OCS Study BOEM 2012-100

Analysis of the Costs and Benefits of CO_2 Sequestration on the U.S. Outer Continental Shelf

ICF INTERNATIONAL

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Acronyms

AEO	Annual Energy Oulook (U.S. Energy Information Administration)
AoR	Area of Review Under EPA's UIC Program including for CO_2 GS injection wells
BEG	Bureau of Economic Geology the University of Texas
BOEM	Bureau of Ocean Energy Management
CAA	Clean Air Act
CCS	Carbon Capture and Storage
CERCLA	Comprehensive Environmental Response Compensation, and Liability Act
CES	Clean Energy Standard
CO_2 EOR	Enhanced Oil Recovery through injection of CO_2
DOE	U.S. Department of Energy
DOE NETL	Department of Energy's National Energy Technology Laboratory
DOI	U.S. Department of the Interior
ECBM	Enhanced coalbed methane recovery
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
GHG	Greenhouse Gas
GS	Geologic Storage of carbon dioxide
GT	Gigatonnes
GW	Gigawatts
IGCC	Integrated Gasification- Combined Cycle power plant
IPCC	Intergovernmental Panel on Climate Change
IPM	ICF's Integrated Planning Model
MEA	Mono-ethanol amine
MIT	Mechanical Integrity Test
MRV	Monitoring, Reporting, and Verification for CO_2 injection
MW	Megawatts
MWh	Megawatt-hours
NATCARB	U.S. Department of Energy National Carbon Atlas
NEMS	EIA's National Energy Modeling System
NEPA	National Environmental Policy Act
NGCC	Natural Gas Combined Cycle power plant
OCS	Outer Continental Shelf
PC	Pulverized Coal power plant
PISC	Post-Injection Site Care
RCRA	Resource Conservation and Recovery Act
RGGI	Regional Greenhouse Gas Initiative
RPS	Renewable Portfolio Standard
SDWA	Safe Drinking Water Act
SOx and NOx	Oxides of Sulfur and Nitrogen
UCG	Underground Coal Gasification
UIC	EPA Underground Injection Control program
UIC Class VI well	EPA designation for permitting a CO_2 GS injection well
USDWs	Underground Sources of Drinking Water
VEF	EPA's Vulnerability Evaluation Framework
WCI	Western Climate Initiative
WGA	Western Governors' Association

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1. Executive Summary

1.1 Introduction and Objectives

Currently, the U.S. does not have a national greenhouse gas policy to encourage carbon dioxide (CO_2) capture and geologic storage. Such a policy could take the form of a "cap and trade" system, in which future greenhouse gas caps are specified and an emission credit trading system is established that effectively puts a cost on CO_2 emissions. The policy might also take the form of a tax or fee on carbon emission or a set of performance standards for carbon-emitting technologies and processes. Under one or a combination of such systems, it is expected that geologic sequestration of CO_2 will occur as one of several carbon mitigation strategies.

The U.S. generates almost six billion metric tons (gigatonnes) of anthropogenic CO_2 emissions annually. As a part of a greenhouse gas reduction strategy, future CO_2 emissions from some stationary sources could be captured and transported through pipelines to CO_2 geologic sequestration (GS) sites for long-term sequestration thousands of feet below the surface. While much of this possible sequestration activity is expected to occur in onshore areas, a significant amount of injection could occur offshore. It is, therefore, important to understand the potential location, scope, economics, and costs and benefits of offshore geologic sequestration.

The Energy Policy Act of 2005 gives the Secretary of the Interior and BOEM the authority to grant property rights and to collect revenues for activities on the Outer Continental Shelf (OCS) that support the production of energy from sources of energy other than oil and gas. BOEM is considering implementing this authority by issuing regulations for granting leases on the OCS for the purpose of GS.

To prepare for potential sequestration regulations, BOEM requires an analysis of the net economic benefits that could be realized if access to OCS sites is allowed for CO_2 sequestration. The analysis involves evaluating the potential economic viability of offshore storage, the potential benefits to society of offshore GS, and an understanding of various trade-offs, such as environmental impacts and potential incompatibilities with oil and gas development.

Such an analysis would also provide a context for other activities on the OCS that may be proposed in the future to support the development of energy from non-oil and gas sources, including wind energy. To assist BOEM with these objectives, ICF has carried out the current study to evaluate the potential for U.S. offshore CO_2 sequestration and its costs and benefits. A summary of this study could serve as a preamble to a possible federal rulemaking on this issue. The detailed results of the study are described in this report.

1.2 Potential Advantages of Offshore Sequestration

While a great deal of attention has been directed toward onshore geologic sequestration, there are several potential advantages to offshore sequestration.[1]

- Offshore storage provides additional storage potential to supplement onshore geologic sequestration (GS) capacity.
- The Gulf of Mexico in particular provides the U.S. with a very good geologic basin for offshore Carbon Capture and Storage (CCS) in terms of saline reservoir capacity, Enhanced Oil Recovery (EOR)-related storage capacity, and shallow water.
- Offshore storage capacity is often in the vicinity of many heavily populated coastal areas.
- There are few underground sources of drinking water offshore (as compared to onshore basins that typically contain potable groundwater near the surface). Offshore formation fluid is typically similar to seawater in salinity
- Construction of offshore pipelines should be feasible, given oil and gas infrastructure in parts of the OCS.
- A single entity (DOI) would be primarily responsible for leasing, permitting and regulation on the OCS.
- Pore space rights would not be dispersed among potentially hundreds of owners as is often the case onshore.
- To the extent that offshore storage may be easier to site, permit, finance and operate, it may be faster and more economical to develop compared to some onshore storage

1.3 Approach to Study

Much of the analytical work in this study was carried out with ICF's IPM® model, which was used to generate model forecasts through 2050 for cases with and without offshore GS. The model results have been used to quantify the net economic benefits to society over the forecast period. The assumptions and results of the model runs are presented in the last two report sections.

[1] Some these points are made in a Department of Energy paper presented at the 2011 Offshore Technology Conference titled "Carbon Capture and Storage: The U.S. Department of Energy's R&D Efforts to Characterize Opportunities for Deep Geologic Storage of Carbon Dioxide in Offshore Reservoirs," OTC paper 21987, May 2011, and in Environmental Defense Fund, 2011, "Policy Recommendations for Selection and Development of Offshore Geologic Carbon Sequestration Projects within Texas State Waters," December 2, 2011, http://www.edf.org.

The net benefits to the U.S. economy are estimated using the classical economic definition that net benefits (costs) are the sum of all positive and negative changes in consumers' and producers' surpluses. These net changes are estimated by comparing a No-OCS Case and OCS Case. The No-OCS Case assumes that no GS of carbon dioxide is allowed on the OCS while the OCS Case assumes GS on OCS is allowed. In both cases it is assumed that some form of a national carbon policy is begun in 2015 with an effective price on carbon set to $54 per short ton in 2030 and $152 per short ton in 2050 (real 2010 dollars). Other assumptions are taken largely from the Energy Information Administration 2011 Annual Energy Outlook (AEO). Most assumptions come from the AEO Reference Case, but assumptions for carbon prices and electricity growth rates are from EIA's Economywide GHG Policy Case. The economic impacts of a policy to allow GS on the OCS are estimated by comparing the results of the two cases.

ICF has modeled the distribution and characteristics of a future U.S. CO_2 pipeline system. Pipeline corridors link sources of CO_2 such as coal power plants with potential geologic sequestration sites. This information was incorporated into the IPM® model, and the model develops the pipeline system through the forecast.

The ICF GeoCAT model was used to evaluate the economics of different storage options for both onshore and offshore areas. Economic analysis includes costs for site characterization, drilling and completing injection and monitoring wells, and monitoring costs during and after injection. Geologic storage options include saline reservoirs, depleted oil and gas reservoirs, and CO_2 enhanced oil recovery. Sequestration cost curves from GeoCAT were incorporated into the IPM® model.

IPM® is a multi-regional, dynamic, linear programming model of the North American electric power sector including all major generators. It includes a comprehensive capability for coal, natural gas, and biomass supply and demand. It uses a production costing model to determine the least cost solution to meeting electric generation energy and capacity requirements, subject to environmental, transmission, fuel, reserve margin, and other system operating constraints. The volume of GS that is forecast in the model is a function of assumed CO_2 allowance prices, the economics of GS in both onshore and offshore settings, and the economics of other (non-GS) options to reduce CO_2 emissions, such as fuel switching.

1.4 Conclusions

Net Benefits

- Based upon the assumptions used here, the addition of geologic storage (GS) on the OCS has an undiscounted cumulative net benefit to the U.S. economy of $16.9 billion between 2015 and 2050. Less than 2 percent of this benefit occurs before 2030. The size and timing of this benefit depends on many uncertain forecast assumptions such as the timing and severity of future GHG regulations, the degree to which CCS is subsidized, growth in electricity demand, the price of natural gas, the cost and practicality of building new nuclear power plants, and the cost and practicality of onshore geologic storage of carbon dioxide.

Geologic Sequestration Potential

- Offshore Lower-48 potential is approximately 3,600 billion metric tonnes (gigatonnes) out of 11,100 gigatonnes. Most of the assessed storage potential is in the Gulf of Mexico, where a variety of factors are very favorable for storage including suitable reservoirs at reasonable depth with good permeability, shallow waters, and existing infrastructure

- The greatest volume of offshore sequestration potential by far is in saline reservoirs, which are abundant and accessible, with large volumes assessed in the Gulf of Mexico. There is also significant saline potential in the Atlantic and Pacific OCS.

- CO_2 EOR potential is by far the lowest cost option for GS. It has a “negative” storage cost, meaning that the value of the oil recovered more than offsets the cost of storing the CO_2. CO_2 EOR capacity is present in the Gulf of Mexico and to some extent in the Pacific, but is small relative to saline reservoirs. Onshore EOR capacity is much greater than offshore EOR capacity. Thus, forecast activity is concentrated in onshore EOR reservoirs first, and then moves to offshore EOR.

- Current assessments of the Atlantic and Pacific OCS are relatively low, but this is at least in part likely due to less available data and relatively minimal assessment efforts to date. Most of this is saline capacity, which is more costly than EOR capacity. Although these areas may not be as favorable as the Gulf of Mexico in some respects, they may eventually be accessed for GS due to proximity to population and industrial centers, paucity of onshore storage options, and other factors.

Economic Analysis of Geologic Sequestration in the U.S.

- Economic analysis of GS includes the costs of site characterization, drilling of the injection well, operating costs, and monitoring costs. This analysis is carried out by state and type of reservoir. Offshore cost factors and assumptions were used to determine offshore storage economics. The analysis results in a "supply curve" that relates available storage capacity to cost.

- In the current study, the economic availability of GS is evaluated in terms of the potential annual injection rate for a given volume of capacity. For example, for an assessed capacity in an area of 1,000 megatonnes, the potential annual injection rate over a 50 year period is assumed to be 20 megatonnes. This method is used to relate the economics of GS by state and reservoir type to the modeling framework.

- The Lower-48 has 109 gigatonnes per year of storage capacity economic below $10 per metric ton, including the OCS (excluding pipeline costs). This equates to about 5,450 gigatonnes of storage capacity (109 times 50 years).

- At $5 or less per metric ton, the annual storage capacity is 47 gigatonnes, which is mostly onshore.

- This 47 gigatonnes compares to annual U.S. emissions of carbon dioxide from stationary sources of a roughly 3.8 gigatonnes per year. Therefore, based on the assessed GS capacity and costs, there would be little need for future GS storage capacity through 2050 costing more than $5 per tonne.

- Since most of the OCS potential is more than $5 per tonne, there would not be a great deal of OCS storage, based purely upon economics and the assumptions used here.

- The OCS has some EOR potential (about 1.13 gigatonnes or 22.5 megatonnes per year), and the cost of that potential is below $5 per tonne. However, there are no assessed, non-EOR GS opportunities in the OCS with costs below $5 per tonne. Because there is so much more onshore EOR storage as modeled, the great majority of the projected economic storage activity is onshore.

Selected Modeling Assumptions for ICF IPM Model

- The U.S. EPA's IPM® v4.10 Base Case was used as the starting point for the modeling, along with updates from selected assumptions from Energy Information Administration's Annual Energy Output. The BOEM cases however, have the addition of a national CO_2 policy to incentivize CCS.

- The crude oil price projection is based upon AEO and increases from $79 per barrel in 2010 to $121 in 2035 in 2010 dollars.

- CO_2 allowance prices in 2010 dollars increase from $25 per ton in 2015 to $152 per ton in 2050.

Modeling Results

- Because there is much onshore EOR storage available as modeled, the great majority of the projected storage activity is onshore.

- This delays the economic benefit of opening up the OCS. <u>However, should assumptions used in this study about the availability and cost of onshore GS not be correct, offshore GS would be developed at an early stage and the net present value benefit of opening the OCS would be much greater.</u>

- For example, should siting or permitting problems greatly restrict onshore GS, this could favor offshore GS. Such a scenario is not modeled here.

- In the model runs, capture and sequestration begins in approximately 2015 when the carbon policy begins to put a price on carbon emissions. Total CO_2 captured increases from 15 million tons per year in 2015 to 664 million tons per year by 2050.

- In the initial forecast years, GS storage takes place only at onshore EOR sites. Shortly thereafter, it also moves to offshore EOR sites. Storage predominately in EOR sites in the U.S. continues until 2040, when storage in saline aquifers becomes the marginal, price setting type of GS site.

- In the forecast, GS on the OCS starts in 2025. The only projected geologic storage on the OCS is for EOR in the portion of Gulf of Mexico adjacent to Louisiana. The lack of EOR potential in the Pacific and Atlantic precludes sequestration in those areas as currently modeled for the reasons presented above. The stored CO_2 is captured from plants in the “Florida” model region and the “Southern” (central Gulf Coast) model region.

- By 2050 in the OCS GS case, about 23 million metric tons per year are stored in the OCS (all in the Gulf of Mexico) out of a total volume of U.S. CO_2 stored of 665 million metric tons.

- About 50% of the carbon dioxide captured in Florida by 2030 is stored on the OCS, increasing to nearly 85% in later years of the forecast. About 20% of the captured carbon dioxide from the Southern (central Gulf Coast) region is stored on the OCS by 2040, with rest of it being stored in onshore or state water storage sites.

Discussion and Benefits Summary

- **Table 1** presents the primary economic conclusions of the study. On the whole, the addition of geologic storage (GS) on the OCS has an undiscounted cumulative net benefit to the U.S. economy of $16.9 billion between 2015 and 2054. Less than 2 percent of this benefit occurs before 2030. The size and timing of this benefit depends on many uncertain forecast assumptions such as the timing and severity of future GHG regulations, the degree to which CCS is subsidized, growth in electricity demand, the price of natural gas, the cost and practicality of building new nuclear power plants, and the cost and practicality of onshore geologic storage of carbon dioxide.

- These net benefits represent the net changes in producer surplus and consumer surplus throughout the economy. The benefit is split out among various parts of the U.S. economy including providers of GS services, EOR operators, electricity consumers, natural gas consumers and natural gas producers.

- The largest benefit ($15.46 billion, undiscounted) goes to geologic sequestration (GS) service providers and/or EOR operators[2] who will benefit from having the opportunity to develop carbon sequestration EOR projects on the OCS.

- The next largest benefit ($1.98 billion, undiscounted) is for natural gas producers as natural gas prices increase slightly. More economic CCS options on the OCS make fossil fuels more economic than nuclear and therefore reduces the amount of new nuclear builds. The reduction of new nuclear builds provides an opportunity for new natural gas-based combined cycle plants as the cost for these plants is much lower than the cost of coal plants with CCS.

- An additional benefit ($1.44 billion) goes to electricity consumers and generators, as the cost of geologic storage and transport is reduced.

- Because of the reduced number of nuclear plants, there is greater demand for natural gas and slightly higher prices for gas. This results in a small increase in gas price for consumers resulting in a negative benefit of $1.98 billion. The negative benefit to consumers represents a transfer from consumers to natural gas producers (which see a positive benefit of $1.98 billion).

The results are presented in detail in the final chapter.

[2] The companies who provide “geologic storage services” may be the same companies who are the EOR operators or they might be separate entities.

Table 1 Breakout of Economic Net Benefit by Sector
(real 2010 dollars)

Sector	Discounted Billion Dollars (2015 to 2054)	Undiscounted Billion Dollars (2015-2030)	Undiscounted Billion Dollars (2015-2054)
Electricity Consumers / Electricity Generators	+$0.41	+$0.23	+$1.44
Providers of GS Services / EOR Operators	+$2.37	+$0.03	+$15.46
Natural Gas Producers	+$0.40	+$0.40	+$1.98
Natural Gas Consumers	-$0.40	-$0.40	-$1.98
Coal Producers	*Negligible effects*	*Negligible effects*	*Negligible effects*
Coal Consumers	*Negligible effects*	*Negligible effects*	*Negligible effects*
Total	**$2.78**	**$0.26**	**$16.90**

2. U.S. Onshore and Offshore Carbon Dioxide Sequestration Potential

2.1 Introduction

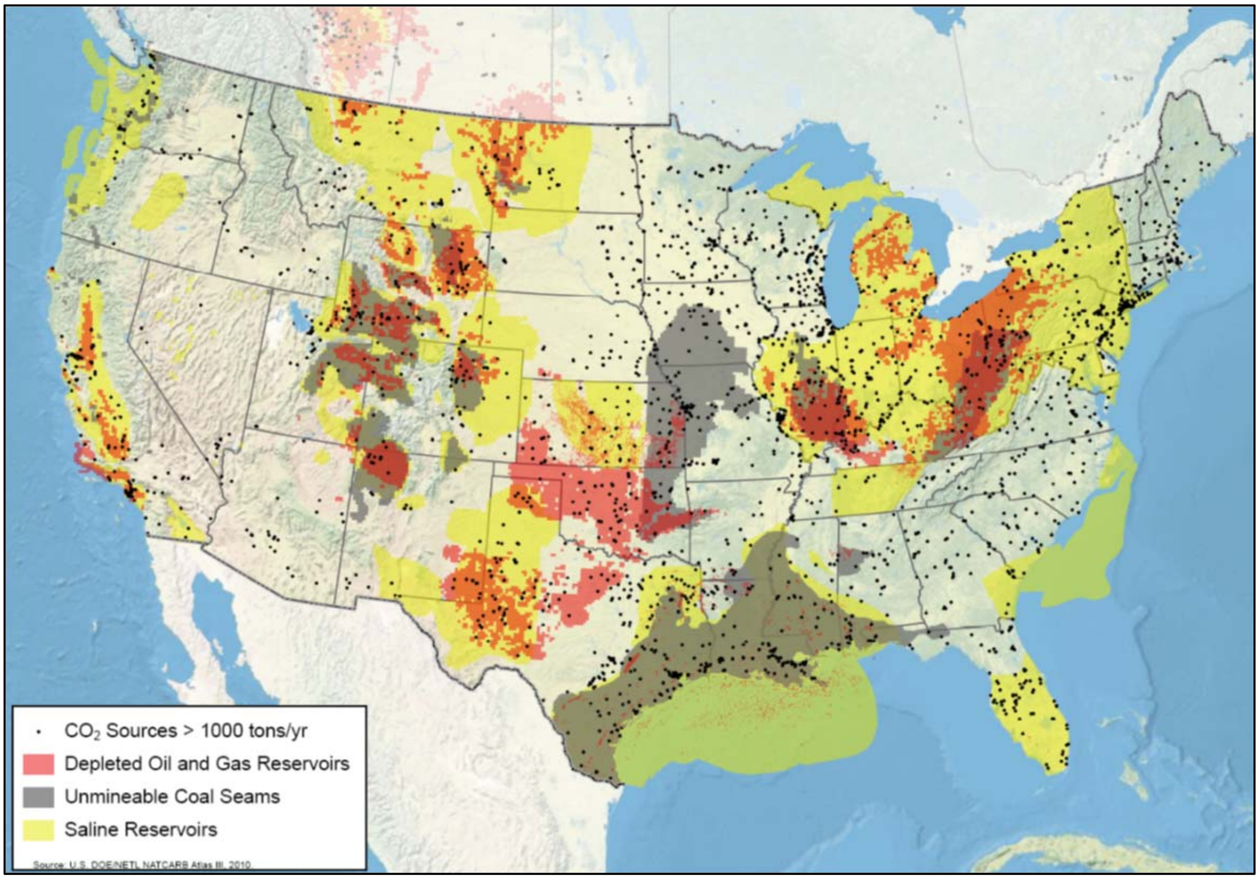
Should the U.S. develop a greenhouse gas reduction strategy that necessitates carbon capture and geologic sequestration of CO_2, there is a very large volume of assessed onshore and offshore sequestration potential available. The U.S. Department of Energy NATCARB project has determined that the Gulf of Mexico has very large potential in saline reservoirs, and there is significant potential in the Atlantic and Pacific as well. BOEM may in the future allow access to selected OCS areas for the purpose of sequestration, and the purpose of this report is to evaluate the potential for such sequestration, its costs, and the potential benefits to society of allowing offshore sequestration.

The location and nature of future offshore sequestration will depend upon a number of factors including the location of stationary CO_2 sources such as power plants and industrial sites, the volumes captured and transported, and the location of suitable offshore sequestration sites with sufficient capacity for long term storage. The potential for offshore sequestration will also depend in large part on the economics of transporting CO_2 offshore and injecting it there.

Figure 1 shows the distribution of potential U.S. geological storage sites for three categories of reservoirs: depleted oil and gas fields (red), saline reservoirs (yellow), and coal beds (gray). Many areas of the Lower-48 have large sequestration potential, as will be discussed in the next section. Saline reservoirs represent the great majority of future potential, while potential sequestration in depleted fields is also significant and can have some advantages relating to existing infrastructure and other considerations.

Offshore sequestration potential is present in the Atlantic, Gulf of Mexico, and Pacific, with most of the currently assessed potential in the central and western Gulf of Mexico. The large potential in the Gulf of Mexico is due to some of the same factors that make this a prolific oil and gas province. The Gulf also has a wide shelf area with water depths of less than 200 meters, and water depth is one of the main considerations in offshore sequestration. By contrast, the Pacific Offshore has a very narrow band of relatively shallow water. Almost all of the assessed offshore sequestration potential in the U.S. is in saline reservoirs, with some potential in depleted fields, enhanced oil recovery, and coal beds. Other potential reservoir categories such as basalt have not been comprehensively assessed, although they may turn out to be significant in the Atlantic and Pacific.

Figure 1 Potential North America CO_2 Geological Storage Areas and Major CO_2 Sources



Source: Department of Energy NATCARB GIS database[3]

[3] http://www.netl.doe.gov/technologies/carbon_seq/natcarb/stationary.html

2.2 North American Sequestration Potential

In recent years, the U.S. Department of Energy has compiled an assessment of North American CO_2 geological sequestration potential. This has been documented in the NATCARB Atlas.[4] NATCARB stands for the National Carbon sequestration database and geographic information system. The DOE effort has been managed by seven regional partnerships covering the Lower-48 and western Canada. **Table 2** summarizes the results of the regional assessments. The offshore totals are shown at the bottom of the table. Total offshore potential is assessed at approximately 3,600 billion metric tonnes (gigatonnes). It should be emphasized that the assessment of U.S. sequestration potential is an ongoing process. There is significant uncertainty in areas such as the Atlantic Offshore due to a relative paucity of data and other factors.

Almost all of the assessed potential is in saline reservoirs, with some potential in depleted fields, CO_2 enhanced oil recovery, and a minor amount in coal beds.

Table 3 summarizes the assessed onshore and offshore sequestration potential of the Lower-48 and Canada. It presents the uncertainty ranges of the DOE assessment by reservoir type for the U.S. and Canada. The great majority of offshore storage capacity is found in the Gulf of Mexico. While the Atlantic and Pacific offshore assessments are much lower, it should be noted that, in addition to the excellent geology of the Gulf, its extensive history of oil and gas development is also a factor in the assessment. The Atlantic is very sparsely drilled, as is the Pacific Northwest offshore. Thus, there is more uncertainty about potential reservoir rocks, trapping conditions, and other factors. This uncertainty is likely reflected in the assessments.

The range of uncertainty for the Lower-48 ranges from 1,790 to 20,383 gigatonnes of capacity and the range of uncertainty for the offshore is from 509 to 6,776 gigatonnes. The high assessments in each region are approximately 12 to 14 times the low assessments. Thus, there is very large uncertainty in the overall assessment. Despite this, the assessed saline volumes are very large in comparison to annual U.S. emissions, representing hundreds of years of available potential to sequester much of the U.S. emissions, even in the low assessment case.

In Canada, only onshore western Canada has been assessed, and in Alaska, only coal beds have been evaluated.

[4] U.S. Department of Energy, 2010, "2010 Carbon Sequestration Atlas of the United States and Canada (Volume III)," (NATCARB Atlas), DOE Morgantown, WV, http://www.netl.doe.gov/technologies/carbon_seq/natcarb/index.html.

Table 2 DOE NATCARB Regional Assessment of North America CO_2 Sequestration Potential

Gigatonnes	Non-EOR	CO2	Coal Seams			Saline Formations			Assessed Total		
	Depleted	Enhanced									
	Oil and	Oil			Calc.			Calc.			Calc.
Region	Gas	Recovery*	Low	High	Midpoint	Low	High	Midpoint	Low	High	Midpoint
Williston Basin and Western Canada	**24.4**	**0.6**	1.0	1.0	**1.0**	165	165	**165**	191	191	**191**
Illinois Basin	**0.9**	**0.1**	1.6	3.3	**2.5**	12	160	**86**	15	164	**89**
Michigan and Appalachia	**16.9**	**0.1**	0.8	1.9	**1.4**	46	183	**115**	64	202	**133**
Gulf Coast, GoM, and Atlantic Offsh.	**28.8**	**3.2**	33.0	75.0	**54.0**	908	12,526	**6,717**	973	12,633	**6,803**
California, Pac. NW, Pac. Offsh., AK	**2.8**	**1.2**	10.0	23.0	**16.5**	82	1,124	**603**	96	1,151	**624**
S. Rockies, Mid-Cont.,West Texas	**51.2**	**10.7**	1.0	2.0	**1.5**	219	3,013	**1,616**	282	3,077	**1,679**
N Rockies, W. Montana	**1.6**	**0.6**	12.0	12.0	**12.0**	221	3,041	**1,631**	235	3,055	**1,645**
North America Total	**126.6**	**16.5**	59.4	118.2	**88.8**	1,653	20,212	**10,933**	1,856	20,473	**11,164**
Alaska	**0.0**	**0.0**	9.0	21.0	**15.0**	0	0	**0**	9	21	**15**
Canada	**18.0**	**0.0**	0.8	0.8	**0.8**	38	51	**44**	57	70	**63**
L48 Total	**108.6**	**16.5**	49.6	96.4	**73.0**	1,614	20,163	10,889	1,790	20,383	**11,087**
onshore	**93.6**	**15.0**	48.3	93.3	**70.8**	1,123	13,407	**7,265**	1,280	13,609	**7,444**
offshore	**15.0**	**1.5**	1.3	3.1	**2.2**	491	6,756	**3,624**	509	6,776	**3,643**

Sources: 2010 NATCARB Atlas for all except CO2 EOR, which is an ICF estimate based upon DOE assessments of EOR potential.

Table 3 DOE NATCARB Assessment of North America CO_2 Sequestration Potential

Gigatonnes		2010 NATCARB II and III		
Lower 48 Only				
Category		2010 NATCARB Low Gt CO2	2010 NATCARB High Gt CO2	**2010 NATCARB Mid Gt CO2**
Depleted Oil and Gas Fields (NATCARB total less ICF EOR estimate)				
	onshore	93.6	93.6	**93.6**
	offshore	15.0	15.0	**15.0**
	subtotal	108.6	108.6	**108.6**
CO2 Enhanced Oil Recovery (ICF estimate)				
	onshore	15.0	15.0	**15.0**
	offshore	1.5	1.5	**1.5**
	subtotal	16.5	16.5	**16.5**
Coal and Coalbed Methane (all onshore)				
	onshore	48.3	93.3	**70.8**
	offshore	1.3	3.1	**2.2**
	subtotal	49.6	96.4	**73.0**
Shale Formations		0	0	**0**
Deep Saline Formations				
	onshore	1,123	13,406	**7,265**
	offshore	491	6,756	**3,624**
	subtotal	1,614	20,162	**10,889**
Offshore Saline Breakout (ICF interpretation)				
	GOM	429	5,967	**3,198**
	Pacific	15	202	**108**
	Atlantic	47	587	**317**
	Total	491	6,756	**3,624**
Onshore Saline-Filled Basalt		0	0	**0**
Lower-48 Total All Categories				
	total	**1,790**	**20,383**	**11,087**
	L48 onshore total	1,281	13,610	**7,444**
	L48 offshore total	509	6,773	**3,643**
Alaska (Coal Beds only)		9	21	**15**
Canada (Onshore Only)				
Depleted Oil and Gas		18	18	**18**
Coal		0.8	0.8	**0.8**
Shale		0	0	**0**
Saline		38	50	**44**
Total		57	69	**63**
North America Totals - All Assessed Categories				
Depleted Oil and Gas		127	127	**127**
CO2 EOR		16.5	16.5	**16.5**
Coal		59.4	118.2	**88.8**
Shale		0	0	**0**
Saline		1,652	20,212	**10,933**
Total		1,855	20,474	**11,165**

Table 4 summarizes the NATCARB assessment of U.S. offshore sequestration potential, and presents the uncertainty ranges for each reservoir category. The NATCARB study published the total offshore potential of 3,643 gigatonnes (Gt), but did not specifically break it out into Gulf of Mexico, Atlantic, and Pacific areas. ICF has evaluated the Atlas to create the distribution shown in the table. The Gulf of Mexico is estimated to have 3,198 Gt of saline potential and 16.3 Gt of potential in oil and gas fields, of which 1.5 Gt is CO_2 EOR potential. Pacific offshore saline potential is 108 Gt and there is minor potential in oil and gas fields (0.2 Gt in southern California offshore) and coalbeds (2.2 Gt in Pacific Northwest offshore). Atlantic offshore saline potential is assessed at 317 Gt.

