of fuel received from a given supplier during the month for which no laboratory analysis is made, report on the basis of the last previous laboratory analysis upon which price paid was determined for that supplier or on the basis of contract specifications or estimates, and specify in a footnote the basis used.

Data Item: Sulfur %

SOURCE: FERC 423 EIA 423

DESCRIPTION: Sulfur content of fuel (except gas) in terms of percent sulfur by weight on an "as received" basis.

INSTRUCTIONS: For all fuels except gas, enter sulfur content of fuel in terms of percent sulfur by weight. Show to the nearest 0.01%.

Land Table

Data Item: Land & Land Rights $

SOURCE: FERC Form 1, EIA 412, RUS 12

DESCRIPTION: This is the $ expense for land and land rights for this plant.