Table 4 U.S. Offshore CO_2 Sequestration Potential

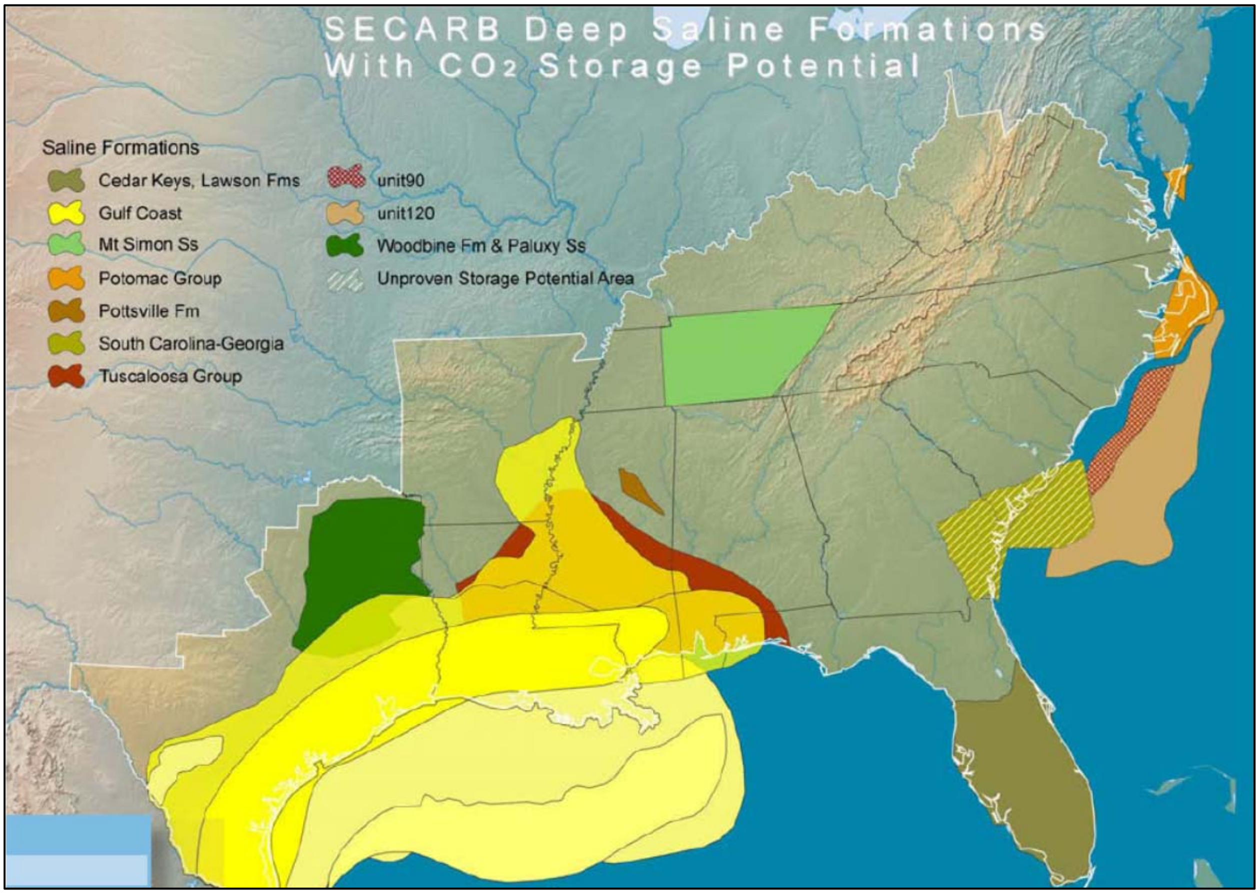
Gigatonnes

		Oil and Gas Fields			Saline			Coal Beds			Shale and Basalt	Total
		Low	High	Avg.	Low	High	Avg.	Low	High	Avg.		Avg.
Gulf of Mexico	Total	16.3	16.3	16.3	429	5,967	3,198	0.0	0.0	0.0	not assessed	**3,215**
	Depleted fields	14.8	14.8	14.8								14.8
	CO_2 EOR	1.5	1.5	1.5								1.5
Pacific Offshore	Total	0.2	0.2	0.2	14.9	201.5	108.2	1.4	3.1	2.2	not assessed	**110.6**
	Depleted fields	0.2	0.2	0.2								0.2
Atlantic Offshore		0.0	0.0	0.0	47.2	587.4	317.3	0.0	0.0	0.0	not assessed	**317.3**
Total	Total	16.5	16.5	16.5	491	6,756	3,624	1.4	3.1	2.2		**3,643**
	Depleted fields	15.0	15.0	15.0								**15.0**
	CO_2 EOR	1.5	1.5	1.5								**1.5**

Source: 2010 NATCARB Atlas with ICF allocations. The regional breakout was only partially documented in the NATCARB Atlas. The values for offshore saline potential in the Pacific and Atlantic are ICF estimates based upon analysis of the Atlas. Coalbed potential was assigned by ICF to the Pacific NW Offshore. The Atlas stated that offshore California potential in developed and undeveloped oil fields in sandstone reservoirs is 240 to 265 megatons.

Figure 2 is a map of potential storage locations in the Atlantic and Gulf Coast/Gulf of Mexico regions. The map shows the distribution of various geological formations or age units that have been assessed by DOE for potential. The Atlantic saline offshore potential is broken out by geological formation in the Atlas, but the Gulf of Mexico assessment is not. The details of these assessments are presented below.

Figure 2 Gulf Coast and Southeastern Potential Saline Storage Formations



Source: DOE NATCARB Atlas III, 2010

Gulf of Mexico Assessment

The DOE SECARB partnership, whose area includes the offshore south Atlantic and the Gulf of Mexico, has been working with the Texas Bureau of Economic Geology to re-assess the storage potential of the Gulf of Mexico OCS and state offshore.[5, 6] Goals of the overall BEG project include the evaluation of reservoirs and seals, storage assessment, and risk analysis. Another objective is to identify and rank identified potential storage sites and to identify at least one site that can accept at least 30 million tons of CO_2.[7]

[5] Litynski, J.T., et al., 2011, "Carbon Capture and Sequestration: The U.S. Department of Energy's R&D Efforts to Characterize Opportunities for Deep Geologic Storage of Carbon Dioxide in Offshore Resources," 2011 Offshore Technology Conference paper OTC-21987-PP.
[6] SECARB partnership website http://www.secarbon.org/
[7] Texas BEG website http://www.beg.utexas.edu/gccc/miocene/

In addition, SECARB has been researching a range of legal and regulatory issues related to transport and storage of CO_2 in the Gulf of Mexico.[8] This effort is looking at both state and national issues.

As stated above, NATCARB assessed the Gulf of Mexico but only published aggregate results. The Texas Bureau of Economic Geology recently presented results of their work to assess the Gulf of Mexico OCS.[9] The study, which is summarized in **Table 5 and Figure 3**, covered the federal portion only of offshore Texas and Louisiana. The assessment indicated 558 gigatonnes of saline potential. This is much less than the NATCARB assessment shown in **Table 3** of approximately 3,200 gigatonnes.

It should be noted that the BEG study included only the Oligocene, Miocene and Pliocene sections (excluded Paleocene, Eocene and Pleistocene) because they excluded parts of the stratigraphic section that are generally below 15,000 feet drill depth or in more than 1,000 feet of water. The NATCARB assessment appears to cover a very similar if not identical part of the geologic section. However, NATCARB did apparently include some areas off of Mississippi and Alabama that were not covered by the BEG study. A separate project is underway by BEG for the state offshore areas of Texas.

For the current study, ICF has used the BEG assessment only to allocate the NATCARB-based 3,200 gigatonnes of Gulf of Mexico saline potential by geologic age, as shown in **Table 5**.

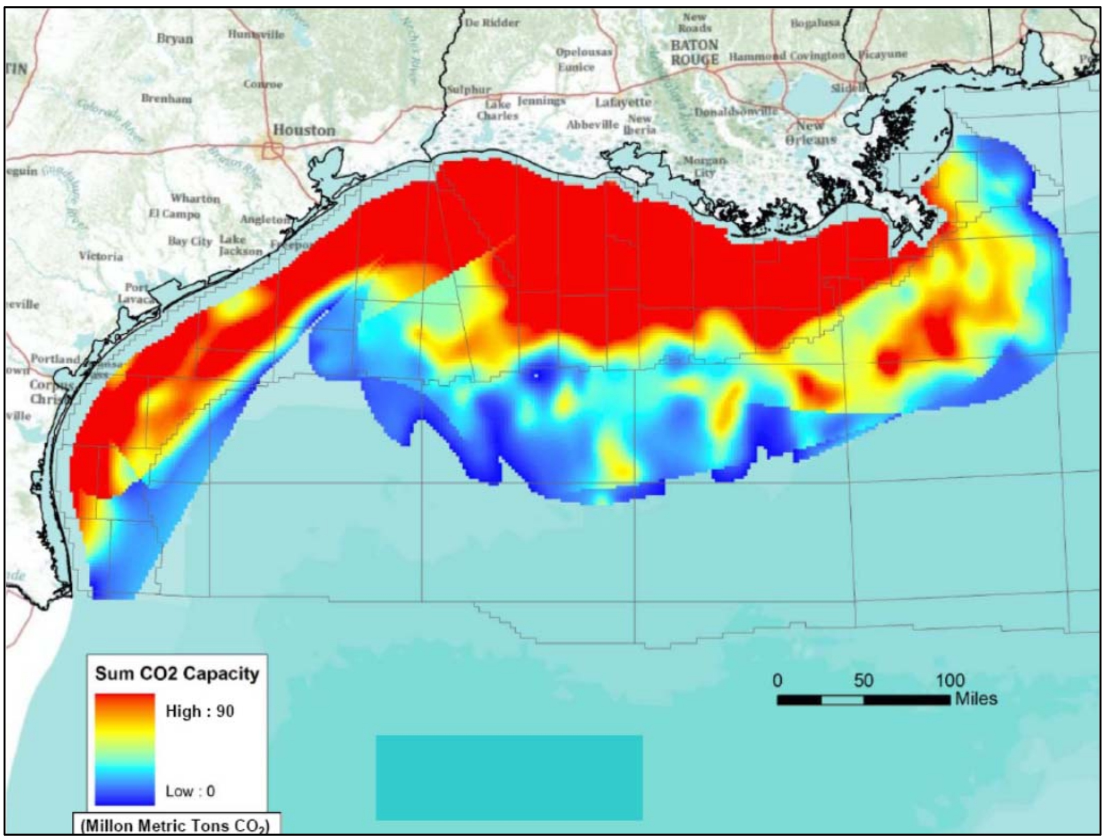
Table 5 Allocation of Gulf of Mexico Saline Sequestration Potential by Age

	2011 BEG Assessment Gigatonnes	%	Allocation of Estimated NATCARB Volumes Gigatonnes
Upper Pliocene	105	18.8%	602
Lower Pliocene	144	25.8%	826
Upper Miocene	199	35.7%	1,141
Lower Miocene	89	15.9%	510
Oligocene	21	3.8%	120
Total	558	100.0%	3,200

[8] http://www.secarbon.org/files/CCS_Legislation_2011.pdf
[9] Carr, David, 2011, "Geological CO_2 Sequestration Capacity Estimate – Offshore Northern Gulf of Mexico," presentation slides March 9, 2011, Texas Bureau of Economic Geology Gulf Coast Carbon Center, http://www.sseb.org/wp-content/uploads/2011/03/DavidCarr.pdf.

The BEG assessment map shows that the great majority of the assessed volumes are on the shelf (less than 200 meters water depth). This results largely from excluding the portions of the geologic section that are in deep water. The Louisiana OCS appears to hold much more potential than the Texas OCS, although the Texas resource is very substantial. The BEG study mapped and assessed the distribution of storage potential in each geological interval.

Figure 3 Map Showing Recent BEG Assessment of Storage Potential in Gulf of Mexico OCS



Source: Carr, 2011

In addition to the work BEG is doing, there is a large amount of geological information on the Gulf of Mexico in the 2001 MMS (BOEM) Gulf of Mexico Atlas.[10] Play level information includes the range of distance offshore, water depths, and drilling depth intervals. For example, Miocene oil and gas plays in the OCS had mean drilling depths

[10] U.S. Minerals Management Service (BOEM), 2001, “Atlas of Gulf of Mexico Gas and Oil Sands as of January 1, 1999,” MMS Report 2001-086.

in the range of 8,500 to 10,900 feet and Pliocene plays ranged in mean depth from 9,100 to 12, 400 feet. Individual reservoirs within these plays represent a much wider depth range. This information could be useful for future offshore sequestration studies.

In addition to saline sequestration potential, the Gulf of Mexico has 14.8 Gt of assessed potential in depleted oil and gas fields and 1.5 Gt of CO_2 EOR potential, as shown in Table 4. Oil fields in the Gulf of Mexico are concentrated in the area offshore of Louisiana, while offshore Texas tends to be more gas-prone. Thus, depleted oil field potential and CO_2 EOR potential is mostly offshore Louisiana.

Atlantic Offshore Assessment

Table 6 presents the NATCARB assessment of southern Atlantic offshore saline sequestration potential and **Figures 4 and 5** are maps of the area. Most of the potential is in the "Unit 120" area, which is shown in tan offshore of North Carolina and South Carolina. Unit 120 consists of Lower Cretaceous saline sands. "Unit 90", shown in red/brown in the offshore, consists of Upper Cretaceous saline sand reservoirs.[11] These units range from 25 to 75 km offshore in water depths of 50 to 1,000 meters. Drilling depths range from 2,000 to 10,000 feet below the sea floor. A small amount of potential exists in the Potomac Group offshore North Carolina and Virginia, and in offshore South Carolina.

Table 6 Details of Southern Atlantic Offshore Potential

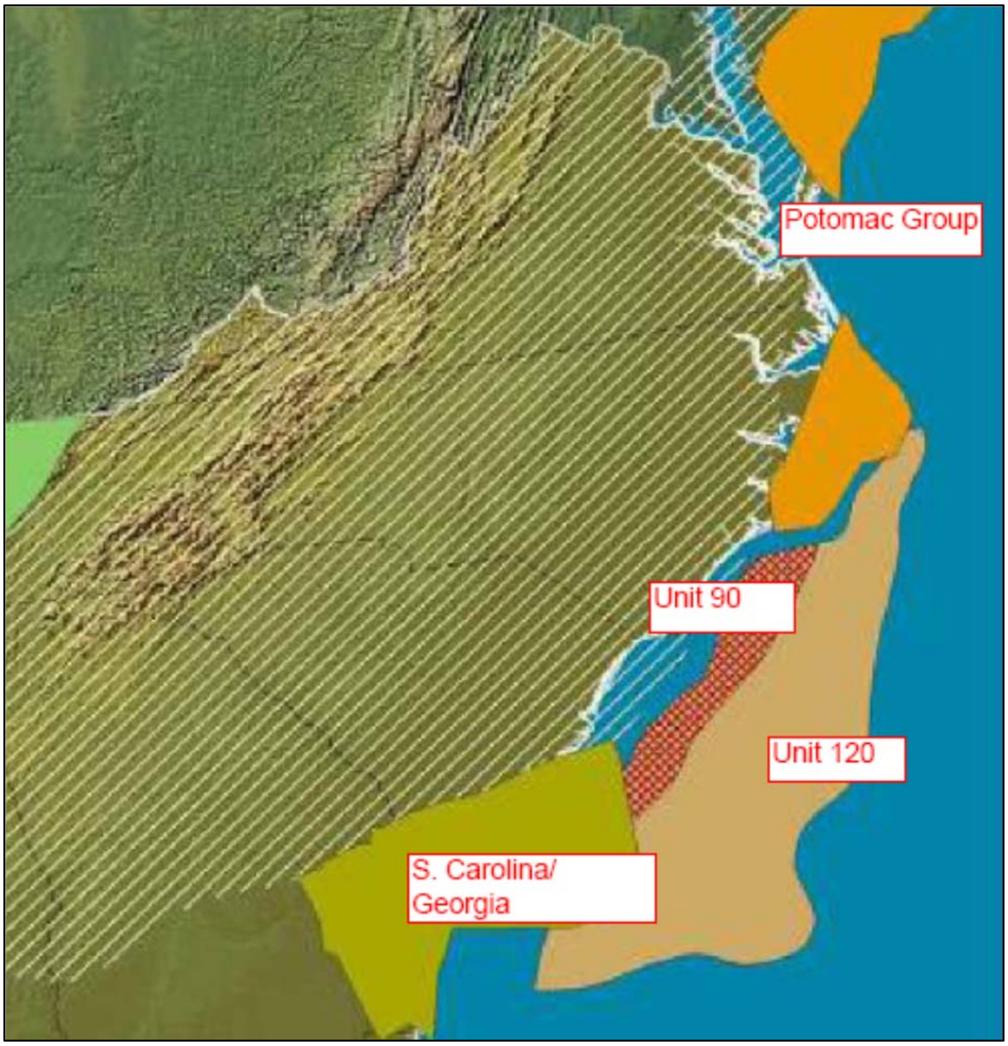
Gigatonnes of Saline Potential

	Low Gt	High Gt	Mean Gt
Unit 120 (all offshore)	36.00	490.00	263.00
Unit 90 (all offshore)	3.00	43.00	23.00
Potomac Group (all offshore)	2.00	25.00	13.50
South Carolina/Georgia (offshore)	6.17	29.40	17.79
Total	47.17	587.40	317.29

Note: Assumes 49% of SC/GA assessment is offshore (ICF allocation)
Source: NATCARB

[11] Smyth, et al., 2007, "Potential Sinks for Geologic Storage of CO_2 Generated in the Carolinas," Texas BEG Gulf Coast Carbon Center Publication 07-01.

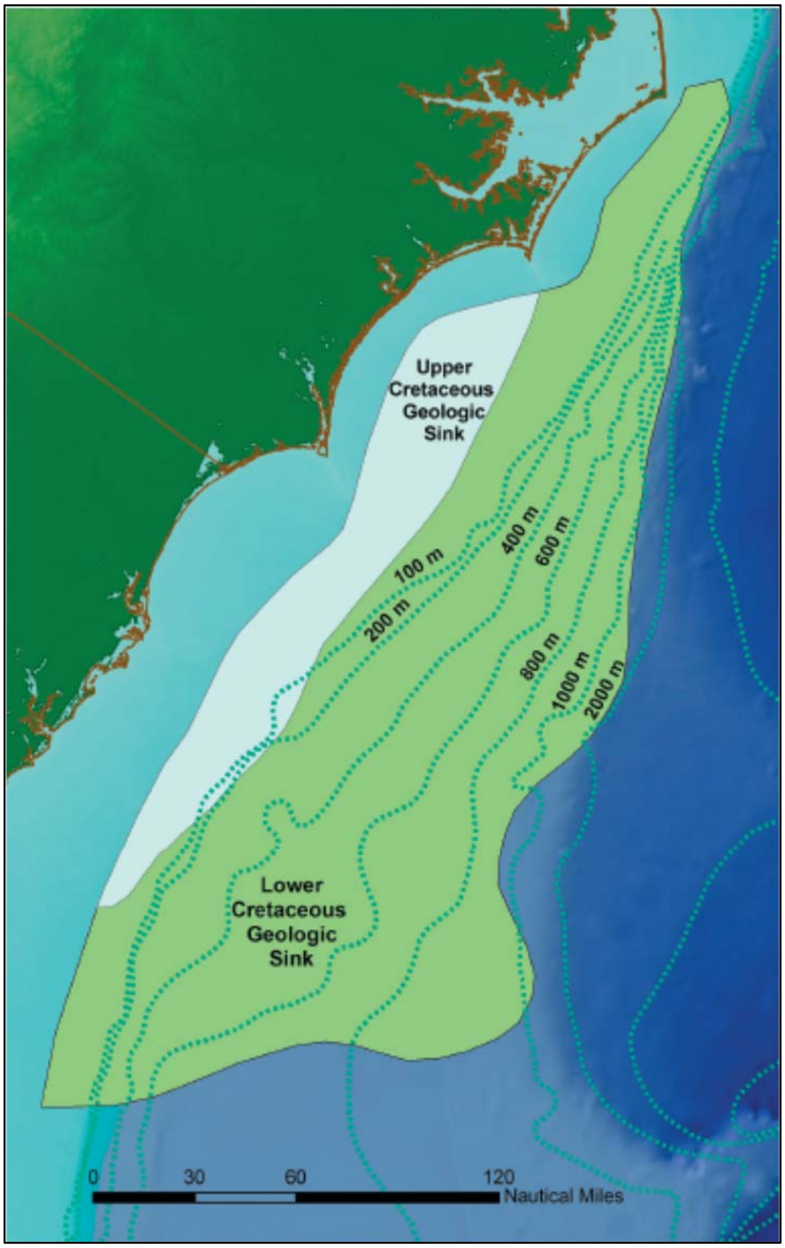
Figure 4 Southern Atlantic Offshore Assessment Units



Source: modified from Nemeth, 2008[12]

[12] Nemeth, K.J., 2008, SECARB presentation for IOGCC, Nov. 17, 2008.

Figure 5 Water Depth Contours and Units 90 and 120 - Southern Atlantic



Source: Smyth, et al., 2007

There is also sequestration potential in the northeastern Atlantic OCS off of New Jersey and New York. Recently the New York State Geological Survey and the MRCSP partnership published a preliminary evaluation of the sequestration characteristics of the

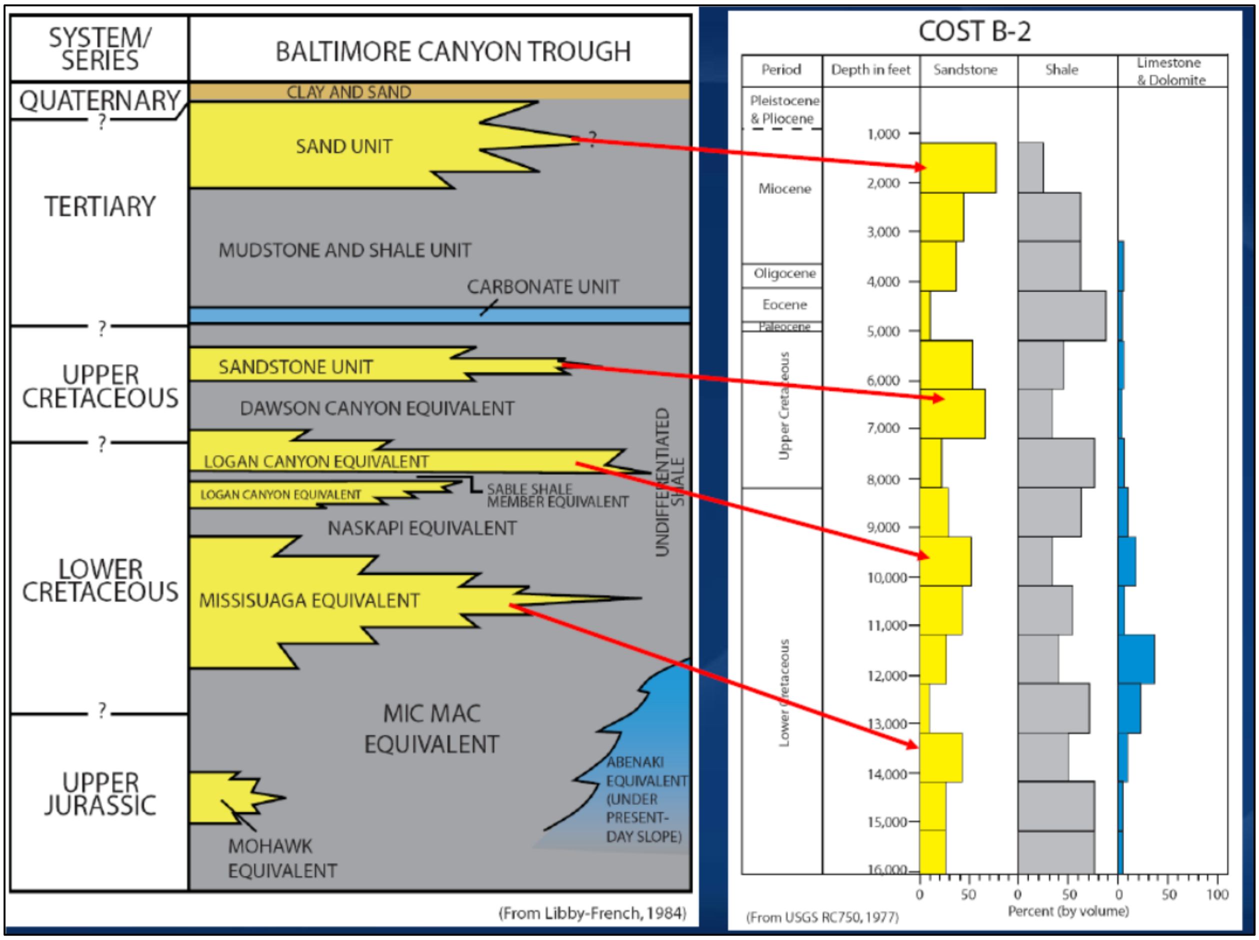
Baltimore Canyon area.[13] They state that there are many favorable aspects of this area, including porous and permeable Cretaceous age sandstones, sealing units, structures, shallow water depths, and existing well control. The stratigraphic column is shown in **Figure 6**. Porosities are reported to be up to 30% and permeabilities up to 1,200 millidarcies. (Porosity represents the void space in the rock and permeability measures fluid flow capacity through the reservoir).[14] A preliminary storage assessment is being developed. The area is also in close proximity to numerous CO_2 sources, and offshore sequestration in this region could avoid many of the possible difficulties of siting onshore projects.

Researchers with Schlumberger recently published a paper stating that they have evaluated logs and other data near the COST-B-2 well offshore New Jersey.[15] They concluded that Lower Cretaceous sands have porosity and permeability in ranges that are adequate for CO_2 injection and sequestration. They also found that the sealing shale intervals were very good.

An offshore Atlantic geological sequestration project has been proposed for this area by SCS Energy. The PurGen One project involves the capture of CO_2 at a proposed 400 MW Integrated Gasification/Combined Cycle power plant in Linden, New Jersey and transportation of the CO_2 70 miles offshore to an injection site through a 140 mile pipeline.[16] The proposed location of the pipeline is shown in **Figure 7**. The CO_2 would be injected into a Cretaceous age saline sandstone formation approximately 8,000 feet below the sea floor in a water depth of about 300 feet. While there is no oil or gas production in the area, a significant amount of exploratory drilling was done by industry in the 1970s, providing a preliminary understanding of the subsurface geology.

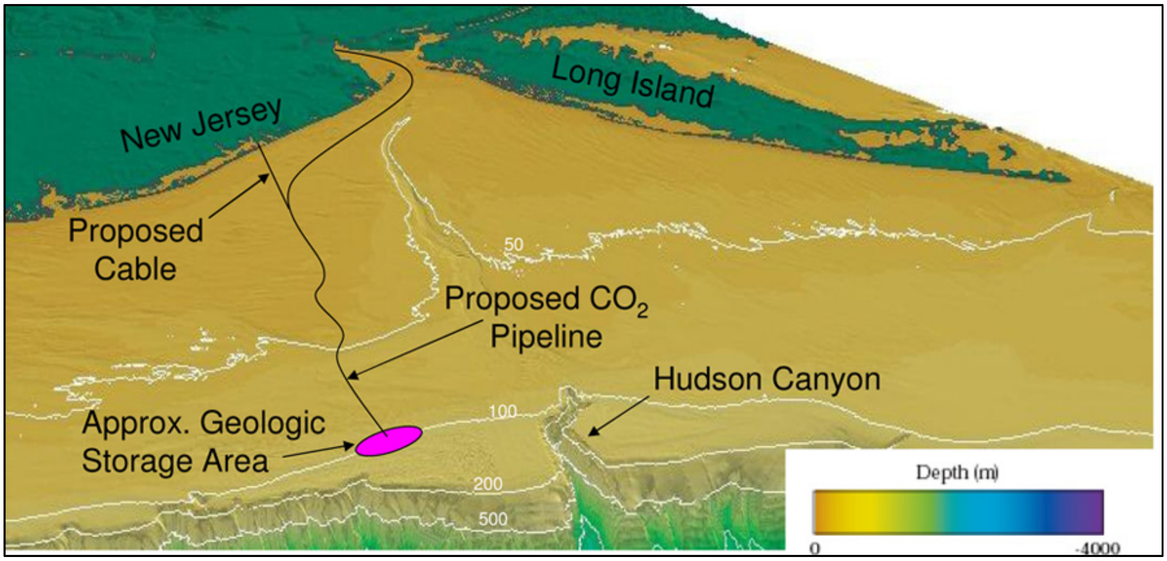
[13] Slater, et al., 2010, "Potential for Supercritical Carbon Sequestration in the Offshore Bedrock Formations of the Baltimore Canyon Trough," MRCSP DOE Partnership, September 28, 2010 slide presentation, http://www.searchanddiscovery.com/documents/2011/80143slater/ndx_slater.pdf.
[14] Litynski, et al., ibid.
[15] Brown, A.L., et al., 2011, "Carbon Capture and Sequestration: Ascertaining CO_2 Storage Potential, Offshore New Jersey, USA," 2011 Offshore Technology Conference Paper OTC 21995.
[16] PurGen One website http://www.purgenone.com/

Figure 6 Stratigraphy of Offshore Northeast Atlantic



Source: Slater, et al., 2010

Figure 7 Planned Location of Proposed SCS Energy PurGen One CO_2 Pipeline



The locations of the pipeline and injection well area are based on an interpretation of the image and have not been geo referenced.

ESS Group, Inc.
Engineers
Scientists
Consultants

SCS PureGenOne
Carbon Sequestration Project Area

Perspective View of Preliminary Pipeline & Cable Route

Source: http://pubs.usgs.gov/of/2004/1441/images/pdf/fig1.pdf

Source: PurGen One[17]

In addition to the Cretaceous sandstone storage potential in the offshore northern Atlantic, there is also potential for storage in saline filled basalts associated with Triassic age faulting onshore and offshore in the New York, New Jersey area. The basalt storage potential has apparently not been evaluated by NATCARB but there has been recent work by academic groups to quantify the potential.[18]

Pacific Offshore Assessment

Table 7 presents an ICF analysis of the NATCARB Pacific offshore saline reservoir assessments. The offshore potential figures are ICF estimates based upon published data and charts by NATCARB. Of the 108 Gt of potential, an estimated 91 Gt is in offshore California and 17 Gt is offshore of Washington State. Oregon may have some

[17] http://www.purgenone.com/about-scs-energy.php

[18] Goldberg, et al., 2010, "Potential Onshore and Offshore Reservoirs for CO_2 Sequestration in Central Atlantic Magmatic Province Basalts," http://www.pnas.org/content/107/4/1327.

offshore potential as well, but it was not possible to determine this from the published Atlas data.

Figures 8 and 9 are maps of the southern Pacific offshore sequestration areas. **Figures 8** shows the basin areas and **Figure 9** shows the water depths. Approximately 20 basins are present offshore of Southern California.

In an effort to better determine the offshore potential, the West Coast Regional Carbon Sequestration Partnership (WESTCARB) group is evaluating both the saline potential and the potential in discovered oil fields.[19] The primary difficulty with evaluating offshore southern California potential is the lack of well control across most of the region. The group has done a preliminary assessment of the saline potential and assessed the potential for storage in existing oil fields (exclusive of the Monterey formation, which is the primary oil-productive interval). Oil and gas field potential was assessed at 236 million tons, a small fraction of the saline reservoir potential.

Table 7 Details of Pacific Offshore CO_2 Sequestration Potential

Gigatonnes of Saline Potential	Low Gt	High Gt	Mean Gt
California Onshore	30.1	413.5	221.8
Oregon Onshore	7.1	97.4	52.3
Washington Onshore	29.9	411.6	220.8
Onshore total	67.1	922.5	494.8
WESTCARB region total	82.0	1,124.0	603.0
Difference = WESTCARB offshore	14.9	201.5	108.2
Breakout of Offshore			
Washington (from 2008 report chart)	7.0	27.0	17.0
Oregon (assumed zero)	0.0	0.0	0.0
California (total less WA offshore)	7.9	174.5	91.2
Total	14.9	201.5	108.2

Source: NATCARB with ICF interpretation.

[19] Clinkenbeard, John, 2010, "California: Assessment of Offshore Potential and Screening for Salinity in the Southern Sacramento Basin," WESTCARB presentation, October 20, 2010.

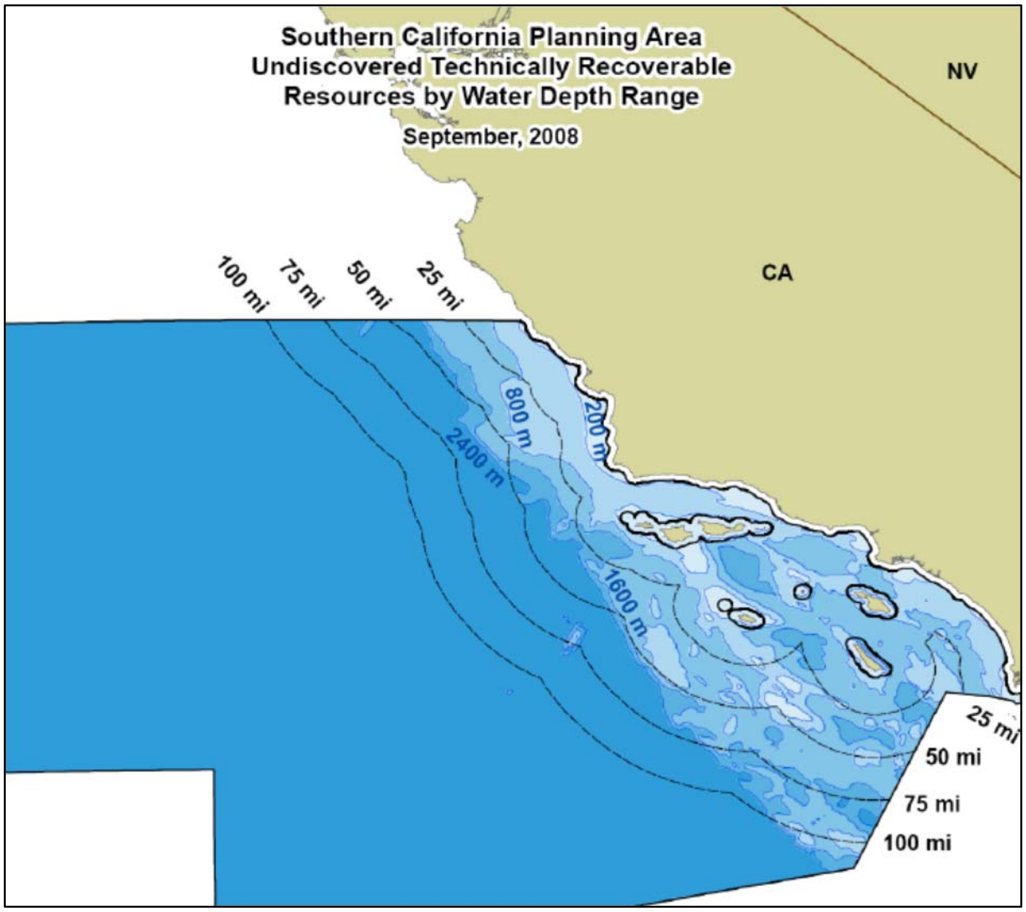
Figure 8 Offshore Southern Pacific Region Potential Storage Basins and Stationary Sources

Yellow symbols are power plants, blue symbols are refineries, red symbols are oil and gas facilities, and gray symbols are cement plants.

Source: WESTCARB presentation, October, 2010[20]

[20] http://www.csub.edu/~dbaron/Myhre10.pdf

Figure 9 Water Depth Map for Southern California

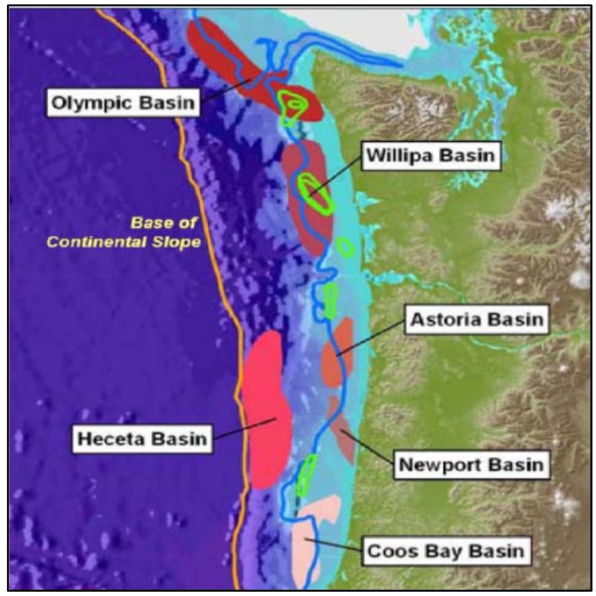


Source: BOEM[21]

Figures 10 and 11 show the offshore basin locations and water depths in the Pacific Northwest, respectively. The right hand side of **Figure 10** is a detailed map of the offshore basins. WESTCARB has done some geological evaluation of the offshore basins.[22] There are six basins with up to 15,000 feet of sediments. Good storage potential exists in the Miocene Montesano formation, which is a sandstone formation with good porosity (15 – 24%) and permeability (up to 1,000 md) and is overlain by a shale interval. As in the southern Pacific region, water depths increase rapidly offshore. As shown in **Figure 11**, the 800 meter depth line is about 30 - 40 miles offshore.

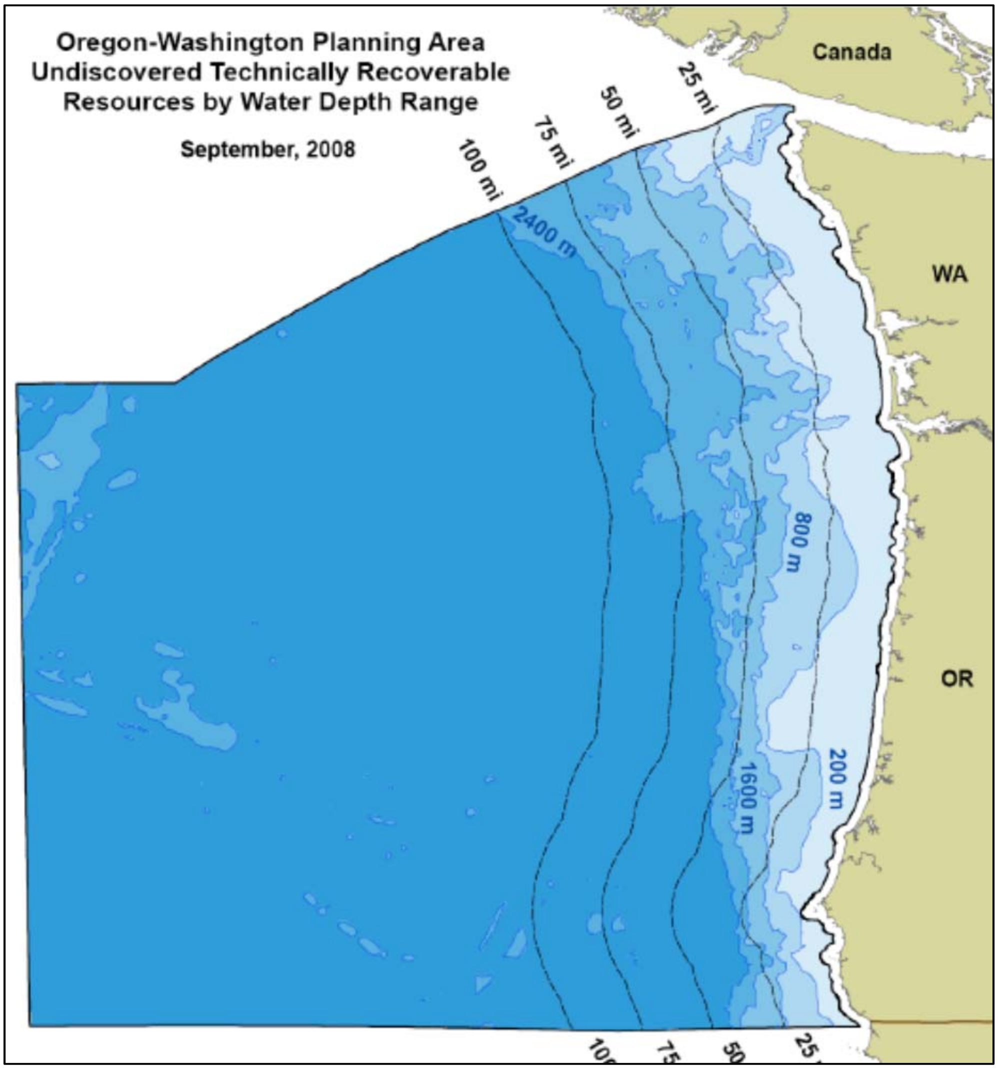
[21] http://www.boemre.gov/revaldiv/NatAssessmentMap.htm
[22] Thomas, S.D., 2007, "Characterization of Sedimentary Basins in Washington and Oregon," WESTCARB presentation, November 27, 2007.

Figure 10 Pacific Northwest Potential Storage Basins



Sources: NATCARB Atlas (left) and Thomas, 2007 (right)

Figure 11 Water Depth Map for Pacific NW



Source: BOEM[23]

[23] http://www.boemre.gov/revaldiv/NatAssessmentMap.htm

3. U.S. Stationary CO_2 Emission Sources

3.1 Introduction

An interesting statistic relative to potential offshore GS is that approximately one-half of the U.S. population now resides within 50 miles of the coast.[24] This concentration of population near the coast increases the significance of potential future offshore CO_2 sequestration. Stationary emission sources near the coast are those that could most economically benefit from offshore sequestration.

Power generators and particularly coal-fired power plants located near offshore areas, are of considerable importance to the current study. Emissions from industrial plants will also be very significant for potential capture and storage.

According to the US Department of Energy – Energy Information Administration (EIA), the U.S. economy emitted approximately 5.8 gigatonnes of CO_2 emissions in 2008 from fossil fuel combustion. This figure includes emissions of CO_2 from non-fuel use of fossil fuels in the industrial and transportation sectors. When these figures have been eliminated, total CO_2 emissions from fossil fuel combustion throughout the U.S. economy amounted to approximately 5.6 gigatonnes, with about 3.8 gigatonnes from stationary sources.

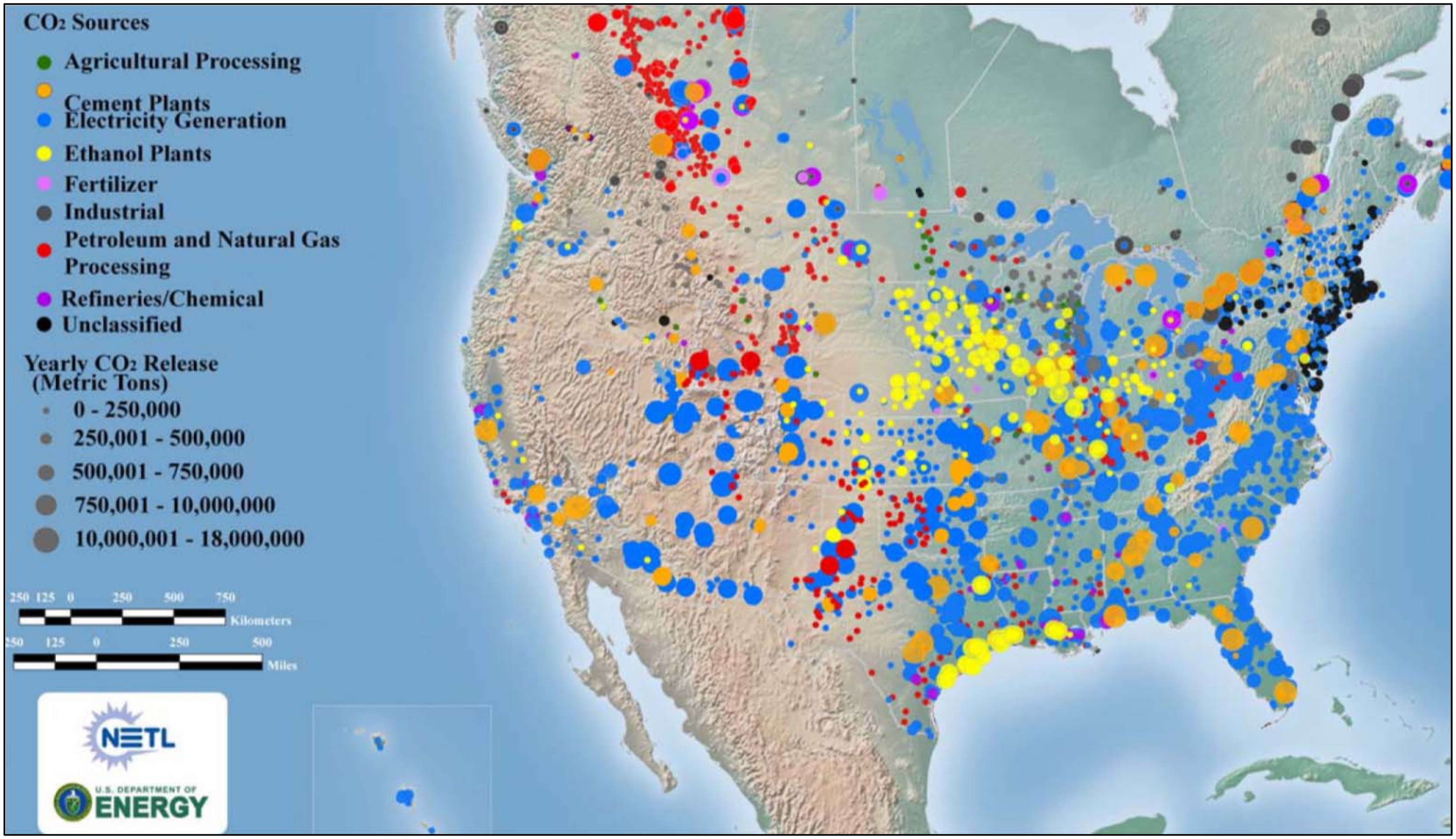
Figure 12 is a map of North American stationary sources of CO_2 emissions. The source of this information is the NATCARB atlas. The map shows that most of the sources are found in the eastern and central portions of the country, with a significant concentration in the Southwest as well. Power generation plants are shown in blue on the map.

Figure 13 illustrates the distribution by type of source, drawn from the US DOE NETL NATCARB dataset for stationary emission sources. There are eight categories plus “unclassified.” Total annual emissions from stationary sources (including Canada) were 3,505 gigatonnes. Lower-48 emissions were 3,108 gigatonnes from 4,027 sources.

Electric generating plants are the largest emitter of CO_2 at 76.4%, followed by the following source categories in decreasing order: refineries and chemical facilities (5.7%), industrial facilities including iron and steel manufacturing (5.0%), petroleum or natural gas processing facilities (3.9%), cement and lime plants, ethanol plants, miscellaneous sources (e.g. waste processing, landfills, military operations), fertilizer production, and agricultural processing facilities.

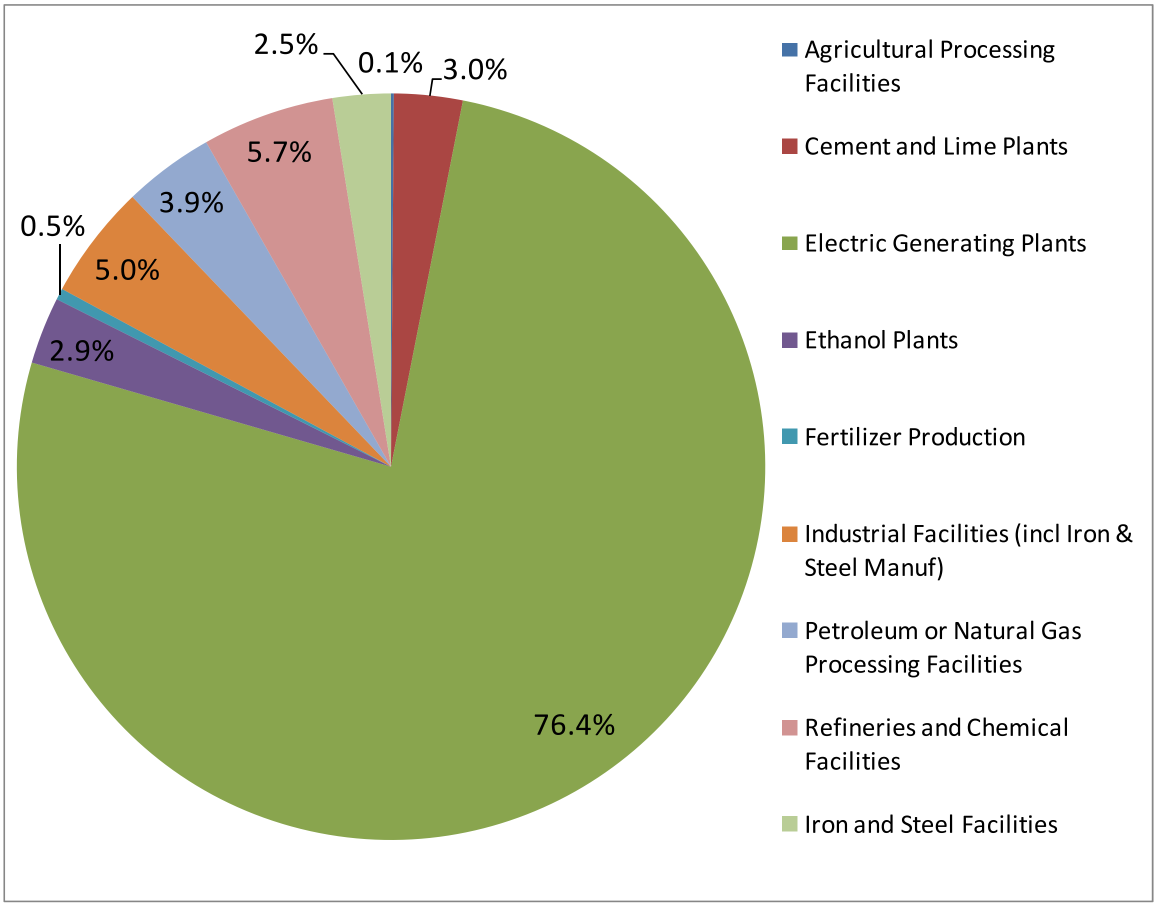
[24] NOAA http://oceanservice.noaa.gov/facts/population.html

Figure 12 Stationary CO_2 Sources in North America



Source: NATCARB Atlas

Figure 13 Distribution of Annual North America Stationary U.S. CO_2 Emissions by Sector



Source: NATCARB Atlas data

3.2 CO_2 Sources by Region and Source Type

Table 8 summarizes the regional emissions from stationary sources for the Lower-48 only. The regions shown in the table are the NATCARB partnership regions. The table shows the annual emissions by category for each region, and the total number of sources in the database. With the exception of the Northern Rockies and New England, the emissions from most regions are dominated by coal fired power generation. Refineries are concentrated along the Gulf Coast and Midwest. Industrial emissions are concentrated in the Midwest.

Table 8 Annual Lower 48 CO_2 Emissions by Region and Category

Source: NATCARB sources database, 2010; Excludes Canada sources.

			Million Tonnes per Year								
DOE Partnership	Region	No. Sources	Power Generation	Industrial	Refineries/ Chemical	Cement	Fertilizer	Ethanol	Petroleum/ Nat. Gas	Other	Total
Big Sky	W. MT, WY, ID	214	9.99	6.38	0.20	3.08	0.20	3.30	3.12	1.88	28.15
MGSC	Illinois Basin	229	228.69	7.74	9.49	6.18	0.43	11.15	1.89	0.01	265.58
MRCSP	Appalachia/Michigan	353	582.02	67.28	23.94	14.55	0.89	4.49	5.66	0.00	698.83
New England	New England	944	9.58	0.00	0.00	0.00	0.00	0.00	0.00	85.26	94.84
PCOR	Midwest, Williston, and W. Can.	628	302.84	54.41	14.08	10.40	1.81	26.24	1.74	4.88	416.40
SECARB	Southeast/Gulf Coast	908	866.54	2.56	72.91	31.46	6.84	49.99	12.36	0.00	1,042.66
SWP	Southwest/Mid-Cont./S. Rockies	452	323.10	0.00	0.00	12.60	0.00	5.23	13.35	0.00	354.28
Westcarb	Calif. snd Pac. NW	299	170.71	0.00	26.82	8.39	0.00	1.11	0.00	0.00	207.03
Totals		4,027	2,493.47	138.37	147.44	86.66	10.17	101.51	38.12	92.03	3,107.77

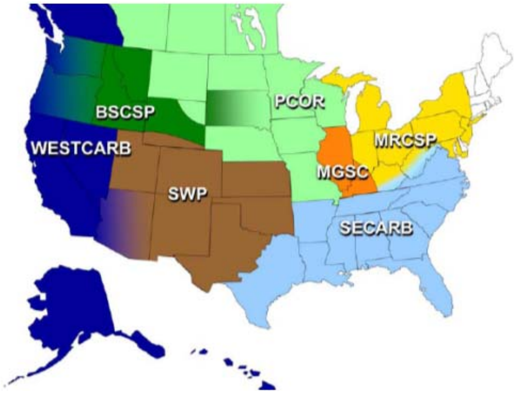
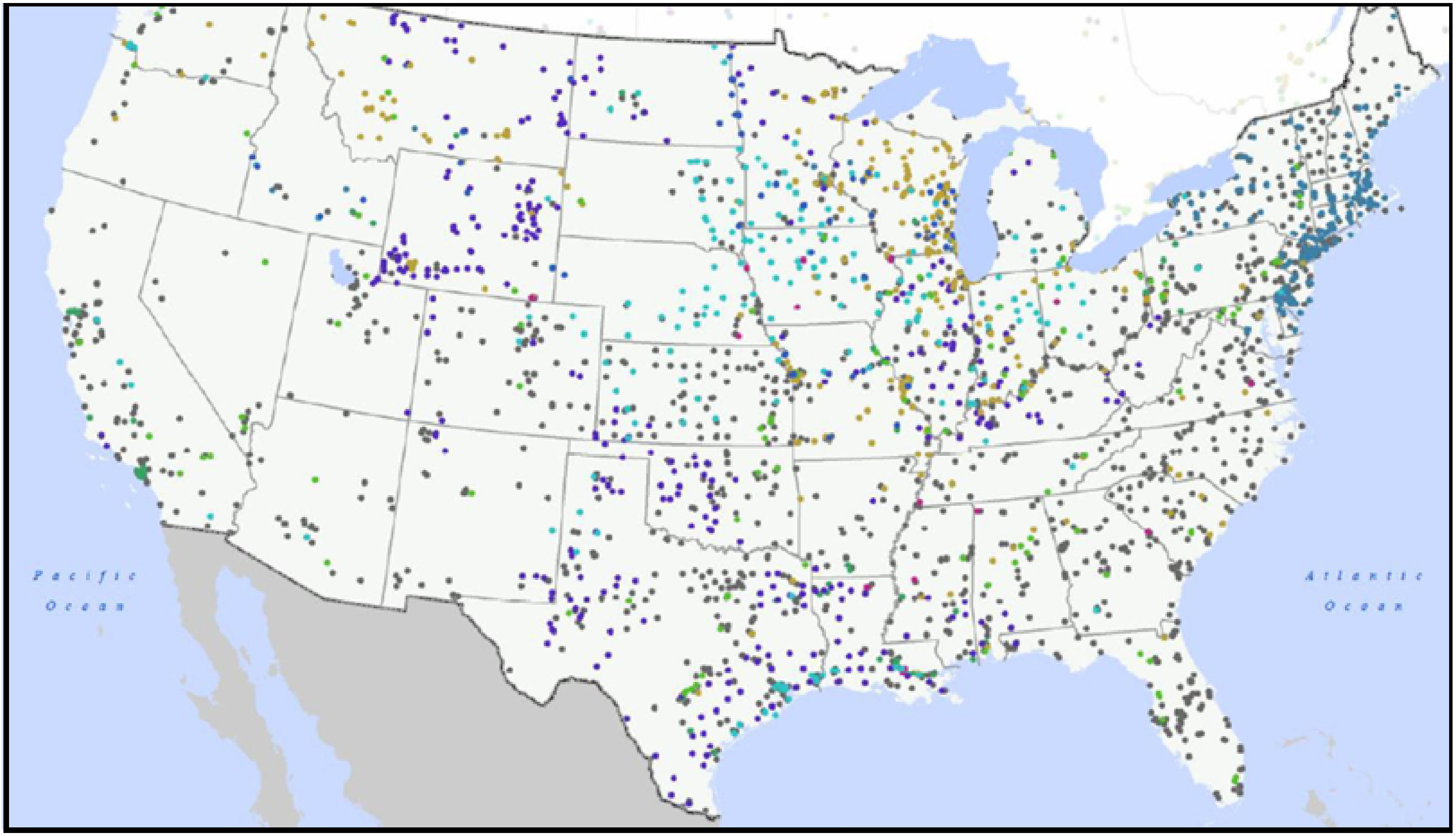


Figure 14 is a more detailed map showing stationary sources by type.
Figures 15 and 16 illustrate the emissions rate of individual CO_2 emission sources. The categories shown are: less than 1.5 million tonnes (megatonnes) per year, 1.5 to 5.0 megatonnes, 5.0 to 15 megatonnes, and greater than 15 megatonnes per year.

Figure 14 Detailed Map of U.S. Stationary CO_2 Sources by Type



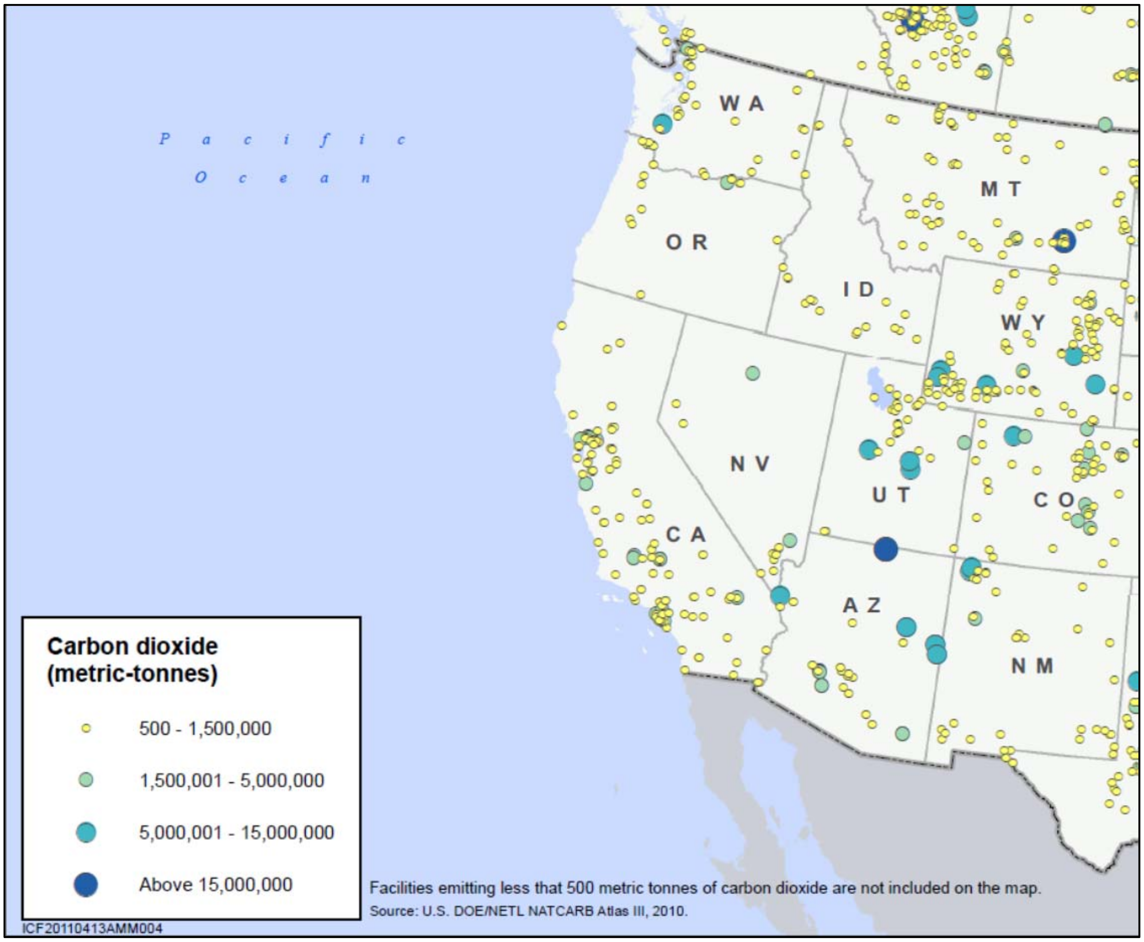
Source: US DOE NETL NATCARB GIS Data (legend on next page)

(Legend for Figure 14)

- Agricultural or Food Processing Facility
- Cement Plant or Lime Production Facility
- Coal
- Ethanol Plant
- Fertilizer or Ammonia Production Facility
- Industrial/Manufacturing Facilities (Non-Chemical or Petroleum)
- Petroleum, Natural Gas Processing or Transmission
- Petroleum refinery or chemical production plant
- Other CO2 source

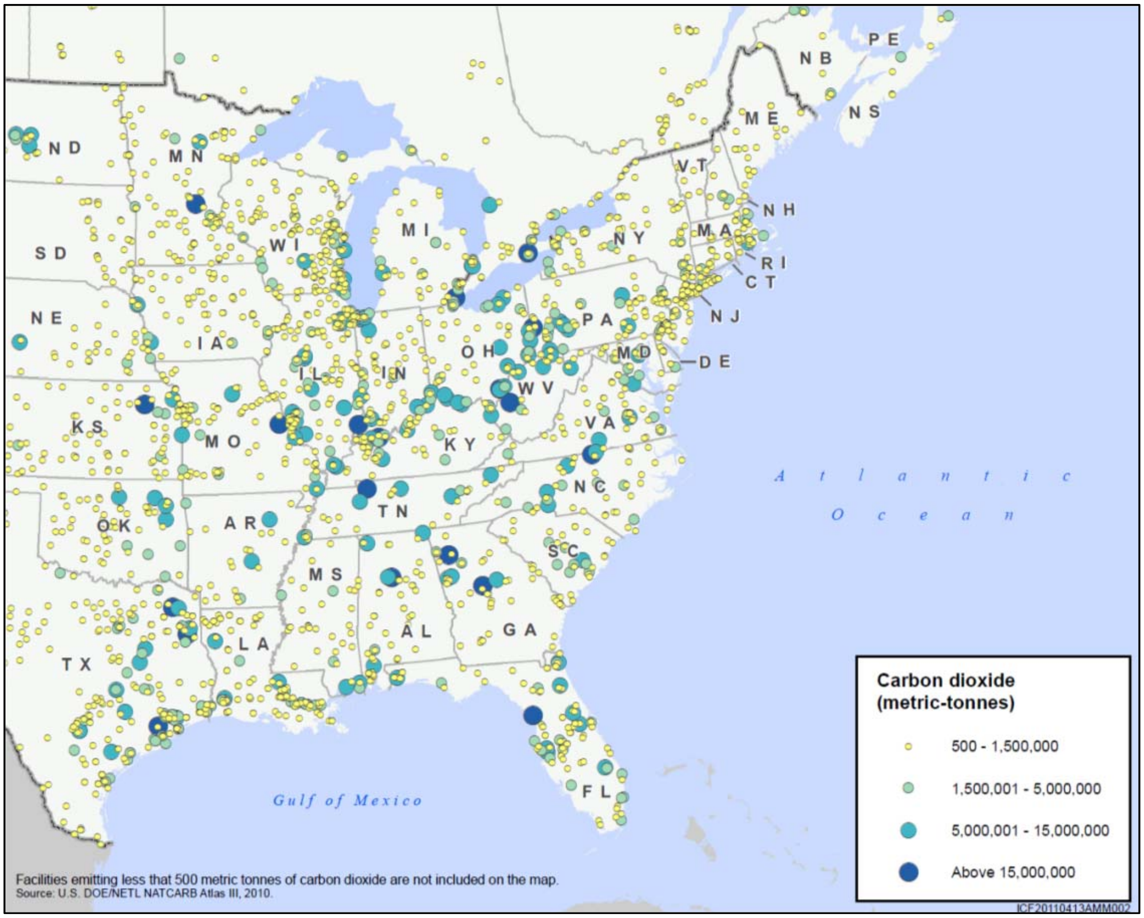
Source: U.S. DOE/NETL NATCARB Atlas III, 2010.

Figure 15 Major Stationary Sources - Western U.S.



Source: US DOE NETL NATCARB GIS Data

Figure 16 Major Stationary Sources - East Coast and Gulf Coast



Source: US DOE NETL NATCARB GIS Data

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4. Federal and State Regulatory Policies and Outlook for CCS Volumes

4.1 Regulatory Overview

In recent years, Congress has considered a number of economy-wide greenhouse gas (GHG) cap-and-trade programs and other GHG regulatory concepts. However, this effort has stalled due to the current political climate. Congress is not currently considering any comprehensive federal greenhouse gas regulations and it is not expected that there will be any such bills in the near future, which is in sharp contrast to years past. This lack of activity on GHG regulations will have an impact on CCS deployment since a stringent economy-wide bill resulting in a high carbon price would greatly encourage investment in CCS. A review of current Congressional activity and major legislative proposals over the past several years is discussed below.

In addition, there are a couple of regional greenhouse gas programs that are in various stages of development and some state initiatives. The Regional Greenhouse Gas Initiative (RGGI), a mandatory GHG cap-and-trade program applicable to power plants is currently operating in the Northeast, and the Western Climate Initiative (WCI) is still moving forward despite the withdrawal of some participants. The Midwest Greenhouse Gas Reduction Accord (MGGRA) has been dissolved. The only state program nearing completion is California's cap-and-trade program, but it is currently stalled due to litigation. Nevertheless, there are some states that have passed CCS-specific regulations that are noted below.

4.2 Review of Federal and State Policies

CCS deployment remains a federal priority, President Obama established an Interagency Task Force on Carbon Capture and Storage (CCS) in February 2010. Energy Policy Act of 2005 and the 2009 American Recovery and Reinvestment Act (ARRA), contained provisions for the promotion of CCS. Despite these actions, momentum on a comprehensive federal greenhouse gas program, a key driver for CCS, has stalled. There are currently no major comprehensive climate change bills being considered. A number of legislative proposals in the past couple of years included provisions related to CCS:

American Power Act (APA) of 2010 – Kerry-Lieberman[25];

S. 1462, American Clean Energy Leadership Act (ACELA) of 2009 -- Bingaman;

[25] Discussion draft released on May 12, 2010.

S. 2877, Carbon Limits and Energy for America's Renewal (CLEAR) Act -- Cantwell-Collins;

S. 3464, Practical Energy and Climate Plan (PECP) Act of 2010 -- Lugar, Graham & Murkowski; and

H.R. 2454, American Clean Energy and Security Act (ACES Act) of 2009 -- Waxman-Markey.

Although the approaches and other provisions in the bills differ, most of the bills authorized funding for development and demonstration of CCS technologies, created incentives for commercial deployment of CCS, and addressed to some extent legal and regulatory issues.[26] For example, the ACELA authorizes funding for up to 10 CCS demonstration projects through a competitive selection process[27] and the ACES Act and the APA would establish a CCS fund to finance either the first five[28] or the first 10 GW[29] of commercial-scale demonstration projects.[30]

Beyond these bills, several different amendments and legislative proposals have been introduced over the past few years supporting CCS development and deployment. In March 2011, Senator Bingaman introduced a CCS bill, S.699, entitled the "Department of Energy Carbon Capture and Sequestration Program Amendments of 2011." The bill authorizes the DOE to set up agreements providing technical and financial support for up to ten large-scale CCS projects. Additionally, the bill provides liability protection and federal indemnification for up to $10 billion. This bill is similar to one introduced by Bingaman in 2009, and is expected to face a number of obstacles due to lingering tension over budget issues and the EPA's GHG regulations. To name a few other examples - Senators Rockefeller and Voinovich introduced legislation in March 2010 to promote research and create incentives to develop and deploy full scale CCS. Congressman Boucher introduced legislation in 2009 to establish a $1 billion annual fund, derived from fees on the generation of electricity from coal, oil and natural gas, to provide grants to large-scale projects advancing the commercial availability of CCS technology. Senator Boxer introduced an amendment in 2008 to the Lieberman-Warner Climate Security Act establishing a long-term incentives and legal framework for CCS.

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[26] Congressional Research Service, 2010, Memorandum on Comparison of Selected Senate Energy and Climate Change Proposals, July 16, 2010, Washington, DC.
[27] S. 1462/ACELA would authorize funding for the DOE to support up to 10 CCS demonstration projects for large-scale integrated capture and sequestration of CO_2 from industrial sources (including power plants).
[28] H.R. 2454/Waxman-Markey would authorize financial support to at least five commercial-scale CCS demonstration projects, pending approval by the States.
[29] APA/Kerry-Lieberman would authorize a special funding program to support CCS projects that result in the capture of CO_2 emissions from at least 10 GW and would only be available for fossil-fueled electric generation projects of at least 100 MW, with at least 80 percent of funds awarded going to projects of at least 300 MW.
[30] The proposed CCS fund would be financed through a charge to electric utilities burning fossil fuels based on the carbon content of each fuel. This charge would be highest for coal and lowest for natural gas.

As the possibility for passage of a comprehensive climate change bill now seems unlikely in the near future, focus has turned towards bills with a more specific legislative focus. President Obama has announced a plan for a federal Clean Energy Standard (CES), similar in many aspects to the Renewable Portfolio Standards (RPS) now found in the majority of states. Senator Bingaman released a white paper in March 2011 seeking feedback on design elements for federal CEPS. Coal plants with CCS will likely be eligible under any federal standard if passed. The President's proposal also seeks to include efficient natural gas with CCS as well.

Additionally, there are a number of state initiatives and policies already in place to advance CCS. States are supporting research and development activities, developing regulatory frameworks, and providing incentives for CCS deployment. For example, several state universities are studying and assessing the potential for CCS. Some states have created task forces or directed state agencies or energy commissions to assess potential storage sites (both onshore and offshore) and develop reports with recommendations to accelerate CCS and address barriers to CCS.[31] In some cases, grant programs and trust funds have been used to support CCS research and development.[32] To address legal and regulatory barriers, some states have developed legislation to define jurisdiction for CO_2 injection,[33] designed regulations for injection wells,[34,35] established rules for permitting storage sites and CO_2 pipelines,[36] provided eminent domain powers for CCS development,[37] and developed laws related to liability[38] and property rights.[39]

An example of a regional group promoting clean coal and CCS is the Southern States Energy Board.[40] This group is a non-profit organization created in 1960 with the objective of enhancing economic development in the southern U.S. It includes sixteen southern states and two territories. They sponsor Southeast Regional Carbon Sequestration Partnership (SECARB), which assesses and evaluates the potential for CCS in the region.

[31] See, for example, California AB 1925, 2006., Colorado HB 06-1322, 2006; Illinois HB 3854, 2009; Massachusetts HB 5018, 2008; Minnesota SF 2096, 2007; Oklahoma SB 1765, 2008 and SB 679, 2009; Texas SB 1387, 2009; Texas HB 1796, 2009; Pennsylvania HB 2200, 2008; and West Virginia HB 2860, 2009.
[32] See, for example: Illinois SB 1592, 2007; Louisiana HB 661, 2009; Massachusetts HB 5018, 2008; North Dakota SB 2095, 2009; and Texas HB 1796, 2009.
[33] Oklahoma SB 610, 2009 and Texas HB 1796, 2009.
[34] Kansas HB 2419, 2007; Washington Administrative Code 173-218-115; and West Virginia HB 2860, 2009; Wyoming HB 90, 2008.
[35] West Virginia HB 2860, 2009; Wyoming HB 90, 2008.
[36] West Virginia HB 2860, 2009; Wyoming HB 90, 2008; Utah Senate Bill 202, 2008; Indiana Code 8-1-22.5, 2009; South Dakota HB 1129; a HB 661, 2009; and Montana HB 24, 2007.
[37] Louisiana HB 661, 2009.
[38] North Dakota SB 2095, 2009; Illinois HB 1704, 2007; Louisiana HB 661, 2009; New Mexico Executive Order 2006-069; Utah SB 202; Wyoming HB 58; Kentucky HB 491; Michigan SB 775; New York AB 5836; Pennsylvania HB 80 2009; and Montana SB 498, 2009.
[39] Oklahoma SB 610, 2009; North Dakota SB 2139; Montana SB 498; Louisiana SB 1117; Texas HB 149; West Virginia SB 2860; Wyoming HB 57, 58, 80, 89, and 90; Michigan SB 775; New Mexico SB 145; and New York AB 5836 and 8802.
[40] Southern States Energy Board http://www.sseb.org/secarb.php

Several states are providing incentives for CCS deployment such as portfolio standards that include generation of electricity from power plants with CCS, alternative fuel standards, emission standards, prioritization of CCS during power plant permitting processes, tax incentives (including tax exemption, reduced sales tax, taxation at lowered market value, tax credits), and provision of full or partial cost recovery through authorized rate changes for power plants with CCS. There are also regional partnerships formed to address climate change which also include a focus on CCS - the Midwestern Energy Security and Climate Stewardship Platform, the Regional Greenhouse Gas Initiative (RGGI), the Western Climate Initiative (WCI), and the Western Governors' Association (WGA) Clean and Diversified Energy Initiative. These initiatives are primarily focused on on-shore storage, rather than offshore.

In 2010, the EPA also finalized a couple of regulations related to CCS[41] that may help allay public concerns over the risks of such projects and also allow the EPA to collect better information on the CO_2 emissions associated with certain CCS projects. One of the regulations focuses on geologic sequestration and contains provisions regarding a new class of wells. These requirements were developed under the Safe Drinking Water Act's Underground Injection Control (UIC) program and are aimed at preventing groundwater pollution of drinking water. Additionally, the EPA finalized GHG reporting requirements under Mandatory Reporting GHG Rule subparts UU and RR for facilities that inject CO_2 underground. This will allow the EPA to track the amount of CO_2 received for underground injection and (for permanent storage sites covered by subpart RR) how much remains stored. (See section 6.2 of this report for more details.)

The UIC program does not apply to the OCS since the SDWA jurisdiction does not extend to the OCS. However, UIC Class VI requirements may apply on the OCS if a drinking water aquifer extends from the state-owned submerged lands into the OCS. Offshore geologic storage sites also would have to comply with subpart RR which requires a comprehensive monitoring plan that EPA would have to approve. It should be mentioned that the Class VI requirements do not apply to the DOE carbon storage demonstration sites that are being carried out around the country. These demonstration projects are small scale projects designed to test the feasibility of geologic storage.

4.3 Projections of CCS Deployment in the U.S.

The Energy Information Administration has provided analysis on a number of federal climate change bills and has found that most GHG reductions in the electricity-sector are achieved by reducing the role of conventional coal-fired generation and in part by increasing low-carbon technologies currently under development such as CCS.

[41] EPA, Geologic Sequestration of Carbon Dioxide, http://water.epa.gov/type/groundwater/uic/wells_sequestration.cfm and also http://yosemite.epa.gov/opa/admpress.nsf/e77fdd4f5afd88a3852576b3005a604f/2300005fbc11568d852577e3006058bd!OpenDocument.

Table 9 shows a summary of various projections made of the need for CO_2 geologic sequestration in the U.S. under a variety of legislative and other scenarios. Since there have not been any recent major climate change bills, most of the information provided below draws on an earlier report for the Interstate Natural Gas Association of America (INGAA) Foundation.[42] **Table 9** has been updated with EIA's analysis[43] of the Kerry-Lieberman American Power Act, proposed in 2010, and the Waxman-Markey bill that passed the House in 2009. EIA projections of legislative proposals typically go through 2030 or 2035. Quantities are shown in megatonnes per year.

The first projection in **Table 9** is NETL's "Accelerated CCS Technology Case," which is a conceptual planning scenario based on an assumption of an accelerated pace of CCS demonstration projects funded by DOE and other sources.[44] This case has the highest level of CCS in the early years, but is near the middle of the scenarios in the later years.

The next eleven projections shown in **Table 9** are EIA projections prepared for Congress of the impact of various legislative proposals as estimated by the NEMS model, the forecasting system used to prepare the Annual Energy Outlook.[45,46] EIA usually ran several NEMS analyses of each GHG proposal by varying assumptions related to the availability of international offsets, the availability of alternatives such as nuclear power and the cost of new power plant technologies. **Table 9** shows the highest and lowest levels of CCS forecasted among those NEMS analyses. For the Lieberman-Warner proposal, EIA ran two cases in which CCS was assumed not to be available and so the CCS projection was zero. Those zero-CCS cases are not included in the row labeled "Lieberman-Warner Lowest".

The next two cases in **Table 9** are from a report prepared by ICF for the American Petroleum Institute (API).[47] Those scenarios are based on allowance prices expected under GHG constraints similar to those in the McCain-Lieberman and the Bingaman-Specter bills. The analysis looked only at the expected effect of the allowance prices on CCS and did not consider the financial incentives in the bills for CCS. This is why the API report's expectations for CCS volumes are lower than those projected by EIA.

[42] ICF International, "Developing a Pipeline Infrastructure for CO_2 Capture and Storage: Issues and Challenges," Prepared for the INGAA Foundation, February 2009.
[43] EIA analysis on legislative proposals can be accessed at: http://www.eia.gov/oiaf/service_rpts.htm.
[44] NETL presentation to GHGT-8 Conference in Trondheim Norway.
[45] EIA, 2008, "Energy Market and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007," EIA Report SR/OAIF/2008-01, April 2008.
[46] . EIA, 2007, "Energy Market and Economic Impacts of S. 280, the Climate Stewardship and Innovation Act of 2007," EIA Report SR/OAIF/2007-04, July, 2007.
[47] ICF International, "Impact of Mandatory GHG Control Legislation on the Refining and Upstream Segments of the U.S. Petroleum Industry," January 2008.

Table 9 Projections of CCS Deployment in the U.S. (megatonnes per year)

	2012	2015	2020	2025	2030
DOE NETL Accelerated CCS	50	0	200	0	650
EIA Kerry-Lieberman Lowest	0	0	192	237	287
EPA Kerry-Lieberman Lowest	0	0	0	0	0
EIA Kerry-Lieberman Highest	0	18	138	313	629
EIA Waxman-Markey Lowest	0	0	45	109	201
EIA Waxman-Markey Highest	0	0	152	377	402
EIA Bingaman-Specter Lowest	0	0	23	87	246
EIA Bingaman-Specter Highest	0	20	251	998	1511
EIA McCain-Lieberman Lowest	0	50	150	350	600
EIA McCain-Lieberman Highest	0	200	450	700	900
EIA Lieberman-Warner Lowest (Excludes cases in which CCS is not allowed)	15	40	85	174	226
EIA Lieberman-Warner Highest	28	49	147	290	386
API Bingaman-Specter-like allowance pricing	0	0	0	7	31
API McCain-Lieberman-like allowance pricing	3	18	87	278	653
IPM 4P Multi-client Case	0	0	0	93	437
IPM Stringent Multi-client Case	0	0	112	441	1243
NGC NEMS Analysis "Modest Case" of McCain-Lieberman	0	34	201	487	1031
Average	6	29	140	329	590
Median	0	18	142	290	519
US Low Case	0	3	25	100	300
US High Case	5	50	150	500	1,000

The next two cases are the projection made with ICF's IPM® model of the electric power sector. The IPM® 4P (ICF's expected base case that includes a carbon policy, in addition to the three regulated pollutants – SOx, NOx, Hg) and the Stringent cases represent two alternative levels of GHG control as analyzed in ICF's Multi-client Fuels report in the Fall of 2007. The 4P case resulted in allowance prices of $32 per ton in 2030 while the Stringent Case has allowance prices of $61 per ton. ICF's latest projections have CCS deployment at close to zero until after 2030 due in part to the current legislative outlook, with no legislative climate change bill being modeled.

The final projection appearing in **Table 9** is the result of National Energy Modeling System (NEMS) model runs for members of the Natural Gas Council (NGC) to analyze the McCain-Lieberman bill.[48] This run differed from those made by EIA in that it restricted the availability of nuclear power and renewable power generation and assumed less elastic supplies of natural gas. This created a case in which the reliance on CCS for coal and natural gas power plants was greater than that seen in the EIA cases of the same bill.

There is a wide range of CCS volumes anticipated among these various projections. They help illustrate the wide ranging impacts of the key factors discussed earlier in this chapter including the legal framework for GHG controls, the legal framework for CCS, level of GHG caps, availability and usability of international and domestic offsets, cost of technologies, financial incentives for CCS and ability to build new nuclear and renewable power plants. To determine the amount of CO_2 reductions associated with projected CCS development under various climate change proposals, the Low and High Cases shown at the bottom of **Table 9** were adopted for this analysis. The High Case anticipates 1,000 megatonnes of CCS by 2030 while the Low Case has 300 megatonnes by that date. These numbers can be compared against U.S. CO_2 emissions from coal power plants which are roughly 2,000 megatonnes per year. As a result, the High Case and Low Cases are roughly equivalent to having 50 percent and 15 percent respectively of the existing coal fleet capacity be operated with CCS by 2030.

4.4 Summary

There is a lot of discussion on the role of CCS in helping mitigate climate change and a number of initiatives have been developed to help enhance the deployment of CCS. However, there have not been a lot of recent quantitative projections on GHG reductions expected to be achieved through CCS, especially with the recent lack of a support for a federal climate change bill, and there is little analysis available of CCS deployment in later years (2030-on). EPA analysis does extend to later years but does not quantify the expected GHG reductions from CCS. For example, the American Clean Energy Security Act (Waxman-Markey) and the American Power Act (Kerry-Lieberman) estimated that around 30% of fossil-fuel-based electricity

[48] Natural Gas Council, 2008, "Summary of Natural Gas Council's Analysis of Lieberman-Warner Climate Regulation Bill (S. 3036)," June 2, 2008.

generation would come from power plants with CCS by 2040, rising to around 59 percent by 2050 (15 and 16 percent respectively of total electricity generation).[49]

To conclude, despite a number of federal initiatives spearheaded by DOE and EPA and state and regional programs, the lack of any comprehensive federal climate change bill and lessened support of regional programs negatively impacts the pace of expected CCS deployment. Certain policies like California's cap-and-trade program, federal investment in RD&D, a federal CES, and then state and regional programs have the potential to partially offset the lack of a comprehensive federal plan.

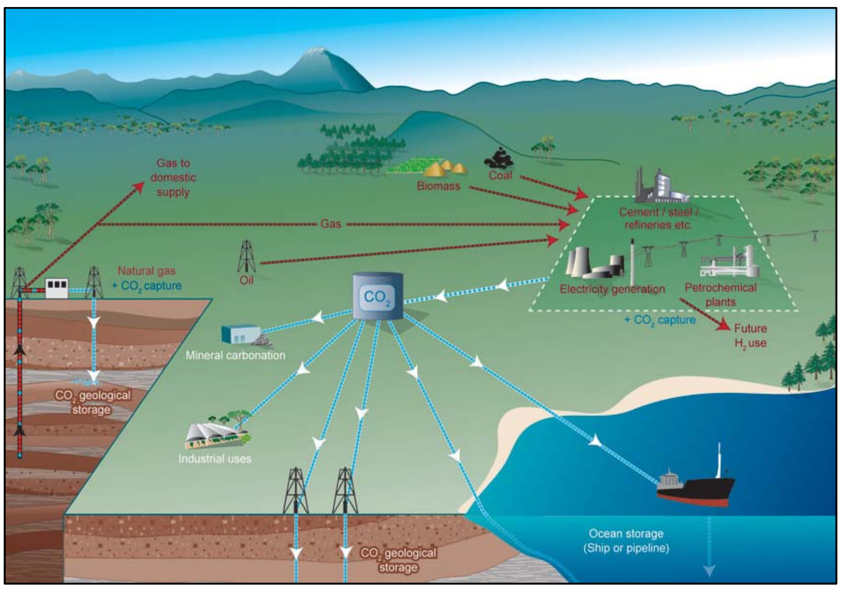
[49] EPA, 2008, Report of the Interagency Task Force on Carbon Capture and Storage, available at: http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf.

5. Technologies and Costs of Capture, Transport, and Storage

5.1 Introduction

In the past decade or so, there has been a significant amount of research and development on Carbon Capture and Storage (CCS) technologies as a possible solution for making deep reductions in CO_2 emissions from power plants and other industrial facilities. CCS technology involves three main steps: a) capture and compression of CO_2 from a power plant or other industrial facility, b) transporting the captured CO_2 to a storage site, and c) injecting and safely storing the CO_2 in underground geological reservoirs. **Figure 17** illustrates the overall technological components of CCS.

Figure 17 Illustration of CCS Components



Source: IPCC, 2005.

CCS technology contains a number of process components that are well understood (pipeline, compression, etc.). However, approximately 80% of the cost of CCS lies in capturing the CO_2, and capture technologies are the subject of significant research and development (R&D).[50,51,52] Beyond the high cost of CO_2 capture, there also is

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[50] IPCC, 2005, IPCC Special Report on Carbon Dioxide Capture and Storage: Technical Summary.
[51] Global CCS Institute and ICF International, 2010, Defining CCS Ready: An Approach to An International Definition, Canberra, Australia, Global CCS Institute.
[52] National Coal Council, 2008, "Advanced Coal Technologies: Greater Efficiency and Lower CO_2 Emissions," http://www.nationalcoalcouncil.org/Documents/Advanced_Coal_Technologies.pdf.

significant risk in the geological storage and appropriate selection and characterization of storage sites.

In this chapter, the capture, transport and storage aspects of the CCS technologies will be described, along with highlights on how the regulatory and policy intersects with CCS technology development and deployment.

5.2 Capture

Capture of carbon dioxide from flue gases (and other gas streams) is not new. It has been used in industrial processes for over 80 years, although most of the captured CO_2 is simply vented to the atmosphere.[53] Currently, CO_2 capture technologies are used for natural gas purification, production of hydrogen-rich syngas for manufacture of ammonia and methanol, and carbonation of beverages and other food processing.

The CO_2 capture technologies are the same regardless of whether the captured CO_2 is stored onshore or in the OCS. There are three major categories of technologies used for capturing CO_2: **post-combustion capture, oxyfuel combustion, and pre-combustion capture**. In a post-combustion capture system the CO_2 is captured from the flue gas only after the fuel (with carbon) is combusted into CO_2—i.e., post-combustion. The flue gas has low concentrations of CO_2 (given that most of the flue gas is composed of nitrogen from air, which is used as the oxidant). In oxyfuel combustion, pure oxygen and recycled CO_2 are used for combustion rather than air, which increases the CO_2 concentration in the flue gas (after dehydration). In contrast, in a pre-combustion system, the CO_2 is removed (from gasified coal or natural gas) before combustion.

Post-combustion capture

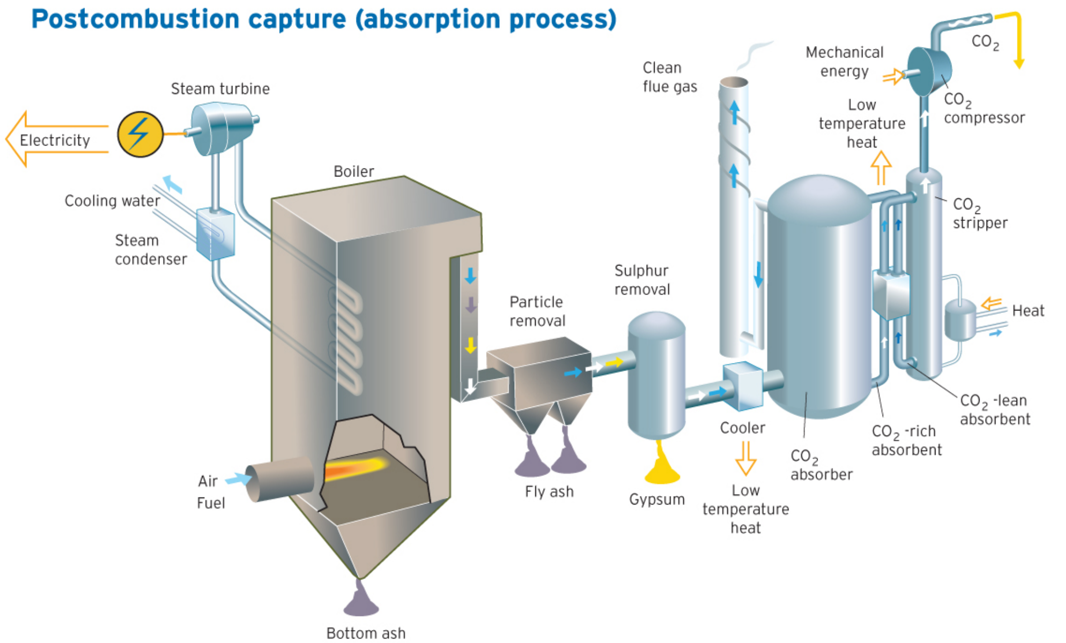
In order to remove the CO_2 from the flue gas, the flue gas is brought in contact with an absorbent solvent (e.g., amine) such that the CO_2 binds with the solvent at temperatures of 40 to 60 degrees Celsius (see **Figure 18**). The flue gas, now separated from most of its CO_2, is sent to the stack and released to the atmosphere. The "CO_2-rich solvent" is pumped into a regeneration vessel (or stripper), where the CO_2 is stripped from the solvent under higher temperatures ranging from 100 to 140 degrees Celsius. The "*lean"* solvent is then cooled and pumped back to the absorption tower through a heat exchanger to be reused in the process.

The heat supplied to the regeneration vessel carries a significant energy cost that may reduce a plant's power output by 20 to 40 percent.[54] The CO_2 is then cooled, dried, and compressed to a supercritical fluid state at which point it can be transported for storage or used commercially.[55] Any impurities, such as SO_X and NO_X, in the flue gas need to be removed prior to the post-combustion capture

[53] IPCC, 2005, IPCC Special Report on Carbon Dioxide Capture and Storage: Technical Summary.
[54] NETL, 2008, Existing Coal Power Plants and Climate Change: CO_2 Retrofit Possibilities and Implications.
[55] National Coal Council, 2008, Advanced coal technologies: Greater efficiency and lower CO_2 emissions.

process, in order to achieve the longevity requirements of acid gas removal and amine solvents.[56]

Figure 18 Post-Combustion Capture Process (Absorption)



Source: Vattenfall, 2010[57]

The absorbent solvents for post-combustion capture that are currently under consideration include amine, chilled ammonia, and carbonates. Absorbent solvents based on amines, such as mono-ethanol amine (MEA), are commercially proven,[58] and they can remove substantial amounts of CO_2 at low pressure and are relatively inexpensive. An amine scrubbing system is capable of removing between 80% and 95% of the CO_2 from a flue gas stream. However, they are corrosive, have high degradation in the presence of oxygen and acid gases, have high solvent losses due to fast evaporation, and require a significant amount of energy for regeneration.[59] Furthermore, NO_x and SO_x react with the amine, resulting in a reduction in solvent performance, higher chemical consumption, and poor economic performance.

[56] Tzimas, E., A. Mercier, et al., 2007, Trade-off in emissions of acid gas pollutants and of carbon dioxide in fossil fuel power plants with carbon capture, Energy Policy 35: 3991–3998.
[57] Vattenfall, 2010, *Illustrations,* Retrieved from Vattenfall News & Reports website, http://www.vattenfall.com/en/ccs/illustrations.htm.
[58] The amine-based chemical absorption process for CO_2 capture is widely used in the beverage and petrochemicals industries, and consequently commercial amine absorption systems are available from a number of vendors.
[59] Zachary, J., 2008, "CO_2 Capture and Sequestration Options - Impact on Turbomachinery Design," Bechtel Power Corporation.

Hence, as mentioned earlier, acidic gases such as NO_x and SO_x must be removed from the flue gas prior to passing through the absorber tower.

Chilled ammonia-based CO_2 capture is considered a key technology that could compete with amine-based capture. Although still under development, the chilled ammonia-based CO_2 capture process has a strongly reduced efficiency penalty due to lower heat of reaction for the ammonia-CO_2 reactions, higher solubility of CO_2 in the low temperature ammonia solvent, regeneration at only moderately higher temperature (without the need for stripping steam), and lower ammonia emissions.[60] Chilled ammonia also has higher tolerance to acid gases such as SO_x and NO_x, and hence the flue gas need not be purified as much as for amine-based capture. However, there are barriers, at present, for large-scale demonstration of ammonia-based capture, including: ammonia losses as vapor phase (which is often not allowed in many jurisdictions); high refrigeration load requirements; lack of technology maturity and confidence; and increased capital costs due to the need for several absorber vessels used for minimizing loss of ammonia and maintaining water balance.

Beyond chilled ammonia, there are development efforts on novel solvents for improved performance with reduced auxiliary energy consumption, as well as new process designs such as hybrid membrane-absorbent systems, solid adsorbents, and high temperature regenerable sorbents.[61] One promising option to reduce the efficiency penalty is CaO looping.[62] In this process, CaO reacts with CO_2 to form $CaCO_3$ at approximately 600°C. This calcium carbonate can be regenerated at temperatures of approximately 900°C. Weak points are the energy penalty of flue gas reheating and sorbent regeneration and the low stability of the CaO sorbent, leading to a large make-up flow of sorbent.

While still in the research and development stage, these new technologies may, in the future, lead to post-combustion capture systems that have lower energy and efficiency penalties. A key challenge will be to prove their reliability at commercial-scale operation.

Oxyfuel Combustion Capture

Standard combustion uses air (with 21% oxygen) as the oxidizing agent; however, fuel can also be combusted using pure oxygen instead of air. Such "oxyfuel combustion" can be used in coal-based power plant technologies, in natural gas-based power plants, and in other industrial facilities. Oxyfuel combustion technology can also be retrofitted on existing pulverized coal or fluidized bed combustion power

[60] McCullough, M., D. Duellman, et al., 2009, Update on CO_2 Capture & Storage Project at AEP's Mountaineer Plant (Presentation to USEA), Washington, DC.
[61] IPCC, 2005, IPCC Special Report on Carbon Dioxide Capture and Storage: Technical Summary.
[62] Abanades, J. C., 2002, "The Maximum Capture Efficiency of CO_2 Using a Carbonation/Calcination Cycle of CaO/CaCO3," Chemical Engineering Journal 90: 303-306.

plants.[63] Combustion using pure oxygen, however, leads to very high temperatures that cannot be handled by standard boiler material. Thus, in practical terms, oxyfuel combustion refers to technology where fuel is burned with a mixture of oxygen and recycled flue gas (with mainly CO_2) to maintain similar oxygen proportion as air-blown boilers (see **Figure 19**).

The flue gas consists of mainly CO_2 and water vapor, once water from the flue gas is removed as the gas is cooled and condensed. The flue gas is then purified further depending on the requirements of the purity of the CO2 stream. Ingress of air from parts of the boilers and other equipment may introduce sufficient nitrogen such that additional purification of the CO_2 stream may be required. By eliminating nitrogen flow, the flue gas volume in an oxyfuel power plant can be reduced by 70 percent, compared to standard power plant, with CO_2 concentrations between 80-98% after extracting the water out of the flue gas.[64,65] Such high CO_2 concentration in the flue gas can be a significant advantage for CO_2 capture.

The reduced flue gas volume also results in overall smaller equipment, including a smaller overall size of the boiler and a simpler flue-gas purification scheme, which can reduce capital and operating costs[66]—although they are offset by the high cost of producing oxygen in the first place The elimination of nitrogen and oxygen-enrichment in the boiler significantly reduces the production of NO_x, and in many cases, eliminates the need for separate NO_x cleanup systems from the flue gas.[67] Furthermore, SO_x and NO_x can also be removed from the CO_2 stream during the O_2 compression and condensation stages as well.[68] Additionally, mercury emissions are reduced and NO_x emissions are estimated to be cut in half.[69]

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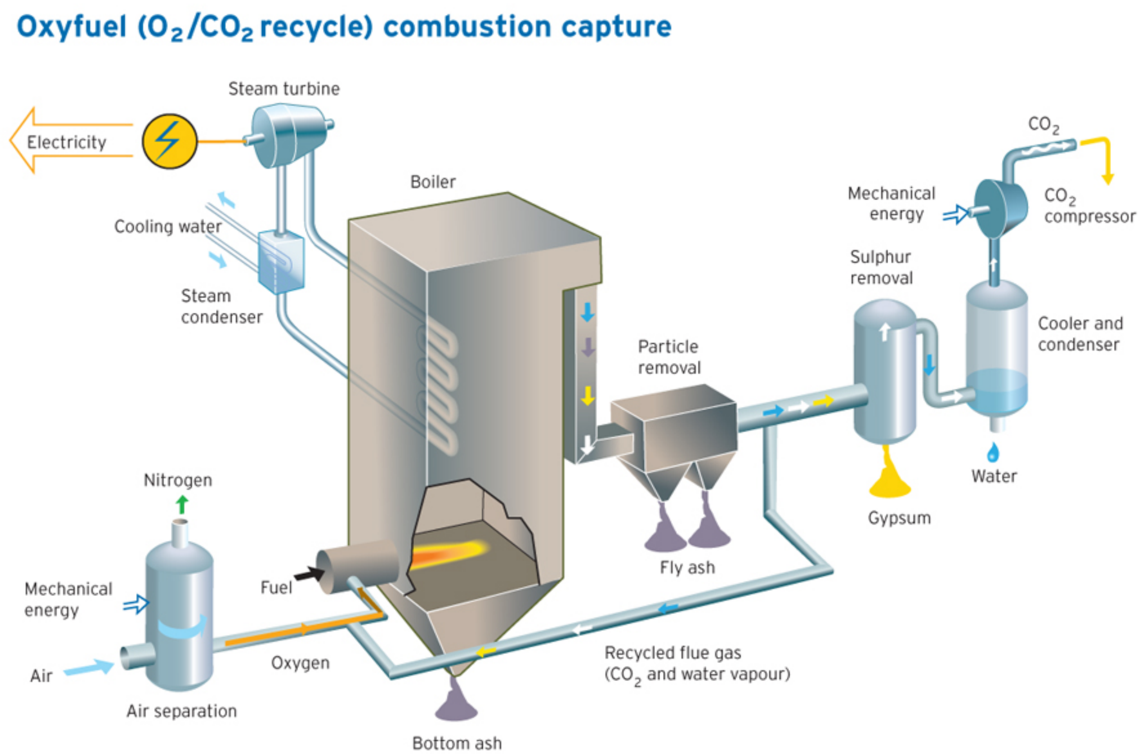
[63] Marion, J. L., C. R. Bozzuto, et al., 2003, Greenhouse Gas Emissions Control By Oxygen Firing In Circulating Fluidized Bed Boilers: Phase 1 -- A Preliminary Systems Evaluation, Alstom Power Inc. and U.S. D.O.E. NETL.

[64] Farzan, H., S. J. Vecci, et al., 2005, Pilot-Scale Evaluation of Coal Combustion in an Oxygen-Enriched Recycled Flue Gas, The 22nd International Pittsburgh Coal Conference, Pittsburgh, PA.
[65] IPCC, 2005, IPCC Special Report on Carbon Dioxide Capture and Storage: Technical Summary.
[66] *Ibid*.
[67] Farzan, H., S. J. Vecci, et al., 2005, Pilot-Scale Evaluation of Coal Combustion in an Oxygen-Enriched Recycled Flue Gas, The 22nd International Pittsburgh Coal Conference, Pittsburgh, PA.
[68] Normann, F., K. Andersson, et al., 2009, "Emission control of nitrogen oxides in the oxy-fuel process," Progress in Energy and Combustion Science 35(5): 385-397.
[69] Zachary, J., 2008, CO_2 capture and sequestration options - impact on turbomachinery design, Bechtel Power Corporation.

Figure 19 Oxyfuel Combustion CO_2 Capture



Source: Vattenfall, 2010[70]

A key disadvantage for oxyfuel combustion is the high volume of pure oxygen needed for combustion. The standard technology for air separation is based on cryogenic techniques, which consumes a lot of power.[71] Hence, oxyfuel-based technologies are likely to become relevant and competitive with standard combustion and gasification technologies (see below) if CCS becomes an essential part of operating power plants. Cost estimates for new power plants indicate that oxyfuel and carbon capture for a new PC power plant results in a 50 percent increase in the specific capital cost compared to a plant without capture; similarly, a 90 percent cost increase results for oxyfuel fluidized bed power plant with carbon capture [72,73]

As with power plants, industrial boilers and process heaters could be run using oxygen instead of air to produce a flue gas with little nitrogen. The CO_2 is separated

[70] Vattenfall, 2010, *Illustrations,* Retrieved from Vattenfall News & Reports website, http://www.vattenfall.com/en/ccs/illustrations.htm.
[71] IPCC, 2005, IPCC Special Report on Carbon Dioxide Capture and Storage: Technical Summary.
[72] Marion, J. L., C. R. Bozzuto, et al., 2003, Greenhouse Gas Emissions Control By Oxygen Firing In Circulating Fluidized Bed Boilers: Phase 1 -- A preliminary systems evaluation, Alstom Power Inc. and U.S. D.O.E. NETL.
[73] Dillon, D. J., R. S. Panesar, et al., 2004, Oxy-Combustion Processes For CO_2 Capture from Advanced Supercritical PF and NGCC Power Plant, 7th International Conference on Greenhouse Gas Control Technologies (GHGT-7), Vancouver, Canada.

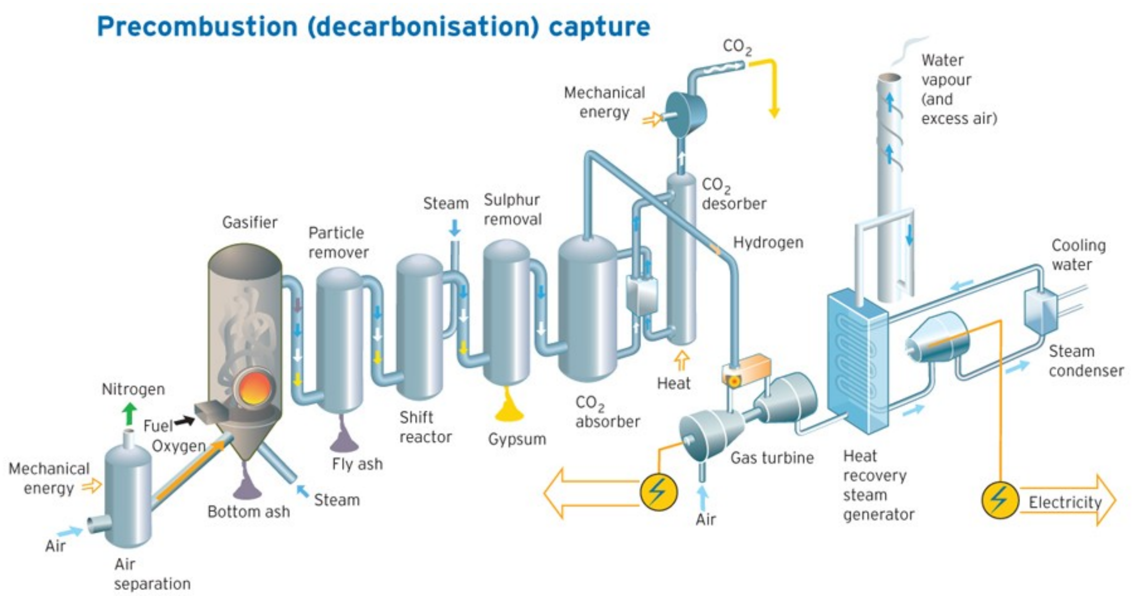
from water vapor by condensing the water through cooling and compression. Similar to the power plants, further treatment of the flue gas may be needed to remove pollutants and non-condensable gases (such as nitrogen and argon) prior to CO_2 storage. The economics of oxy-firing (vs. other options) for industrial facilities depend on the economies of scale that can be achieved in air separation, the duct work and blowers needed for moving oxygen and the recirculated flue gases, the purity requirements of the final CO_2 stream, and the cost of energy used for air separation.

While the technology's potential for carbon capture is quite promising, it is only at the early demonstration stage. Pilot-scale demonstration plants are being planned in Europe, Australia and Canada. It is expected that with advanced air separation technologies using high-temperature oxygen-ion transport membranes (made of ceramics from a mixture of various metal oxides) will reduce air separation costs – making oxyfuel combustion more competitive with other technologies for carbon capture.[74] Other advanced techniques such as Vacuum Swing Adsorption (VSA), Pressure Swing Adsorption (PSA), oxygen selective membranes, and chemical looping combustion are also being explored. These advanced technologies enhance the future prospects for oxyfuel combustion.

[74] Gupta, M., K. E. Zanganeh, et al., 2005, Oxy-fuel Combustion With and Without Carbon Capture: A Techno-Economic Assessment and Future Prospects, 22nd International Pittsburgh Coal Conference, Pittsburgh, PA.

INTERNATIONAL

Figure 20 Pre-Combustion Capture Process Using a Sour Shift



Source: Vattenfall, 2010 [75]

Pre-combustion capture

For 'pre-combustion capture', such as in an Integrated Gasification Combined Cycle (IGCC) or a natural gas power plant, the capture of CO_2 occurs before combustion. In a standard IGCC process without carbon capture, solid fuel is pyrolyzed and partially oxidized using oxygen (or air) and steam to produce a high-energy gas – usually referred to as synthetic gas or syngas. To produce electricity, the syngas, which is composed primarily of carbon monoxide (CO) and hydrogen (H_2), is produced under pressure, water-cooled, cleaned, and burned in a gas turbine (**Figure 20).** The steam produced from the heat exchanger, which is used for cooling the syngas, is used to produce power with an integrated steam turbine in combined cycle operation. In addition to the steam cycle integration, compressed air (obtained from a compressor running off the gas turbine shaft) can also be integrated with the air separation unit that produces the required oxygen. In effect, IGCC is a hybrid between the traditional coal-combustion-powered steam-based electricity generation and the natural-gas-based combined cycle electricity generation.[76]

For capturing CO_2, the syngas, which is removed of particulates and possibly sulfur, is introduced into a water-gas shift reaction that converts the CO to CO_2. The high concentration of CO_2 from the syngas is then removed using solvents, and the hydrogen-rich fuel gas is sent to the combined cycle turbine. Solvent technologies, such as Selexol or Rectisol, are typically used for CO_2 removal, and they can also be

[75] Vattenfall, 2010, *Illustrations,* Retrieved from Vattenfall News & Reports website, http://www.vattenfall.com/en/ccs/illustrations.htm.
[76] Chikkatur, Chaudary, and Sagar, 2011, Coal Power Impacts, Technology & Policy: Connecting the Dots, Annual Review of Environment and Resources 36 (2011): 101-138.

used for desulphurization. The resulting hydrogen-rich fuel stream cannot be fired in a gas turbine equipped with dry low-NO_x combustion chambers due to the wide flammability limits and high flame speed of hydrogen. Therefore, diffusion flame combustion chambers are needed. In addition, the hydrogen-rich fuel stream needs to be humidified and nitrogen needs to be added (as is also done in IGCCs without CO_2 capture) to reduce NO_x formation.

An important consideration with pre-combustion CO_2 capture is whether to remove sulfur compounds before or after water shifting. If removed before, it is called "sweet shift" (or clean shift). An advantage of the sweet shift is that it is easier to remove a relatively pure sulfur (H_2S) flow without dilution by CO_2. If sulfur compounds are removed after shift, the setup is called "sour shift." Advantages of this arrangement are a more level temperature profile, and thus higher efficiency. Also, a separate carbonyl sulfide hydrolysis reactor is no longer needed as this reaction already takes place in the shift reactors. Moreover, sour shift catalysts have a wider temperature window to operate in than sweet shift catalysts. Avoiding sulfur removal before shifting leaves more steam in the syngas flow, requiring less additional steam for shifting. Natural-gas-fired combined cycle power plants can also be equipped with pre-combustion capture.

For these gaseous fuels, the fuel conversion into syngas is achieved through partial oxidation and/or steam reforming. If a combination of both is used, it is generally termed auto thermal reforming. As natural gas is a clean fuel, no elaborate cleaning is required, but humidifying and possibly steam or water injection in the combustion chamber may still be required to reduce NO_x formation.

One drawback of pre-combustion capture is that there are only a small number of IGCC plants, while the industry has much more experience in pulverized coal plants. In recent years, however, many coal gasifiers have been built for chemicals production, and the reliability of IGCC plants currently running (such as Nuon's Willem Alexander Centrale in Buggenum, The Netherlands) matches that of pulverized coal plants.

There are a large number of potential improvements for the pre-combustion capture systems. Research is focused on both improving the IGCC process itself as well as improving CO_2 separation technologies. IGCC technology is still in the development phase, with little commercial operation experience. Therefore, there is a significant potential for major performance improvements and capital cost reductions. As both gasification and power island technologies are fairly mature, most efforts are focused on the development of integration components such as air separation, syngas cleanup, and advanced turbines for hydrogen-rich gas. Factors driving gasifier developments are focused on increasing availability and reliability and reducing the investment cost.

CO_2 Compression

In all three capture options, the captured CO_2 must be compressed and sent into a pipeline for transportation. This is typically done with electric powered centrifugal pumps. Inlet pressures at the pumps would be about 1,850 psi (12.8 MPa) and outlet pressures 2,200 psi (15.2 MPa).[77]

The cost of compression is typically included as part of the capture costs. The energy consumption for CO_2 compression is lower in pre-combustion capture than in post-combustion capture because some of the CO_2 leaves the separation unit at elevated pressure. Furthermore, compression of the flue gas stream can be used to remove some impurities from the CO_2 stream during the compression stages—which can be particularly relevant for oxyfuel combustion. The energy consumption for CO_2 compression in the oxy-fuel processes depends on the composition of the CO_2 stream (e.g., 75% by volume in the coal-fired plant and 93% by volume in the gas fired plant). Impurities can be cryogenically removed from the CO_2 during compression, to give a final CO_2 purity of 96% by volume. This approach can eliminate the use of flue gas desulfurization and selective catalytic reduction processes to remove SOX and NOX. The energy consumption of the cryogenic CO_2 separation unit used for purifying CO_2 streams from oxyfuel combustion is often included in the CO_2 compression power consumption.[78]

Cost of Capture

According to DOE analyses, the addition of currently available pre-combustion CO_2 capture and compression technology onto a new 550 MWe net output Integrated Gasification Combined Cycle (IGCC) power plant increases the capital cost by approximately $400 million (~25 percent) compared with the non-capture IGCC plant. For a similarly sized new supercritical pulverized coal (PC) plant, post-combustion and oxy-combustion capture would increase capital costs by approximately $900 million (80 percent) and $700 million (65 percent), respectively. Post-combustion CO_2 capture on a similarly sized new Natural Gas Combined Cycle (NGCC) plant would increase the capital cost by $340 million or 80 percent relative to a NGCC plant without capture. These costs include the cost of compressing the CO_2.

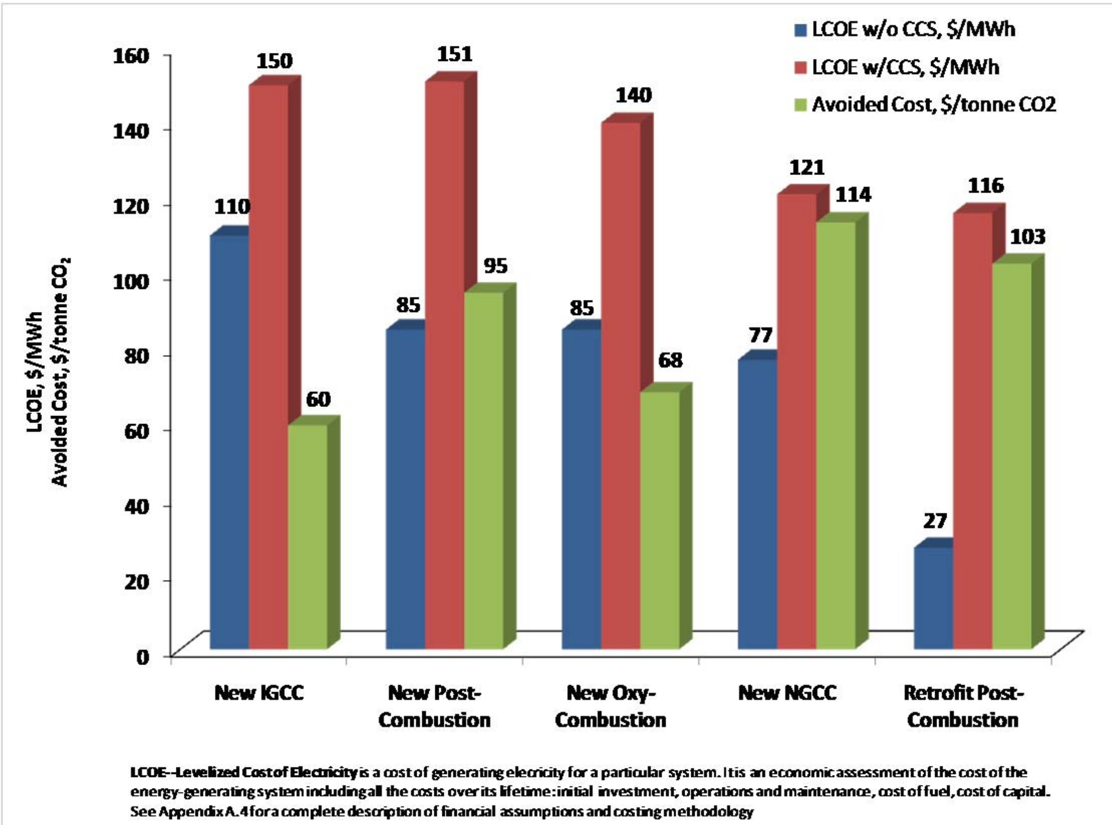
Figure 21 shows the range of these costs for various types of power plants.[79] In terms of <u>cost per tonne of CO_2 avoided</u>, values range from $60/tonne for IGCC to $114/tonne for NGCC. The <u>dollar per tonne of CO_2 avoided</u> is the incremental cost of CO_2 emissions avoided by applying CCS when compared to a similar non-captured facility. It is calculated by dividing the difference in cost of electricity (COE) by the difference in CO_2 emissions with and without CO_2 capture. The <u>dollar per tonne of CO_2 captured</u> is the incremental cost per tonne of CO_2 captured and is calculated by dividing the difference in COE, by the total CO_2 emissions captured. <u>The Levelized Cost of Electricity (LCOE)</u> shown in the chart is the cost of generating electricity for a particular system. It includes initial investment, operating costs, fuel costs, and cost of capital.

[77] ICF, 2008, Developing a Pipeline Infrastructure for CO_2 Capture and Storage: Issues and Challenges, INGAA Foundation.

[78] IPCC, 2005, IPCC Special Report on Carbon Dioxide Capture and Storage: Technical Summary.
[79] CCS Task Force, 2010, Report of the Interagency Task Force on Carbon Capture and Storage. Washington, D.C. http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf.

In terms of cost per tonne of CO_2 captured, values range from $49/tonne for IGCC to $95/tonne for NGCC. As discussed above, there are ongoing R&D and demonstration projects, however, for reducing the cost of capture and compression.

Figure 21 CCS Costs for Different Power Plants



Source: CCS Task Force 2010[80]

5.3 CO_2 Transportation

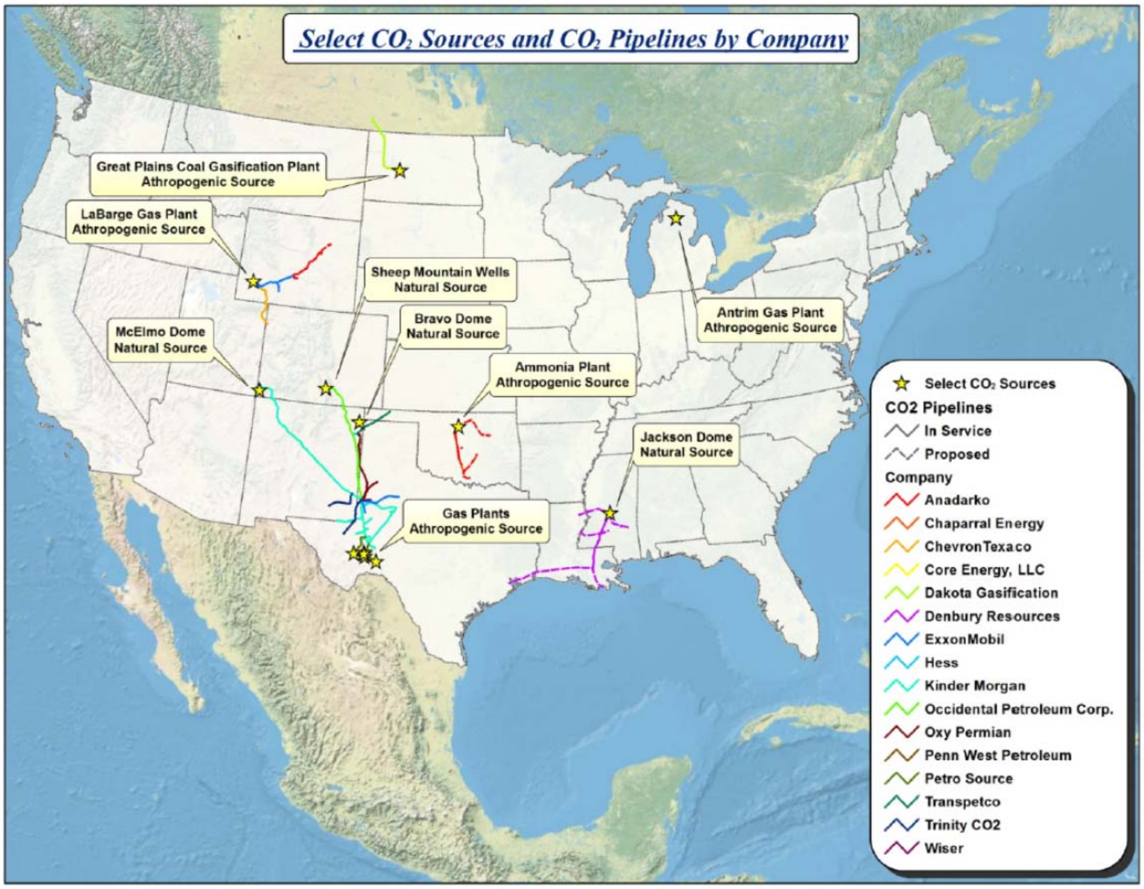
CO_2 pipelines are a mature technology and are the most common method for transporting large CO_2 volumes. Gaseous CO_2 is typically compressed to a pressure near 2,200 psi (15.2 MPa) in order to avoid two-phase flow regimes and increase the density of the CO_2, thereby making it easier and less costly to transport. CO_2 also can be transported as a liquid in ships, tank trucks, or rail tankers that carry chilled CO_2 in insulated tanks.

The first long-distance CO_2 pipeline came into operation in the early 1970s in the Permian Basin of West Texas, and there are over 3,600 miles of pipeline,

[80] CCS Task Force, 2010, Report of the Interagency Task Force on Carbon Capture and Storage, Washington, D.C. http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf.

transporting more than 40 megatonnes of CO_2 per year from natural and anthropogenic sources—see **Figure 22**. These existing pipelines operate in the liquid and supercritical CO_2 phases at ambient temperatures and high pressure. In most of these pipelines, pipelines have intermediate (booster) pumping stations to compensate for pressure drop along the pipeline.

Figure 22 Existing and Proposed CO_2 Pipelines



Source: 2010 CCS Task Force Report[81]

The design of a CO_2 pipeline is similar to that of a natural gas pipeline except that higher pressures must be accommodated; often with thicker pipe. The thicker pipes allow for low temperatures that may be associated with rapid pressure reduction or during the initial fill of the line.[82] Also, fracture propagation must be mitigated against when designing a CO_2 pipeline, as such fractures are more likely in CO_2 pipelines due to their slower decompression characteristics. Hence, their construction includes fracture arrestors every 1,000 feet to reduce fracture propagation. The

[81] CCS Task Force, 2010, Report of the Interagency Task Force on Carbon Capture and Storage, Washington, D.C. http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf.
[82] *Ibid*.

presence of impurities lowers the saturation pressure of the gases which affect the susceptibility of pipeline materials to arrest fractures—hence, the impact of impurities needs to be evaluated when designing a CO_2 pipeline. Valve materials must be compatible with CO_2, and CO_2-resistant elastomers are used around valves and other fittings. Unlike existing pipelines, the CO_2 pipeline for CCS will be moving a supercritical fluid that is compressed at the capture plant initially and then pumped into the pipeline. Only long distance pipeline would have additional booster stations.

Modeling of Future CO_2 Pipeline Network

In order to evaluate the costs of offshore CO_2 sequestration, it is necessary to model the distribution and characteristics of the CO_2 pipeline network that would connect stationary sources with both onshore and offshore sequestration sites.

In a 2009 study for the Interstate Natural Gas Association of America (INGAA) Foundation, ICF evaluated the potential configuration and scope of a future U.S. CO_2 pipeline network.[83] Prior to the study, little analytical work had been done to evaluate the likely future development of a CO_2 pipeline network and its cost. The study focused on the pipeline infrastructure requirements for CCS in compliance with mandatory greenhouse gas reductions. It concluded that by 2030, between 15,000 and 66,000 miles of pipeline would be required to transport CO_2, depending on how much CO_2 must be sequestered and the extent to which enhanced oil recovery is involved. The study also concluded that while there are no significant barriers to building this network, the major challenges will lie in the areas of public policy and regulation. Because a CCS infrastructure can develop in several ways, it was concluded that the government must address questions about industry structure, government support of early development, regulatory models, and operating rules.

The results of this analysis were used to help incorporate future CCS transportation and storage into the ICF IPM® model.

Cost of CO_2 Pipelines

The costs of building pipelines in the U.S. and Canada have been going up significantly in the last several years, due to higher material and labor costs. Costs can vary significantly from location to location based on the terrain, the density of development along the pipeline route and local construction costs. Since there are large economies of scale for pipelines, CO_2 transportation costs would depend on how many power plants and industrial CO_2 sources could share a pipeline over a given distance. The longer the distance from the source to the CO_2 sink, the more chance there is for other sources to share in the transportation costs. **Table 10** provides the cost of different sizes of CO_2 pipelines, along with some example cases of how different sources might use networked pipelines. The cost per unit transported in the table includes the cost of electricity in the electric-power booster pumps that would be located along the length of long pipelines.

[83] ICF International, 2009, "Developing a Pipeline Infrastructure for CO_2 Capture and Storage: Issues and Challenges," prepared for the INGAA Foundation, Washington, DC, February, 2009.

The costs shown on the table are representative of offshore costs. While it is more costly to lay offshore gas pipelines, right of way and other costs are less. To look at an example from the table, a 12.75 inch diameter pipeline is $75,000 per inch-mile. The cost per mile of this pipeline is $956,250.

Recent studies have shown that CO_2 pipeline transport costs for a 62 mile pipeline transporting 5 megatonnes per year range from approximately $1 per tonne to $3 per tonne, depending on factors such as terrain, flow rate, population density, labor costs, etc.[84]

Table 10 CO_2 Pipeline Costs for Example Cases

CARBON DIOXIDE PIPELINES

Outside Diam. Inches	Inside Diam. Inches	Wall Thickness Inches	Pipeline Cost in $/Inch-Mile	Total Cost of Service in $/metric ton per 75 miles or 121 km	Flow Capacity in metric tons/day	Flow Capacity in million standard cubic feet per day (60 degrees F and 14.73 psi)	Number of 500 MW IGCC plants accomodated
12.75	12.0	0.39	$ 75,000	$4.36	10,775	203	0.97
16	15.0	0.49	$ 78,116	$3.25	19,139	361	1.73
24	22.5	0.73	$ 84,119	$2.02	53,385	1,007	4.83
30	28.2	0.92	$ 86,399	$1.56	93,887	1,771	8.49
36	33.8	1.10	$ 88,678	$1.27	148,913	2,808	13.46
42	39.4	1.28	$ 90,958	$1.10	219,942	4,148	19.88

Note: 500 MW IGCC plant would produce 512 metric tonnes of CO_2 per hour. Of this, 90% or 461 tonnes would be captured. Maximum CO_2 tranport needs would be 11,064 tonnes per power plant per day. Cost of service based on 7 cents per kWh electricity.

Example Spatial Assumptions

	Miles	$/Mile per Tonne	Cost per Tonne	Annual Cost per Power Plant @85 Utilization Rate
Single Power Plant Pipeline (12 inch, small gathering)	**25**	$0.058	$1.45	$4,986,315
Two Power Plant Pipeline (16 inch, large gathering)	**25**	$0.043	$1.08	$3,717,211
Eight Power Plant Pipeline (30 inch, mainline)	**100**	$0.021	$2.07	$7,117,230
Total Distance & Costs	**150**	**$0.031**	**$4.61**	**$15,820,756**

5.4 CO_2 Storage Options

There are several different options for long term 'permanent' carbon dioxide storage:[85] a) ocean storage by pumping CO_2 deep into the base of the water column near the seafloor, b) chemical storage by binding CO_2 with other chemicals (either in the subsurface reservoir or at a surface plant) to form an inert substance, and c) geological storage by pumping CO_2 underground into depleted oil and natural gas

[84] CCS Task Force, 2010, Report of the Interagency Task Force on Carbon Capture and Storage, Washington, D.C., http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf.

[85] Biological sequestration (such as enhancing of natural sinks such as forests and soil) is not directly applicable to power plant emissions.

reservoirs and in deep saline reservoirs. Of the three options, geological storage is the most promising for storage of large scale emissions, and hence this option will be discussed in more detail (see Boxes 1 and 2 for brief descriptions of ocean and chemical storage).

Box 1: Ocean storage

Ocean storage involves the transportation of CO_2 via pipelines or ships and injecting it into deep water. The viability of ocean storage has not yet been demonstrated in a large scale, although there has been some theoretical, laboratory and modeling studies. The ocean has already absorbed about 50% of the total anthropogenic carbon emissions over the past 200 years, and it is already becoming more acidic. Technically, there is practically no limit to the storage capacity in the oceans, and the stored CO_2 can be isolated from the atmosphere for several hundreds of years. The potential for longer storage increases with deeper injection. Cost estimates of ocean storage are in the range of \$5 – 30/tCO_2, including the cost of transporting the CO_2 100-500 km offshore.[86]

The environmental impacts of ocean storage are potentially great. However, our present understanding of long term impacts on deep ocean ecosystems is limited.[87] Furthermore, public perception appears to be against ocean storage, in contrast with geological storage. Hence, ocean storage is not currently considered a viable option for storing CO_2.

Injection of CO_2 in deep geological reservoirs – i.e., geological storage – is becoming an important option for storing large scale CO_2 captured from power plants and other industrial facilities. CO_2 can be injected and stored in depleted oil and gas reservoirs, enhanced oil and gas production, deep saline aquifers, unmineable coal beds, and deep water-saturated mineral rocks.

[86] These costs do not include the cost of piping the CO_2 to the shoreline or the monitoring costs after injection.
[87] IPCC, 2005, IPCC Special Report on Carbon Dioxide Capture and Storage: Technical Summary.

Box 2: Chemical storage

Chemical storage involves fixing the CO_2 to alkaline and earth-alkaline oxides that are present in natural silicate mineral rocks (such as serpentine, olivine, enstatite, talc, etc.) to form carbonates and silica. Chemical reaction is a permanent option for storing CO_2, as it is an exothermic reaction. The technology for mineral carbonation is not yet mature to allow for a proper assessment of costs and performance; nonetheless, there is interest in chemical storage because the vast quantity of silicate mineral rocks present in the Earth's crust is more than enough to permanently store all of CO_2 that can be generated by fossil fuel reserves.

There are two options for mineral carbonation: in-situ and ex-situ carbonation. In-situ carbonation involves the injection of CO_2 directly into the silicate rich geological strata, and is one of the storage mechanisms relevant for CO_2 storage in geological reservoirs. Ex-situ carbonation involves a separate carbonation plant wherein natural silicates or alkaline industrial waste are processed and prepared for carbonation with the captured CO_2 – about 2-4 tons of silicate will have to mined to store a ton of CO_2.[88] Although the carbonation reaction is exothermic,[89] the pre-processing procedures, including mining, will require a significant amount of energy input. Large quantities of by products, about 3-5 tons of silica and carbonates per ton of CO_2, will have to be properly disposed back into mines or be used as landfill, roadfill and for other industrial purposes. The estimated cost of ex-situ mineral carbonation is quite high – about \$50-100/tCO_2 net mineralized. [90]

Underground injection of CO_2 is a commercial technology and it has been used since the 1970s for enhanced oil recovery (EOR) – wherein CO_2 and water is periodically injected to extract more oil out of a reservoir. Although injecting CO_2 for EOR is not aimed at storage (especially since injectors have to purchase CO_2), a fraction of the injection CO_2 remains captured in the reservoir. Historically, CO_2 purchases comprise about 33 to 68 percent of the cost of a CO_2-EOR project.[91] The CO_2 for EOR is currently sourced from both natural and anthropogenic sources, which provide 79 percent and 21 percent, respectively, of CO_2 supply.[92] Some of the natural CO_2 reservoirs include the Bravo Dome (New Mexico), McElmo Dome (Colorado), Escalante Reservoir (Utah), Farnham Reservoir (Utah), Woodside Reservoir (Utah), LaBarge Dome (Wyoming), and Jackson Dome (Mississippi).[93]

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[88] IPCC, 2005, IPCC Special Report on Carbon Dioxide Capture and Storage: Technical Summary.
[89] The kinetics of the carbonation process can be slow; thereby, the silicates have to be heated to enhance kinetics.
[90] IPCC, 2005, IPCC Special Report on Carbon Dioxide Capture and Storage: Technical Summary.
[91] EPRI, 1999 (citation unavailable)
[92] NETL, 2008, Existing Coal Power Plants and Climate Change: CO_2 Retrofit Possibilities and Implications (full citation unavailable)
[93] EPA, 2010, Report of the Interagency Task Force on Carbon Capture and Storage, Washington, D.C. http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf.

Box 3: Existing CO_2 storage projects[94]

The Sleipner project in Norway, started in 1996, is the longest-running commercial-scale CO_2 storage project in the world. The Norwegian government imposes a carbon tax on vented CO_2 emissions from natural gas production projects. Statoil separates the CO_2 from a produced natural gas and injects 1 megatonne of 98% pure CO_2 annually through one horizontal well into the 250m thick Utsira Sand, a high permeability, high porosity sandstone unit roughly 1,100m below the sea surface. The reservoir is sealed with shales, and mudstones and shale baffles (discontinuous shale lenses) are present in the reservoir to further slow down upward movement of CO_2.

The Weyburn project is a combined EOR/geologic sequestration project operated by EnCana in southern Saskatchewan in Canada near the North Dakota Border. The project uses a mix of 29 horizontal and vertical wells to annually inject roughly 1.8 megatonnes of 96% pure supercritical CO_2 from a nearby synfuels plant into two adjacent carbonate layers. Successful CO_2-EOR operations since 2000 at the site have demonstrated the applicability of EOR/GS technology to thin, less-than-ideal formations at moderate depth.

In Salah is a commercial-scale CO_2 storage project located in the Sahara Desert in Southern Algeria. The projected is operated by BP and it uses three horizontal wells to annually inject roughly 1.2 megatonnes of supercritical 98% pure CO_2 separated from produced natural gas. The reservoir is a 1,800m deep, 21m thick, low-porosity, low-permeability laterally heterogeneous muddy sandstone. The project has demonstrated that reservoirs previously thought of as marginal or unusable could successfully store commercial-scale quantities of CO_2.

The Snøhvit Project in the Barents Sea is also based on separating CO_2 from produced natural gas from the Snøhvit Field. The CO_2 is sent back near the site of production via pipeline and injected through a dedicated well 2,600 meters beneath the seabed at the edge of the reservoir in the Tubåsen sandstone formation, located below the producing formations. The project is expected to store approximately 0.7 megatonnes CO_2 annually.

Commercial-scale engineered CO_2 storage projects are already underway in Norway (North Sea), Canada (Weyburn), and Algeria (In Salah) —see Box 3 for a brief description of the current large scale storage operations—with many future projects planned in Canada, China, Australia, U.S.A., Poland, Japan, Netherlands and Norway.[95] The technology for injecting gases into geological media is well established,[96] and it requires many of the same technologies developed in the oil and gas exploration and production industry, such as well drilling, injection, reservoir

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[94] EPA, 2010, Report of the Interagency Task Force on Carbon Capture and Storage, Washington, D.C, http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf.
[95] IPCC, 2005, IPCC Special Report on Carbon Dioxide Capture and Storage: Technical Summary.
[96] Fluids have been injected into the deep subsurface for a long time to dispose of unwanted chemicals, pollutants, and petroleum by-products to enhance oil and gas recovery. Natural gas has also been injected and stored in sub-surface reservoirs in many places (IPCC, 2005).

capacity/storage assessment, simulation of reservoir dynamics, monitoring methods, etc.

Storage Options

Geological formations most suitable for storage are in sedimentary basins, wherein the subsurface has mineral rock formations, organic matter, cavities, and fissures. The pore spaces, cavities, and open fractures are mainly filled with water and in some cases oil and gas. Target formations with the greatest geologic storage capacity include deep saline formations, depleted oil and gas reservoirs, unmineable coal seams, and other formations:[97]

Deep saline formations: These formations are sedimentary rock layers that are generally more than 800 meters deep and are saturated with waters or brines that have a high total dissolved solids (TDS) content (i.e., over 10,000 mg/L TDS). This is a Safe Drinking Water Act criterion that does not apply to the OCS except where an onshore freshwater formation extends across the state/federal boundary into the OCS. Deep saline formations are found throughout the United States. The formations suitable for storage are overlain by laterally extensive, impermeable formations that may restrict upward movement of injected CO_2.

Depleted oil and gas reservoirs: These reservoirs are prime candidates for CO_2 storage because of their demonstrated structural integrity (by storing hydrocarbons in physical traps, sometimes for many millions of years). The same trapping mechanisms in which hydrocarbons are commonly found (i.e., structural trapping by faulted, folded, or fractured formations, or stratigraphically, in porous formations bounded by impermeable rock formations) can effectively store CO_2 for geologic sequestration in depleted oil and gas reservoirs.

Unmineable coal seams: Coal seams that are inaccessible to mining can be used to store CO_2 using adsorption trapping. Currently, enhanced coalbed methane (ECBM) operations exploit the preferential chemical affinity of coal for CO_2 relative to the methane that is naturally found on the surfaces of coal. Studies suggest that for every molecule of methane displaced in ECBM operations, three to thirteen CO_2 molecules are adsorbed. Higher coal rank might enhance the relative adsorptive capacity of methane and CO_2.[98] This process effectively "locks" the CO_2 to the coal, where it remains sequestered. However, permeability of coal for CO_2 is an issue, and the permeability decreases with increasing depth.

Several other types of geological formations are being explored as potential storage options, including basalts, salt caverns, unused mines, underground coal gasification (UCG) voids, shales, and deep cool sub-surface storage as liquid CO_2 and CO_2

[97] CCS Task Force, 2010, Report of the Interagency Task Force on Carbon Capture and Storage, Washington, D.C.
[98] Reeves, et al., 2004 (citation unavailable)

hydrate. Technology for storage in these options and scientific understanding is at the research stage.

Trapping Mechanisms

When CO_2 is injected into different types of formations, the gas will undergo a number of transformations – it can diffuse and displace existing fluids, mix or dissolve with the existing fluids, chemically react with minerals present in rocks, adsorb onto organic material, be trapped in pore spaces by capillary action, or a combination of all these processes.

The primary mechanisms of trapping relevant for storage include[99]

- Physical trapping: The injected CO_2 is trapped by cap-rocks of low permeability, such as shale, salt beds, or gas hydrates. Many of the physically bound traps that contain oil or natural gas can also physically trap CO_2.
- Hydrodynamic trapping: The gaseous CO_2 injected into saline formations will be trapped in saline because of the very slow upward migration of the gas through the aquifer (timescale of tens to hundreds of years or longer[100])—also known as migration assisted storage (MAS). The upward migration occurs because of the buoyancy of CO_2 gas in water. Once fully migrated to the top of the saline reservoir, the gas can be physically trapped. At longer times (thousands to millions of years) the gas will slowly dissolve into the saline (solubility trapping) or be mineralized (geochemical trapping).
- Solubility trapping: As the gaseous CO_2 dissolves in the water, it becomes converted into a weak carbonic acid. The dissolution will prevent the upward migration since the CO_2 is no longer in a separate phase.
- Geochemical trapping: The carbonic acid, formed when CO_2 is dissolved in water, can react with minerals in the rock formation to form carbonates. The chemical reaction to carbonates is the most permanent form of storage.
- Adsorption trapping: Injecting CO_2 into coal seams or organic-rich shales might result in CO_2 being bound to micropores in coal, shale and other surfaces. The term for this is Adsorption Storage Site Phases
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The geology and geological attributes of the subsurface are highly variable among regions, basins, and even among sites within any basin. Therefore, the appropriateness of a storage site has to be determined through a process of site characterization and selection of potential sites. The appropriateness of a storage site (mostly defined by the safe and permanent storage of CO_2) is determined primarily by three principal requirements:

- Capacity: i.e., whether sufficient storage volume is available and can be accessed;

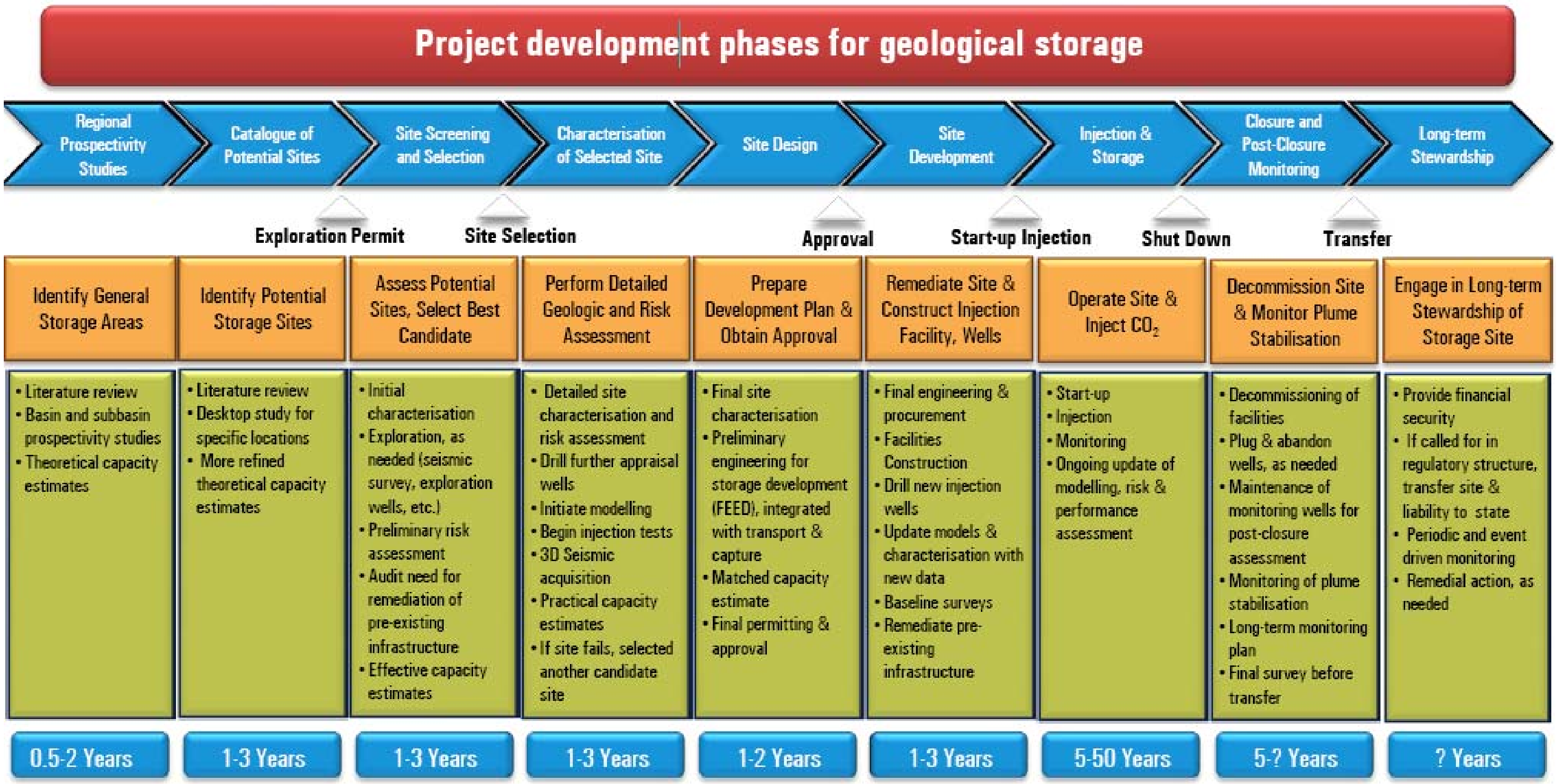
[99] IPCC ,2005, IPCC Special Report on Carbon Dioxide Capture and Storage: Technical Summary.
[100] Where the distance between injection point and the region of impermeable layer may be hundreds of kilometers, the hydrodynamic trapping time (CO_2 migration time) can be millions of years (Bachu et al., 1994, "Aquifer Disposal of CO_2: Hydrologic and Mineral Trapping, Energy Conversion and Management, Vol. 35 (4), pp. 269-279).

- Integrity: i.e., whether the site is secure with negligible risk of leakage; and
- Injectivity: i.e., whether suitable reservoir properties exist for sustained injection at industrial supply rates into the geological formations, or whether the reservoir properties can be engineered to be suitable.[101]

The entire chain of activities needed for the entire life cycle of a CO_2 storage site is shown below in **Figure 23**. As one passes through these different stages, a storage site developer achieves progressively more detailed knowledge about the storage capacity of the site and the characteristics of the storage reservoir, with reduction in uncertainty and better understanding of technical risks. The timeframes in **Figure 23** are generic in nature, and actual timeframes for specific projects will depend on the site characteristics, scope of activities required, regulatory framework, and the industry environment as well as public attitudes and how long it takes to gain public acceptance.

[101] For example, by fracking the reservoir or by extracting formation water to prevent reservoir pressure build-up.

Figure 23 Phases of Geological Storage of CO_2



Note: Orange boxes refer to "Project Developer Goals"; Green boxes refer to "Developer Activities"

Source: Senior CCS Solutions and Bradshaw Geoscience Consultants

5.5 Storage Costs

The cost of storage in geological subsurface varies according to site-specific factors such as onshore vs. offshore, reservoir depth, and geological characteristics. Costs associated with CO_2 storage have been estimated to be approximately $0.4–20/tonne.[102] Representative cost estimates in saline formations and depleted oil and gas reservoirs are between $0.4-$12 per tonne of CO_2 injected, with an additional $0.16-$0.30 per tonne for monitoring and verification.[103] Offshore costs tend to be on the upper end of these ranges. When CO_2 storage is combined with EOR or CBM, the economic value of CO_2 can result in a net benefit for injecting CO_2 underground.[104]

ICF has developed detailed modeling of storage costs for DOE and EPA, including capital and operating costs for pumps, pipelines, injection wells, and monitoring wells and equipment. These costs are typically functions of key engineering parameters such as depth, pressure, and flow rate. Other cost elements are initial geological and geophysical (G&G) survey and regulatory costs for site selection, permitting and certification, and recurring non-well monitoring during the project injection period and afterwards. There are also cost parameters for contingencies and for general and administrative costs (a.k.a. owner's costs). Payments to the landowner for surface disturbance and injection rights are included as are "insurance payments" to a government entity that is assumed to take over long-term liability for the site after its abandonment.

ICF GeoCAT Model

ICF developed the GeoCAT (Geologic Sequestration Cost Analysis Tool) model to evaluate the economics of geologic sequestration under a range of geologic and engineering scenarios for both onshore and offshore regions of the U.S. The model combines available sequestration capacity by state and geologic setting for the U.S. with costing algorithms for individual components of geologic sequestration of CO_2. The cost algorithms in GeoCAT are based on historical costs in the oil and gas industry (e.g., wells, pipelines, production platforms) with adjustments to account for CO_2-specific characteristics such as higher pipeline operating pressures and the corrosivity of CO_2 when mixed with water. The outputs of the model are regional sequestration cost curves that indicate how much potential storage capacity is available at different CO_2 price points. The details of the offshore costs in the model are presented below.

A detailed characterization and model of the individual cost components of geologic sequestration of CO_2 was developed in support of EPA's draft Federal Requirements under the Underground Injection Control (UIC) Program for Carbon Dioxide Geologic

[102] Cost estimates are limited to capital and operational costs, and do not include potential costs associated with long-term liability.
[103] IPCC, 2005, IPCC Special Report on Carbon Dioxide Capture and Storage: Technical Summary.
[104] Data for onshore EOR indicates a net benefit of $10-16/t$CO_2$, including costs of geological storage. With the price of oil and gas increasing, the economic value of CO_2 might even be higher (IPCC, 2005).

Storage Wells. EPA's rule will provide minimum federal requirements for owners and operators of sequestration operations. It is intended to protect underground sources of drinking water as well as to provide regulatory certainty and permitting consistency for industry as this key climate mitigation technology is developed.

The GeoCAT model is used to evaluate cost/sequestration potential relationships (cost curves) by state and geologic category and regulatory alternative. The cost analysis includes 120 unit cost elements grouped into categories such as geologic site characterization, monitoring, and injection well construction. Depending on the nature of each cost element, it is specified as cost per site, per square mile, as a function of well depth, per labor hour, or other specification. These individual cost specifications are imported into various scenarios to simulate project level costs. Each project has specifications for volume of CO_2 injected, depth, number of injection and monitoring wells, and other factors. Based on the timing of expenses and financial assumptions, these costs are translated in the model into dollars per metric ton of CO_2 injected.

The GeoCAT model includes a *unit cost specification module*, a *project scenario costing module*, and a *geologic and regional cost curve module*. The unit cost module includes data and assumptions for 120 unit cost elements, as described below. Each cost element has a corresponding equation that is used to calculate costs. Once these cost equations have been determined, they are incorporated into the *project scenario costing module* for economic analysis of specific sequestration scenarios by reservoir type. The *regional curve generating module* takes input from the other modules to generate cost of sequestration curves by state, region, and reservoir type.

Sequestration project scenarios include specifications of project area, reservoir depth, thickness, well injectivity, number of wells through time, and other parameters.

The sequestration cost analysis includes a unit cost module with 120 cost elements. A unit cost item is a specific cost element such as the cost of a specific aspect of site characterization or the cost to drill and complete an injection well. Depending on the nature of each cost element, it is specified as a cost per site, cost per square mile, cost as a function of well depth, cost per labor hour, or other specification. Sources of cost data include API's "Joint Association Survey of Drilling Costs", EIA data on operating and equipment costs, the Land Rig Newsletter for rig rates, and Petroleum Services of Canada data. Other sources include the Preston Pipe Report for casing and tubing, the Bureau of Labor statistics for labor costs, and pipeline cost data from the Oil and Gas Journal. Costs of monitoring technologies are from the literature on DOE pilot projects and from an EPA-sponsored meeting in New Orleans. The following is a summary of major cost categories and the approach taken to specifying costs in the model.

Geologic Site Characterization
The purpose of site characterization is to determine whether a site is suitable and safe for sequestration. The process includes geologic, geophysical, and engineering evaluation. A determination is made of whether the reservoir has adequate porosity, permeability, and continuity for long term injection. The ability of overlying units to confine the injected CO_2 is also evaluated. Other evaluation includes the mechanical properties of the reservoir, information on underground sources of drinking water, and information on past drilling penetrations. Significant components of site characterization costs include 3-D seismic data acquisition, development of maps and cross sections, and evaluation of geomechanical and geochemical data.

Monitoring
After injection begins, it is necessary to monitor the movement of CO_2 in the subsurface. This includes monitoring of pressure during the injection process, monitoring of the migration and distribution of the CO_2, and monitoring of the shallow subsurface and at the surface to detect possible leaks. Depending upon the scenario, it may be required to have monitoring wells above the injection zone and into the injection zone. Significant components of potential monitoring costs include the drilling of monitoring wells above and into the injection zone, implementation of the subsurface and surface monitoring, and periodic seismic surveys and reservoir modeling.

Injection Well Construction
The design of a CO_2 injection well is similar to that of a conventional gas injection well or a gas storage well, with the exception that much of the downhole equipment must be upgraded for high pressure and corrosion resistance. Upgrades may include special casing and tubing, safety valves, and cements. A well program is designed prior to drilling to determine the drilling plan and casing points. This design incorporates what is known about the geology and engineering aspects of the location. Major cost components include the drilling and completion of the injection wells, engineering and design, corrosion-resistant tubulars, and wellhead and control equipment.

Area of Review and Corrective Action
This aspect of the cost analysis includes fluid flow and reservoir modeling to predict the movement of the injected CO_2 and pressure changes during and after injection. It also includes those cost elements pertaining to the identification, evaluation, and remediation of existing wells within the area of review.

Well Operation
This cost category includes those costs related to the operation of the injection wells including measuring and monitoring equipment, electricity costs, operation and maintenance (O&M) costs, pore space costs, contribution to a long term monitoring fund, repair and replacement of wells and equipment, and estimated costs for the possibility of failure at the site and the need to relocate a sequestration operation.

Mechanical Integrity Tests
A CO_2 injection well will periodically undergo integrity testing to ensure mechanical soundness, lack of corrosion, and ability to sustain pressure. There are several such tests that are typically used, and they include both pressure tests and wireline logs. These technologies are well established and have been used for decades for underground injection operations.

Post Injection Well Plugging and Site Care
After the injection phase has ended, it is necessary to prepare the site for long-term monitoring and eventual closure in a safe and secure manner that protects potential sources of drinking water. This involves the plugging of injection wells, removal of surface equipment, and land restoration. It also includes long term requirements for monitoring the site to ensure safety and to confirm an understanding of the CO_2 distribution in the subsurface. Major cost components include plugging injection and monitoring wells, and seismic and other surveys.

Financial Responsibility
It will be necessary for the operator to demonstrate and maintain financial responsibility, and have the resources for activities related to closing and remediating the site. The EPA rule only specifies a general duty to obtain financial responsibility acceptable to the Director, and EPA will provide guidance to be developed at a later date that describes the types of financial mechanisms that owners or operators can use to meet this requirement.

General and Administrative
General and administrative costs are included as unit costs for both the project development and operating phases. The costs are specified as a percentage of either capital costs or annual operating costs.

BOEM Cost Assumptions

As part of the analysis of offshore sequestration costs, ICF used the current BOEM cost assumptions. These are the assumptions for the costs of offshore platforms, wells, and pipelines that are used by BOEM in their economic studies.[105] These costs, in 2008 dollars, are presented in **Table 11**.

In the model, ICF used the development well costs and assumed the shallow water depths (less than 200 meters).

[105] Costs are those used in the BOEM's economic impact model MAG-PLAN.

Table 11 BOEM MAG-PLAN Platform, Well, and Pipeline Cost Assumptions

Water Depth (m)	Facility Type	Platform Cost Only mean value ($ million)	**Production Facility Platform** platform + production equipment + infield flow lines mean value ($ million)
0-60	Fixed Platform	$6.37	$7.822
0-60	caisson or well protector	$2.53	$2.661
60-200	Fixed Platform or spar	$16.15	$17.102

Water Depth (m)	Initial Exploratory Well Cost (2008$) Well Depth (ft)		
	0 to 15,000	15,000 to 18,000	18,000+
0-60	$8,137,500	$18,066,667	$32,037,000
60-200	$18,709,500	$35,825,000	$48,885,667

Water Depth (m)	Initial Development Well Cost (2008$) Well Depth (ft)		
	0 to 15,000	15,000 to 18,000	18,000+
0-60	$6,095,500	$14,424,667	$27,985,500
60-200	$8,228,000	$18,347,000	$36,067,000

Estimated Pipeline Cost Per Mile by Water Depth (2008$, Thousand)		
Water Depth (m)	WD Midpoint (m)	Line Est. Cost Per Mile $ million
0-60	30	$1.76
60-200	130	$1.78

Source: Eastern Research Group, 2012[106]

[106] Eastern Research Group, Inc., 2012, Gulf of Mexico MAG-PLAN 2012: Updated and Revised Economic Impact Model, U.S. Department of Interior, Bureau of Ocean Energy Management, Gulf of Mexico OCS Region, New Orleans, LA.

Factor costs for drilling, equipment, and services for the offshore are generally more expensive than for onshore regions as listed here:

- Platforms are expected to be required for offshore geologic storage sites to provide a base for injection wells, monitoring wells, pumps, measurement equipment, monitoring equipment, etc. As shown in Table 11, the cost of a platform is approximately 6 to 16 million dollars for shallow water areas of less than 200 meters water depth.
- The cost of drilling is higher ($2,500 per foot offshore versus $200 to $400 per foot for onshore.)
- Operating costs tend to be higher in offshore regions due to the need to transport personnel, supplies and equipment over water.

To some extent these higher costs can be offset in offshore regions if the carbon dioxide volumes that can be injected per well are greater. There may also be cost savings in offshore areas due to the fact that drinking water is not present and that certain costs such as sampling or monitoring of drinking water aquifers will not be needed. Offshore regions would likely have lower "NIMBY" (not in my back yard) cost impacts as well. Even with such offsetting factors, as is shown in Table 12 below, the offshore storage capacity tends to be more expensive on a dollar per unit basis as compared to onshore regions.

5.6 Analysis of Annual Injection Volumes with and Without the OCS

Table 12 summarizes the GeoCAT economic analysis of CO_2 storage potential. Storage volumes are presented both in terms of total geologic storage potential and in terms of assumed annual injection potential for modeling. Annual volumes are computed by taking the geologic storage capacity for each cost step and dividing by 50. The factor of 50 represents the fact that any given storage site will be operating for up to 50 years and that it will take time to develop available storage sites in any given area.

The table presents total volumes and those volumes determined to be economic at $10 and $5 per tonne and for "negative" cost components. The negative cost components are primarily CO_2 EOR.

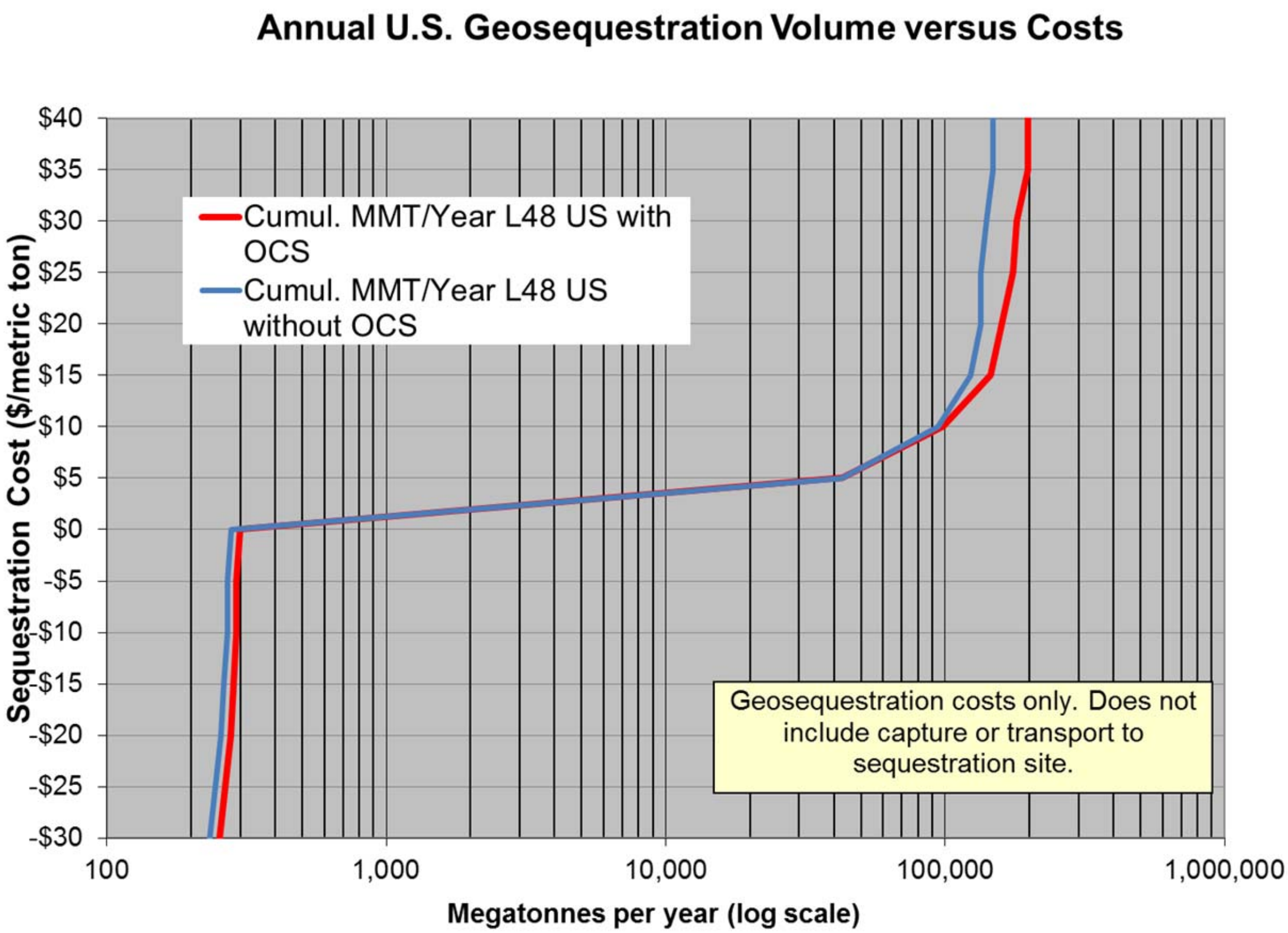
Figure 24 is a cost curve summarizing the GeoCAT analysis of annual injection volumes in million tons per year as a function of sequestration costs. The chart illustrates that approximately 47,000 megatonnes per year of storage potential is available for under $5 per tonne. At a cost of $10 or less there is 108,600 megatonnes per year of storage capacity. It is important to note that because of the higher factor costs for offshore regions discussed above, the amount of storage capacity added in the $0-$5 cost step is zero for the offshore regions, while substantial capacity is added for the onshore areas. On the other hand, both offshore and onshore regions add large volumes of capacity in the $5-$10 cost step.

Table 12 Lower-48 CO_2 Storage Capacity vs. Cost on Total and Annual Injection Capacity Basis

	Quantity Without OCS	OCS Quantity*	Lower-48 Total
GEOLOGIC AND ECONOMIC STORAGE CAPACITY			
Total Geologic Capacity (Gigatonnes)			
Total	7,444	3,643	11,087
EOR	15.0	1.5	16.5
Total Economic Capacity below $10 per metric ton (Gigatonnes)			
Total	5,184	250	5,434
EOR	15.00	1.13	16.13
Total Economic Capacity below $5 per metric ton (Gigatonnes)			
Total	2,355	1.13	2,356
EOR	15.00	1.13	16.13
Total Economic Capacity with Negative cost (Gigatonnes)			
Total	15.38	1.13	16.51
EOR	15.00	1.13	16.13
ANNUAL INJECTION CAPACITY			
Annual Capacity for Resource below $10/metric ton as Defined for Current Study (Megatonnes per year)			
Total	103,680	5,000	108,680
EOR	300.0	22.6	322.6
Annual Capacity for Resource below $5/metric ton as Defined for Current Study (Megatonnes per year)			
Total	47,090	22.6	47,113
EOR	300	22.6	323
Annual Capacity for Resource with Negative Cost (Megatonnes per year)			
Total	308	22.6	330.2
EOR	300	22.6	322.6

* Total offshore EOR potential is 1.5 Gt. The difference between 1.5 and 1.13 Gt is the portion that is above $10 per tonne.

Figure 24 Geosequestration Annual Volume Versus Sequestration Cost from GeoCat Model



Source: Modified from analysis for ICF/INGAA study.[107] Annual volume is computed as total capacity divided by 50 years.

[107] ICF International, 2009, "Developing a Pipeline Infrastructure for CO_2 Capture and Storage: Issues and Challenges," prepared for the INGAA Foundation, Washington, DC, February, 2009.

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6. EPA Regulatory Policies toward Geologic Storage of Carbon Dioxide

6.1 Introduction

This chapter provides a summary of ongoing regulatory efforts at EPA related to the underground geologic storage of carbon dioxide. The three main initiatives are:

1) the creation of a new Class VI designation under the Underground Injection Control program for CO_2 injections wells and sites,
2) reporting of emissions at storage sites under the Mandatory Reporting Rule subparts RR and UU and,
3) an effort to exempt CO_2 storage from Resource Conservation and Recovery Act (RCRA) provisions.

The CCS Task Force Report has noted that there is ongoing uncertainty on how environmental statues will be applied for CCS in the United States, although there is already a sufficient regulatory framework for CCS projects to be deployed in the near future. The Task Force recognized that facilitation of widespread, cost-effective deployment of CCS would require a future enhanced regulatory framework to balance multiple goals: reducing CO_2 emissions; increasing energy security; and protecting human health, the environment, and our resources. Such a framework could either a) be based on existing authorities for regulations or b) create a new comprehensive statutory framework covering all aspects of CCS. There is also the issue of addressing long term liabilities arising from CCS.

Activities associated with CCS will likely face various Federal and State environmental planning review obligations. The National Environmental Policy Act (NEPA), 42 United States Code (U.S.C.) §§ 4321 to 4370f,[108] is likely the most important federal statute that will be applicable for CCS projects. NEPA calls for an environmental review process, coordinated by different federal agencies, and an Environmental Impact Statement (EIS) needs to be developed before a final permitting decision is made. The CCS Task Force Report discussed the applicability of NEPA:[109]

> NEPA applies to a broad range of actions subject to Federal control or responsibility. Use of Federal or Tribal lands for the purposes of CO_2 pipeline

[108] See CCS Task Force Report (2010) for more details.
[109] CCS Task Force (2010), Report of the Interagency Task Force on Carbon Capture and Storage, Washington, D.C.

siting or sequestration will require NEPA analysis. Non-Federal projects, which are not normally subject to NEPA, may become Federal actions where they are financed, assisted, or approved in whole or in part by the Federal government. This is a very complex area of the law and requires a fact-intensive analysis to determine when a private project has become federalized.

In the short term, CCS project activities will likely involve Federal agencies in planning, financing and permitting of CO_2 storage on private and federal lands, and hence NEPA will be applicable to these activities. For example, the Department of Energy prepared the EIS for the proposed FutureGen project, as required by NEPA.[110] The FutureGen EIS evaluated the environmental impacts that would arise from DOE funding for the FutureGen project at four potential sites. Some activities may be exempt from NEPA if they are subject to functionally equivalent processes. For example, an Underground Injection Control (UIC) permit is required under the Safe Water Drinking Act (SDWA), and the UIC permit process is considered as being functionally equivalent to the NEPA process.

The U.S. Environmental Protection Agency (EPA) has a particularly important role in regulating CCS activities in the United States. The primary goal of EPA is to ensure that geological storage (GS) activities are conducted safely and effectively. EPA's responsibilities related to GS include:

- Developing Greenhouse Gas Reporting Mechanisms for GS Under the Clean Air Act (CAA);
- Developing UIC Regulations for CO_2 injection Under the Safe Drinking Water Act (SDWA);
- Evaluating Risks to Human Health and the Environment from CCS through the Vulnerability Assessment Framework;
- Evaluating the applicability of Resource Conservation and Recovery Act (RCRA) Subtitle C (hazardous waste management) and liability under Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) for CO_2 streams and their underground injection.

In this chapter, a summary of the above issues within the jurisdiction of EPA is presented.

6.2 Greenhouse Gas Reporting Rule

In October 2009, the EPA issued the Mandatory Reporting of Greenhouse Gases Rule under the CAA section 114, requiring the reporting of greenhouse gas (GHG) data and other relevant information from large sources and suppliers in the United States. The purpose of the rule is to collect accurate and timely GHG data to inform future policy

[110] http://www.netl.doe.gov/technologies/coalpower/futuregen/eis/

decisions. Implementation of this Rule is through the Greenhouse Gas Reporting Program (GHGRP).

There are two relevant subparts of the GHGRP that are relevant to CCS—Subpart PP, which applies to suppliers of CO_2 for CCS, and Subpart RR, which applies to CO_2 injection for GS.

Subpart PP includes facilities that capture or CO_2 for underground injection (for EOR and GS), produce CO_2 from CO_2 reservoirs, and export or import bulk CO_2. These facilities will be required to regularly monitor (using flow meters) and report the mass of CO_2 captured from production process units and extracted from production wells, and the mass of CO_2 that is imported and exported.[111]

Subpart RR includes facilities that conduct geologic storage by injecting CO_2 for long-term containment in subsurface geologic formations.[112] All of these facilities would also have to obtain a UIC Class VI permit (see below). The reporters would have to:

- Report basic information on CO_2 received for injection;
- Develop and implement an EPA-approved site-specific monitoring, reporting, and verification (MRV) plan; and
- Report on the annual monitoring activities and the amount of CO_2 that is stored using a mass balance approach.

The reporters are expected to report basic information under the Subpart RR rule by March 31, 2012 for the year 2011, and include the annual monitoring activities and the amount of stored CO_2 when the MRV plans are approved and implemented. Research and development projects related to geological storage are exempt from the Subpart RR requirements, but they still have to submit information related to Subpart UU. EOR projects that report under Subpart UU, can also report under Subpart RR by meeting its requirements.

Basic Information

It is expected that the information obtained by EPA under the Subpart RR will enable EPA to monitor the growth and effectiveness of geological storage as a GHG mitigation technology over time and to evaluate relevant policy options.

The basic information to report includes:

- the mass of CO_2 received;
- the mass of CO_2 injected;
- the mass of CO_2 produced (i.e., mixed with produced oil, gas, or other fluids);
- the mass of CO_2 emitted from surface leakage, based on site-specific MRV plan;

[111] http://www.epa.gov/climatechange/emissions/subpart/pp.html

[112] Subpart UU covers facilities that inject CO_2 for purposes other than geological storage (e.g., enhanced oil or gas recovery).

- the mass of CO_2 equipment leaks and vented CO_2 emissions from sources between the injection flow meter and the injection wellhead or between the production flow meter and the production wellhead (based on procedures in Subpart W); and
- the mass of CO_2 sequestered in subsurface geologic formations (calculated from the other quantities).

The Subpart RR rules also specify records retention requirements for reporters to follow, with a requirement to maintain all records for at least three years.

MRV Plan

The MRV plan needs to have five key elements:

- Delineation of the maximum monitoring area (MMA) and the active monitoring area (AMA).
- Identification and evaluation of the potential surface leakage pathways and an assessment of the likelihood, magnitude, and timing, of surface leakage of CO_2 through these pathways in the MMA.
- A strategy for detecting and quantifying any surface leakage of CO_2 in the event leakage occurs.
- An approach for establishing the expected baselines for monitoring CO_2 surface leakage.
- A summary of considerations made to calculate site-specific variables for the mass balance equation.

A reporter in the MRV plan needs to show that the approach taken to address each of the components above and provide an adequate level of assurance that the regulatory requirement will be met. This assurance could include a demonstration that the statistical basis of the monitoring strategy or the quantification method meets a certain level of performance. In some cases, the MRV plan may not include specific details of implementation because there are many site-specific or event-specific factors that will influence the selection of a particular method or technology.

EPA is not prescribing specific monitoring technologies in the MRV plan, recognizing that facilities can propose a cost- effective approach that is suitable to the geology and conditions at their site. This flexible approach is warranted because (1) each facility will have a unique set of geologic, environmental, and operational conditions, (2) as projects mature, reporters will collect new information and may choose to improve their conceptual site models and modify their monitoring, modeling, and evaluation techniques, and (3) uncertainties and inherent variability in the natural systems will necessitate modifications to the selected methods and approaches over time and in response to unexpected events.

EPA plans to follow an iterative approval process, obtaining additional information from the reporter, if necessary. It is expected to send a notice of receipt of the MRV plan within 15 days, and will determine the completeness of the MRV plan with 45 days.

After the determination of completeness, EPA will review for 60 days and request additional information, if needed. Following the review, within a reasonable period of time, EPA is expected to issue a final MRV plan as submitted, or with revisions. EPA will post the approved MRV plan on a public Web site, subject to any limitations or requirements in its CBI determination.

Monitoring Areas

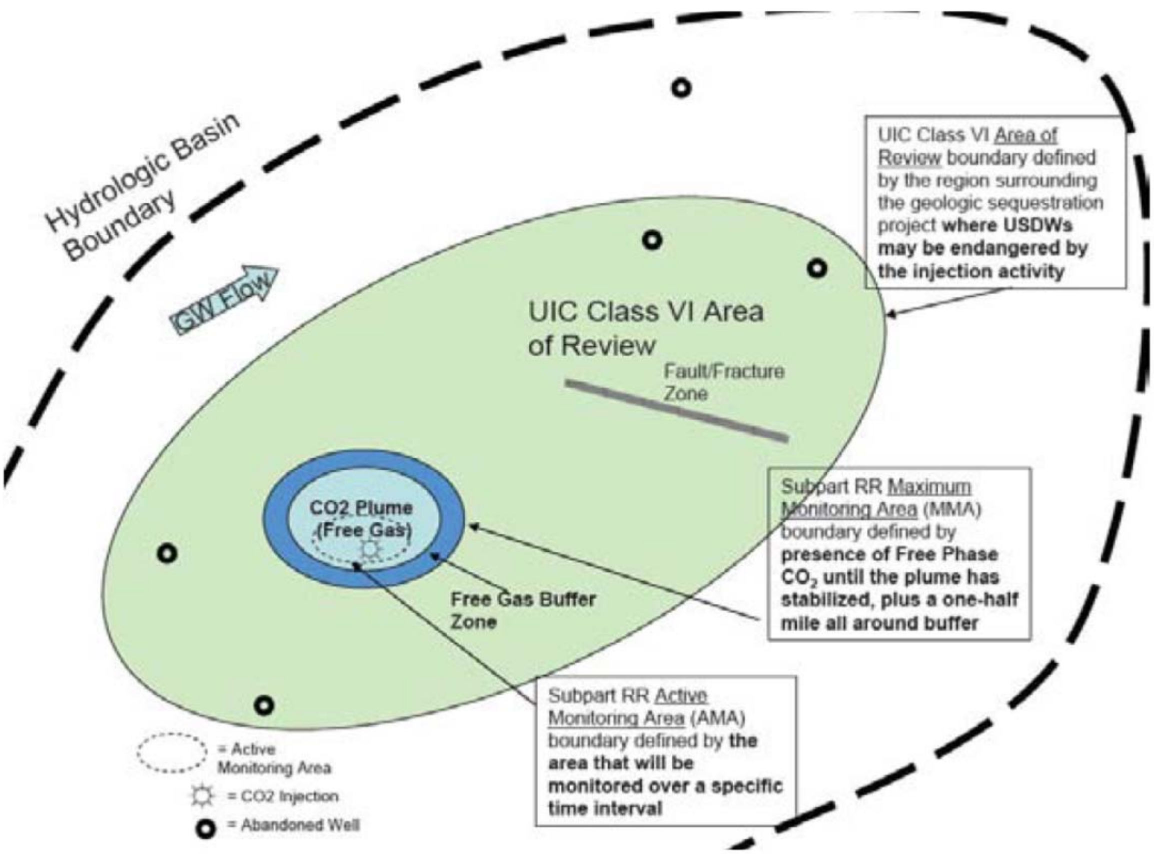
The maximum monitoring area (MMA) is the maximum areal extent of the free phase CO_2 plume over the lifetime of the project, with an all-around buffer region of at least one-half mile. This is the areas shown in dark blue in **Figure 25**. The MMA is to be calculated using modeling that is based on site characterization data and monitoring results. Reservoir simulation modeling has been used for decades in the oil and gas industry, and is used to design the development of oil/gas fields, and is currently being applied at GS sites. The geological volume occupied by the stabilized free-phase CO_2 plume[113] will be a function of the amount and rate of CO_2 injected, as well as the geologic characteristics of the Injection Zone (IZ) and Containment Zone (CZ).[114] Some uncertainty is inherent in the model output as a result of uncertainties related to the construction of the underlying governing equations, and uncertainties in the values used to represent the actual site conditions. Therefore, the minimum one-half mile buffer zone beyond the area determined by modeling is to be considered as part of the MMA. The buffer also can include potential leakage pathways, as discussed below.

The active monitoring area (AMA) is a part of the MMA, which will be actively monitored over a specific time period (as proposed by the operator, and for a period greater than one year), based on the CO_2 plume location over this time period. This area is indicated by a dashed line within the light blue area in **Figure 25**. Over the life of the project there will likely be several monitoring phases, each with an AMA that will increase in size as the plume expands. The boundaries of the AMA are established by superimposing two areas: the first is a one-half mile buffer zone around the outline of the anticipated plume location at the end of the AMA period, and the second is the area projected to contain the free-phase CO_2 plume five years after the end of the AMA. The area encompassed by either or both of the two areas will represent the AMA. The AMA boundary is expected to take into modeling uncertainties, as well as potential leakage pathways.

[113] The reporter should define what criteria will be used to determine when the free-phase plume is to be considered stable.

[114] These include the geometry, thickness, permeability, and porosity, and the amount of anisotropy within the IZ and CZ.

Figure 25 Schematic Illustrating Monitoring Areas for Subpart RR and Area of Review for Class VI UIC Permits



Source: ICF

Leakage pathways
Reporters have to identify and evaluate risks for leakage of CO_2 through all potential pathways within the MMA. Each of the pathways have to be identified, labeled, described qualitatively, and assessed for likelihood, magnitude, and timing of surface leaks from the pathways. Potential release pathways at GS sites include: wells, fractures, faults, bedding plane partings, and the competency, extent, and dip of the confining system.

Detection and Quantification Strategy
After identifying the potential leakage pathways in the MMA, the reporter will have to

design a strategy for detecting and quantifying surface leakages from the AMA within specified time intervals. The strategy needs to ensure that potential leakage pathways are monitored in a comprehensive manner such that timely and accurate identification of leaks are possible. Detection and quantification of surface leaks will likely rely on both subsurface- and surface-based monitoring and measurement techniques. Technical specifications of the detection capability of the selected monitoring system need to be described, along with an overall performance evaluation of the monitoring system.[115] The MRV plan should describe the strategy to verify and confirm the location and source of surface leakage, if one has been detected. A combination of direct measurement and estimation can then be used to quantify the amount of surface leak.

Establishing Baselines
The reporter will have to develop an approach for establishing environmental and operational baselines in order to be able to discern whether or not the results of the monitoring indicate a CO_2 leak from the injection site. A CO_2 leak could manifest itself as detectable deviations from the expected baseline values in one or more of a number of environmental conditions[116] or from expected operational conditions.[117] Hence, it is important to establish a baseline of the monitoring system (without CO_2 injection) in order to be able to identify the changes due to injection and possible leakage. Baseline monitoring is essentially the first step in implementing the leakage detection and quantification monitoring strategy. In the MRV plan, reporters should credibly explain how an expected baseline, representing the most probable range and variations of the indicator parameters, will be obtained before CO_2 injection.

Mass Balance Equation
Reporters need to describe the monitoring and calculation methodologies used for quantifying equipment leaks and vented emissions from surface equipment, and the quantity of CO_2 produced with other fluids.

6.3 Underground Injection Control Program

EPA's Underground Injection Control (UIC) program regulates underground injection of CO_2 and other fluids under the Safe Drinking Water Act (SDWA). The UIC regulations were designed to help ensure that injected fluids do not endanger underground sources of drinking water (USDWs). The regulations are implemented by state and federal regulators and well operators with expertise in relevant geological issues, well siting, well construction, well operation, and well closure.

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[115] This could state the performance as being able to detect leaks of X metric tons of CO_2 per year within Y days with a probability of Z percent.
[116] Such as subsurface pressure, groundwater chemical composition, the concentration of CO_2 in air, soil, surface or near-surface CO_2 flux rates, surface CO_2 isotope ratios, and other geophysical and geochemical parameters.
[117] Such as the injection pressure and the annular pressure in the well.

EPA issued the final rules for a new Class VI UIC injection wells for the purpose of geological storage, with the overarching goal of protecting USDWs from injection-related activities. The existing UIC rules were used in developing this rule and they were tailored specifically for CO_2 injection and geological storage. Some of the factors that were considered in developing the rules include the relative buoyancy of CO_2, its corrosivity in the presence of water, the potential presence of impurities in captured CO_2, its mobility within subsurface formations, and large injection volumes anticipated at full scale deployment.

The rule is voluntary and does not require any entity to capture and/or sequester CO_2, but only that if the entity decides to inject CO_2 for geologic sequestration (GS), then they obtain a UIC Class VI permit.

Existing injection of CO_2 for enhanced recovery (ER) of oil and gas is currently classified as Class II UIC injection wells. These wells would continue to operate under the Class II requirements, and any new wells that would be used for production of oil or gas. Class VI rules for GS would apply after the reservoir is depleted, if there are increased risks for USDWs, or if the ER operator decides to apply for GS.

The specific modifications of the Class VI UIC regulatory program for GS include:

- Site Characterization aimed at appropriate siting of injections wells.
- Definition of an Area of Review (AoR) and development of a Corrective Action Plan
- Requirements for Injection Well Construction
- Depth Waivers and Aquifer Exemptions
- Requirements for Injection Well Operation
- Comprehensive Testing and Monitoring Plans
- Well Plugging, Post-Injection Site Care, and Site Closure Plans
- Financial Responsibility
- Emergency and Remedial Response Plan
- Public Involvement

The above issues are briefly described below. The UIC Class VI permit is valid for the entire lifecycle of the GS project, including the post-injection site care period. Throughout the project life, owners/operators are required to review and update the AoR and corrective action plan, testing and monitoring plan, and emergency and remedial response plan. The UIC permits are for individual wells, rather than an area permit to ensure that each well is addressed individually.

The EPA has also developed a cost-benefit analysis of the new Class VI permit, including different regulatory alternatives. This analysis was carried out on a “baseline” of existing or planned GS projects only to evaluate the cost of regulatory alternatives and was not intended to evaluate the regulatory impact on GS under potential greenhouse gas reduction legislation.

Site Characterization

Geologic site characterization is necessary to ensure that GS wells are appropriately sited. Owners/operators of Class VI wells need to submit a detailed assessment of the geologic, hydrogeologic, geochemical, and geomechanical properties of the proposed GS site to ensure that GS wells are sited in appropriate locations and injected into suitable formations. Owners/operators need to demonstrate that:

- The geologic system contains an injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream,
- The confining zone(s) is free of transmissive faults or fractures and,
- The confining zone is of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).

Some of the key requirements include the submission of the following:

- A map showing the injection well for which the permit is sought for, and applicable area of review (see below). The area of review needs to indicate all other wells and relevant features.
- Information on geological and hydrogeological properties of the storage site and overlying formations.
- A tabulation of all wells that penetrate the injection or confining zones.
- Maps and stratigraphic cross sections indicating vertical and lateral limits of all USDWs in the area of review.
- Baseline geochemical data for the proposed site.
- Proposed operational data for the site, including injection rates and volumes, injection pressure, source of CO_2 stream, and analysis of the chemical and physical characteristics of the stream.

The data and information collected during the site characterization phase is expected to be used for Area of Review delineation, development of construction and operation plans, and for establishing baseline monitoring.

Area of Review and Corrective Action

The existing UIC injection rules require that the owners/operators define an Area of Review (AoR), within which they must identify artificial penetrations (regardless of property ownership) and determine whether they have been properly completed or plugged. Similarly, for the Class VI wells, determining the AoR is an important part of ensuring that there are no features near an injection well (such as faults, fractures, or artificial penetrations) where injected fluid could move into a USDW or displace native fluids into USDWs. The AoR is defined as “the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The AoR is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected CO_2 stream and displaced fluids and is based on available site characterization, monitoring, and operational data."

Based on the evaluation of all penetrations in the AoR, the owner/operator needs to develop a corrective action plan to prevent the movement of CO_2 or other fluids into or between USDWs. Any deficiency in wells that are potentially conduits for CO_2 will need to be corrected (regardless of ownership). Such corrective actions can be undertaken in a phased manner during the lifetime of the project, such that the wells are corrected well in advance of the anticipated arrival of the CO_2 plume or pressure front.

Requirements for Injection Well Construction

The Class VI injection well needs to be constructed of materials that can withstand contact with CO_2 over the life of the GS project. Proper construction entails many layers of protection to ensure that fluids do not flow into USDWs. EPA has developed specific requirements for surface and long-string casings, cement and well materials, and tubing and packers for Class VI wells. The wells also need to have automatic shutoff systems to prevent fluid movement into unintended zones.

Depth Waivers and Aquifer Exemptions

The Class VI rule specifically states that any injection of CO_2 needs to be in formations that are below the lowest USDW. In some cases, this depth requirement may prevent GS in saline reservoirs that are in between deep USDWs. Therefore, the Class VI rule allows for owners/operators to seek a waiver of this depth rule on a case by case basis to allow for injection of CO_2 into non-USDW formations above and/or between USDWs, as long as these USDWs are protected.

In limited circumstances, owners/operators may also seek an exemption to inject CO_2 into formation containing USDWs. If such an exemption is granted, the USDW will be removed from the SDWA protection.

Requirements for Injection Well Operation

In addition to standard requirements for injection well operations, Class VI wells have injection pressure limitations, use of down-hole shut-off systems, and annulus pressure requirements to ensure that injection of CO_2 does not endanger USDWs. Injection pressure needs to be limited to a maximum of 90% of fracture pressure of the injection zone. Owners/operators need to install and use alarms and automatic shut-off systems in the well tubing, in addition to surface shut-off devices, to prevent well complications such as well backflows. Annulus pressure needs to be at a higher pressure than the operating pressure and filled with non-corrosive fluids, unless the Director determines that such a requirement might harm the integrity of the well or endanger USDWs.

Comprehensive Testing and Monitoring Plans

Owners/operators need to develop and implement a comprehensive testing and monitoring plan including: a) CO_2 stream analysis, b) monitoring of corrosion of the well's tubular, mechanical and cement components, c) pressure fall-off tests, d) ground water quality testing, e) geochemical monitoring, f) CO_2 plume and pressure front tracking, and g) surface air and soil gas monitoring (at EPA discretion). A mechanical integrity test (MIT) needs to be routinely conducted as well.

Well Plugging, Post-Injection Site Care and Site Closure Plans

Following the cessation of injection, owners/operators need to plug injection and monitoring wells such that USDWs are not endangered. Extended post-comprehensive monitoring is needed until it is demonstrated that the CO_2 plume and pressure front movement no longer pose any danger to USDWs. There is a default of 50 years of post-injection site care (PISC), in which the site will be periodically monitored to track the position of the CO_2 plume and pressure front. There is some flexibility on the timeframe if the owner/operator can demonstrate that there is no danger to USDWs before the 50 year time period. Once it has been demonstrated that a site will no longer pose any danger to USDWs, the site can be closed, similar to other well classes, based on the approved PISC and site closure plan. The owner/operator will need to develop PISC and site closure plans for approval by the EPA. Following closure, the operator will submit a closure report to the EPA. After the closure report is accepted by the EPA, the owner/operator will no longer be subject to enforcement under the SDWA, unless there is regulatory non-compliance such as providing erroneous data, fraud, etc. The owner/operator will be liable for any fluid migration that may affect human health and USDWs, even after site closure.

Emergency and Remedial Response Plan

Owners/operators need to develop and maintain an emergency and remedial response plan, describing actions to be taken if USDWs are endangered during construction, operator, and PISC periods. The plans needs to be site-specific and risk-based, and EPA will evaluate the plan based on all of the information submitted under the permit application.

Financial Responsibility

Owners/operators need to demonstrate that they have the financial resources to conduct corrective actions in the AoR, injection well plugging, PISC, site closure, and emergency and remedial actions. Maintaining and demonstrating financial responsibility for the site will allow for GS injection sites to be cared for and maintained appropriately throughout the lifecycle of a GS project. EPA has described the different instruments that could be used to demonstrate financial responsibility. The instruments need to have protective conditions of coverage. Owners/operators have the flexibility to choose different instruments.

The amount of financial responsibility to be maintained will be determined by a detailed separate written estimate (in current dollars) for the cost of performing the corrective actions in the AoR, plugging of injection wells, PISC, site closure, and emergency and remedial actions. An annual inflationary update is to be submitted, along with adjustments to the cost estimates.

The EPA has noted that under the SDWA, it does not have the authority to transfer liability from one entity to another, and hence long-term liability remains with the owner/operator under the SDWA, even after site closure. Such long term liability transfers (based on performance criteria) may, however, be possible under state laws.

Public Involvement

UIC injection permits have public participation requirements as part of the permitting process, and the Class VI permit process adopts this existing process. EPA encourages owners/operators and permitting agencies to involve the public by providing them information about the Class VI permit as early in the process as possible. EPA expects a higher level of public interest in GS projects, and hence early public participation will allow the public to get a better understanding of the GS project, its technology, benefits, and safety. Permitting authorities must provide public notice of pending actions via newspaper advertisements, postings, mailings, or e-mails to interested parties; hold public hearings if requested; solicit and respond to public comment; and involve a broad range of stakeholders. Social media can also be used for this process.

In addition to the general public, Class VI notices must also be provided to state and local oil and gas regulatory agencies, State agencies regulating mineral exploration and recovery, the Director of the Public Water System Supervision program in the state, and all agencies that have jurisdiction to oversee wells in the state.

6.4 RCRA/CERCLA Exemptions for GS

The UIC Class VI requirements do not specifically state whether CO_2 streams are considered hazardous under the Resource Conservation and Recovery Act (RCRA) subtitle C. Subtitle C of RCRA establishes a ''cradle to grave'' regulatory scheme over certain hazardous solid wastes. While there may be components of a CO_2 stream that could potentially be considered hazardous, the CO_2 stream itself is not listed as a RCRA hazardous waste. Hence, there is some uncertainty as to the applicability of RCRA subtitle C requirements for CO_2 streams.

EPA is now considering a proposed rule under RCRA to explore a number of options, including a conditional exemption from the RCRA requirements for hazardous CO_2 streams, in order to facilitate implementation of GS, while protecting human health and the environment.

CERCLA, more commonly known as Superfund, is the law that provides broad Federal authority to clean up releases or threatened releases of hazardous substances that may endanger human health or the environment. CERCLA authorizes EPA to clean up sites contaminated with hazardous substances and seek compensation from responsible parties or compel responsible parties to perform cleanups themselves.

CO_2 itself is not listed as a hazardous substance under CERCLA. However, the CO_2 stream may contain a listed hazardous substance (such as mercury) or may mobilize substances in the subsurface that could react with ground water to produce listed hazardous substances (such as sulfuric acid). The composition of the specific CO_2 stream and geochemical interactions will determine whether CERCLA listed substances result.

CERCLA exempts from liability certain ''Federally permitted releases'' (FPR), which would include the permitted CO_2 stream, as long as it is injected and behaves in accordance with the Class VI permit requirements. The Class VI permits will need to be carefully structured to ensure that they prevent potential releases from the well, which are outside the scope of the Class VI permit and thus not considered federally permitted releases.

6.5 Vulnerability Evaluation Framework

The EPA has developed a Vulnerability Evaluation Framework (VEF) to systematically identify those conditions that could increase the potential for adverse impacts from GS.[118] The VEF provides policy-makers, stakeholders, industry, and the public with a framework to evaluate vulnerabilities associated with GS systems.

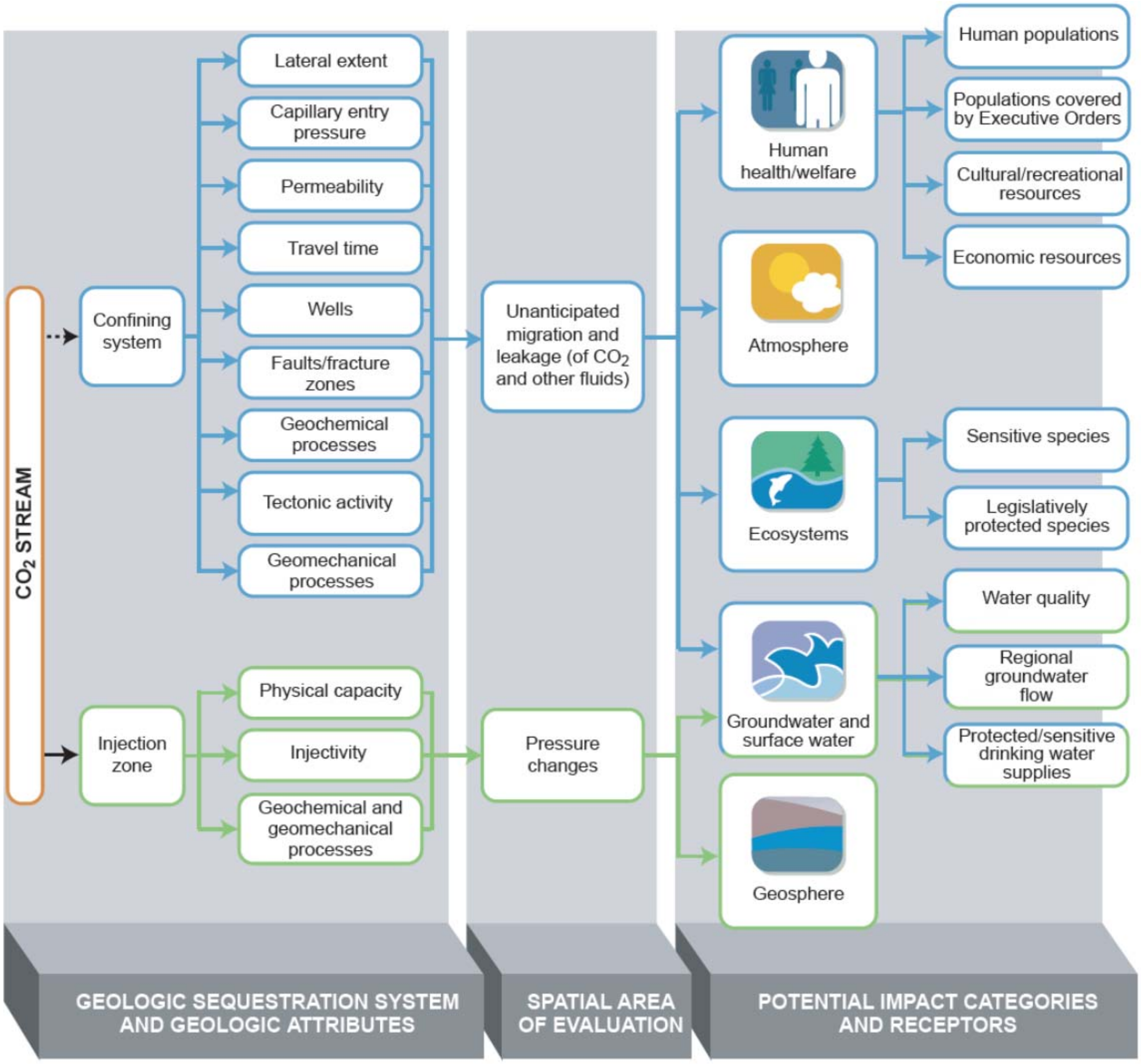
The VEF, which is based on a review of available GS literature, applicable technical knowledge, and consultation with experts, can be applied to:

- Support the GS rulemaking (particularly the UIC Class VI injection rules)
- Assist permitting authorities in identifying data needs, monitoring, mitigation and verification requirements, and ultimately assist in determining site suitability, and
- Provide transparency in assessing vulnerabilities, which will help communicate potential risks and risk reduction strategies to the public.

The conceptual model in the VEF for evaluating risks and impacts is shown in **Figure 26**.

[118] EPA, 2008, "Vulnerability Evaluation Framework for Geologic Sequestration of Carbon Dioxide," July 2008, http://www.epa.gov/climatechange/emissions/downloads/VEF-Technical_Document_072408.pdf.

Figure 26 Conceptual Risks and Impact Model



Source: EPA Vulnerability Evaluation Framework, 2008

7. Modeling Framework and Assumptions

This purpose of this chapter is to summarize the power sector implementation using ICF's IPM® model, which was used in the analysis, and the significant assumptions underlying the study.

7.1 IPM® Model

IPM® is ICF's multi-regional, dynamic, linear programming model of the North American electric power sector including all major generators. It includes a comprehensive capability for coal, natural gas, and biomass supply and demand. The model is a multi-regional, deterministic, dynamic linear programming model with so-called perfect foresight. It uses a production costing model to determine the least cost solution to meet electric generation energy and capacity requirements, subject to environmental, transmission, fuel, reserve margin, and other system operating constraints. IPM® has evolved over 30 years after millions of dollars in development costs, and has a core group of modelers who update the tool on a continuous basis.

ICF used the US EPA's v4.10 Base Case using IPM as the starting point for the modeling for BOEM,[119] along with updates from selected assumptions from Energy Information Administration's Annual Energy Output (AEO) 2011. The BOEM cases however, have the addition of a national CO_2 policy to incentivize CCS, so that the analysis of offshore CCS can be carried out. The appropriate AEO 2011 scenario used to develop assumptions is the AEO 2011 GHG Price Economywide Case. This report section summarizes the assumptions used by ICF for the BOEM modeling.

7.2 Run Year and Model Region Definitions

IPM® has a year-mapping feature that enables relatively fast simulations of long-time horizons, so that not every individual year has to be run in the model. Several years in the time horizon can be mapped into specific single run years.

While the model makes decisions only for run years, information on non-run years can be captured by mapping run years to the individual years they represent. Generation costs for all years that are mapped to the specified run year are computed, and are included in the objective function. Run years are usually chosen to be the middle year of the mapped years, and are influenced by policy start dates. Five run years are selected for the BOEM study, as shown in **Table 13**. Each year is modeled with two

[119] Detailed documentation for the US EPA v4.10 Base Case assumptions is available at: http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev410.html.

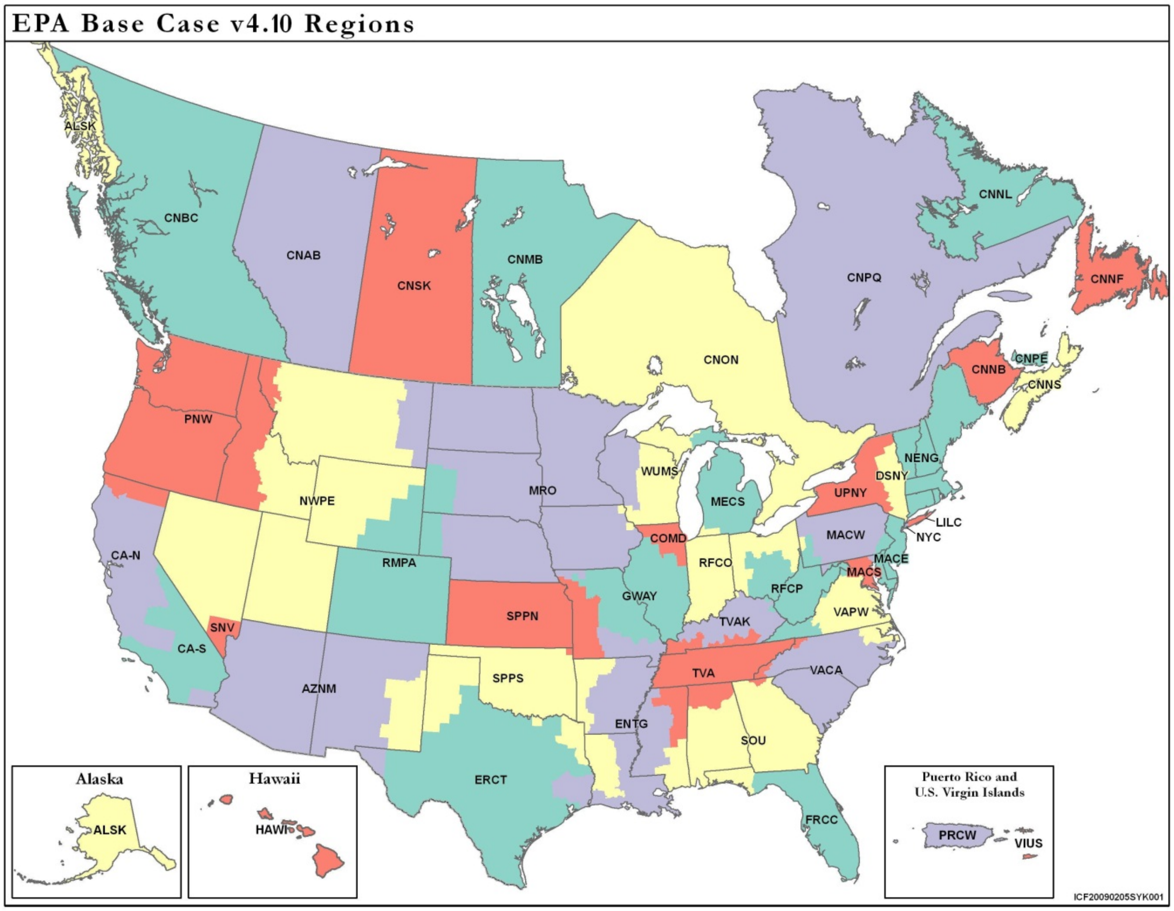
seasons: Winter (October-April) and Summer (May-September), such that demand and availability will be defined on a seasonal basis.

Table 13 Run Year Mapping in IPM

Run Year	Years Mapped
2015	2014-2016
2020	2017-2024
2030	2025-2034
2040	2035-2045
2050	2046-2054

IPM® Model regions are defined such that transmission bottlenecks are captured, while being consistent with primary data sources, and NERC region and sub regions. As in the EPA Base Case v.4.10, the BOEM study includes 32 model regions in the USA and 11 model regions in Canada, with the US and Canadian power sector as an integrated network (**Figure 27**). The revisions related to AEO 2011 assumptions will only be implemented in the US model regions.

Figure 27 Model Regions in IPM



Source: EPA Base Case documentation.

7.3 Market Assumptions

Demand at each model region level is determined by a combination of the following variables:

- Peak Demand, which is the maximum power load (MW) requirement for a model region;
- Energy Demand, which is the total energy requirement (MWh) for a model region, defined on an annual basis; and
- Hourly Load Profiles, which are shapes of the hourly demand curve, defined for 8,760 hours for a given year. The profiles are defined for each model region, and are scaled to meet the peak and energy demand. Hourly load files in IPM® are created from the historical load data filed by each region's utilities (FERC Form 714) for a normal weather year.

The EPA Base Case v4.10 uses the electricity demand assumptions from AEO 2010 Reference Case. For the BOEM, the electricity demand assumptions were updated to the AEO 2011 GHG Economywide Case, which reflects an average annual growth in U.S. electricity demand of 0.24% over the 2012 to 2035 timeframe.[120] The EPA Base Case v.4.10 uses the year 2007 as the "normal weather year" for all IPM® regions.

To maintain system stability and reliability, each IPM® model region must have a certain amount of backup capacity ("reserve margin") relative to its projected peak demand. The reserve margin is defined as the amount of capacity that needs to be built over and above the peak load. Transmission between model regions allows for reserve sharing (and consequent broad price equilibration) across the North American grid. The reserve margin and transmission interconnect assumptions between different model regions in the BOEM study are maintained at the EPA Base Case v4.10 levels.

7.4 Financial Assumptions

IPM® is a linear programming model that optimizes system performance in a least cost manner to meet market and policy requirements in the analysis. All costs in the model are represented in real 2007 dollars, and are then discounted back on a present value basis to determine the least cost way to meet the market and policy requirements defined.

The discount rate is important in evaluating the tradeoffs of making investments and incurring costs in the near-term vs. incurring expenses over the longer-term. The discount rate for BOEM modeling is the same as the EPA Base Case v4.10, and is 6.15% across all technologies.

New capital investments[121] in IPM® are annualized using a capital charge rate that takes into account the amount of debt and equity and their respective rates, taxes, depreciation schedule, book life and debt life. Capital charge rates assigned to each technology type are based on a technology-specific discount rate (See **Table 14**), and are identical to the EPA Base Case v4.10.[122]

[120] Note that in the AEO 2011 Reference Case, the average annual growth in U.S. electricity demand is 0.78% over the 2012 to 2035 time frame.
[121] Note that the capital cost of existing and planned/committed generating units and the emission controls already on these units are considered "sunk costs" and are not represented in the model.
[122] Within the IPM model there is only one discount rate. The discount rates for different technology are consistent with the risk profiles of the various technologies, and are only used for capital charge rate calculations.

Table 14 U.S. Discount Rates and Capital Charge Rates

EPA Base Case v4.10

Investment Technology	Capital Charge Rate	Discount Rate	Book Life
Environmental Retrofits	11.3%	5.5%	30
Advanced Combined Cycle	12.1%	6.2%	30
Advanced Combustion Turbine	12.9%	6.9%	30
Supercritical Pulverized Coal and Integrated Gasification Combined Cycle without Carbon Capture[1]	14.1%	7.8%	40
Advanced Coal with Carbon Capture	11.1%	5.5%	40
Nuclear without Production Tax Credit (PTC)	10.8%	5.5%	40
Nuclear with Production Tax Credit (PTC) [2]	9.1%	5.5%	40
Biomass with ARRA Loan Guarantees[3]	9.3%	4.6%	40
Biomass without ARRA Loan Guarantees	11.1%	6.2%	40
Wind and Landfill Gas with ARRA Loan Guarantees[3]	10.1%	4.6%	20
Wind and Landfill Gas without ARRA Loan Guarantees	12.2%	6.2%	20
Solar and Geothermal with ARRA Loan Guarantees[3]	10.1%	4.6%	20
Solar and Geothermal without ARRA Loan Guarantees	12.2%	6.2%	20

Notes:

The discount rates appearing in the table were used in deriving these capital charge rates. However a single U.S. discount rate of 6.15% is used across all technologies in EPA Base Case v.4.10.

[1]The capital charge rate for these technologies includes a 3% climate change uncertainty adder.

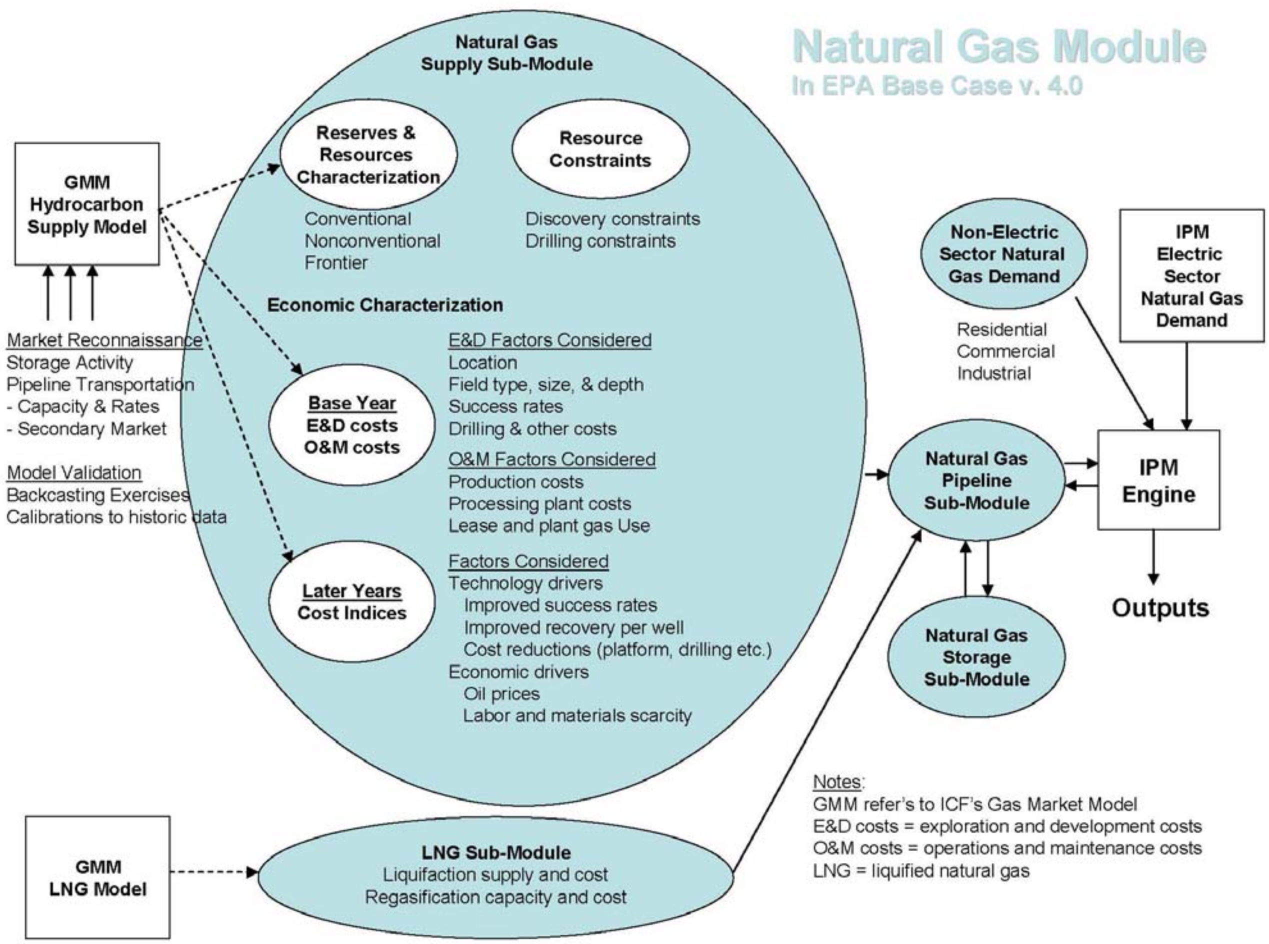
[2]The capital charge rate for this technology reflects the impact of the PTC provided under the Energy Policy Act of 2005.

[3]The capital charge rate for these technologies reflects the impact of ARRA loan guarantees.

7.5 Fuel Market Assumptions

As with the EPA Base Case v4.10, the IPM® based model for BOEM takes advantage of the embedded comprehensive natural gas supply, demand, storage and pipeline model within IPM® modeling framework. In this system, natural gas supply curves are generated endogenously for each region, and the balance between the natural gas supply and demand is solved in all regions simultaneously. The direct interaction between the electric and the gas modules captures the overall gas supply and demand dynamic and requires no iteration **(Figure 28)**.

Figure 28 Schematic of Natural Gas Module in IPM



Source: EPA Base using documentation.

The gas model was slightly revised to capture the AEO 2011 crude oil price projections, which are shown in **Table 15** below.

Table 15 Price Projections of Imported Low Sulfur Crude from AEO 2011 in 2010 Dollars per Barrel and per MMBtu

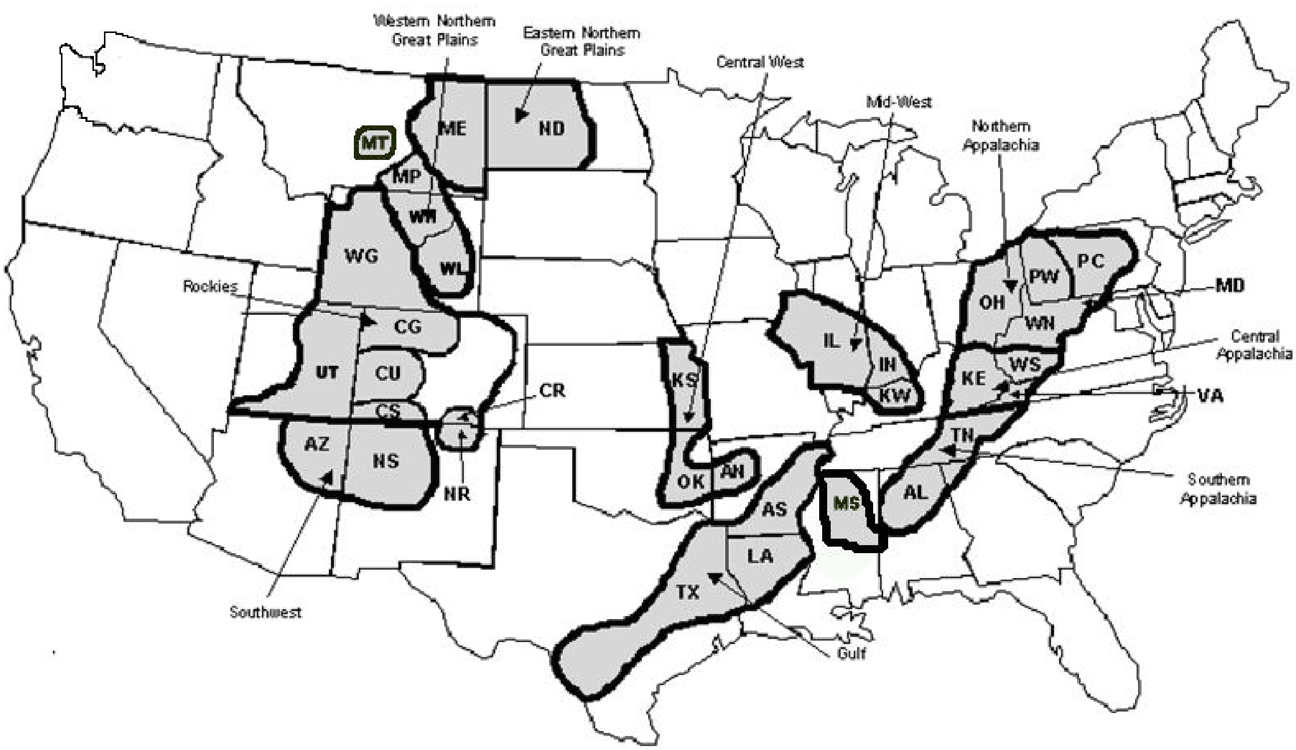
Year	GHG Econonomywide Case	
	$/bbl	$/MMBtu
2010	78.78	13.58
2011	84.01	14.48
2012	86.61	14.93
2013	88.49	15.26
2014	91.57	15.79
2015	94.68	16.32
2016	97.84	16.87
2017	100.83	17.38
2018	103.44	17.83
2019	105.96	18.27
2020	108.26	18.67
2021	110.03	18.97
2022	111.82	19.28
2023	113.38	19.55
2024	114.96	19.82
2025	116.39	20.07
2026	117.50	20.26
2027	117.93	20.33
2028	119.03	20.52
2029	119.82	20.66
2030	120.32	20.74
2031	121.03	20.87
2032	121.53	20.95
2033	121.78	21.00
2034	122.02	21.04
2035	121.96	21.03

For simulating the coal supply, the EPA Base Case v4.10 relies on a supply curve structure that allows the model to simulate the price changes that would occur with substantial shifts in demand that might occur under different environmental policies. These curves are based on the only publicly available data that are in a suitable format for use in IPM. Data for coal resources are divided into 34 coal supply basins (see **Figure 29**), and are disaggregated by the following characteristics:

- Rank (Bituminous, Subbituminous, Lignite)
- Sulfur content ranges
- Existing and new mines

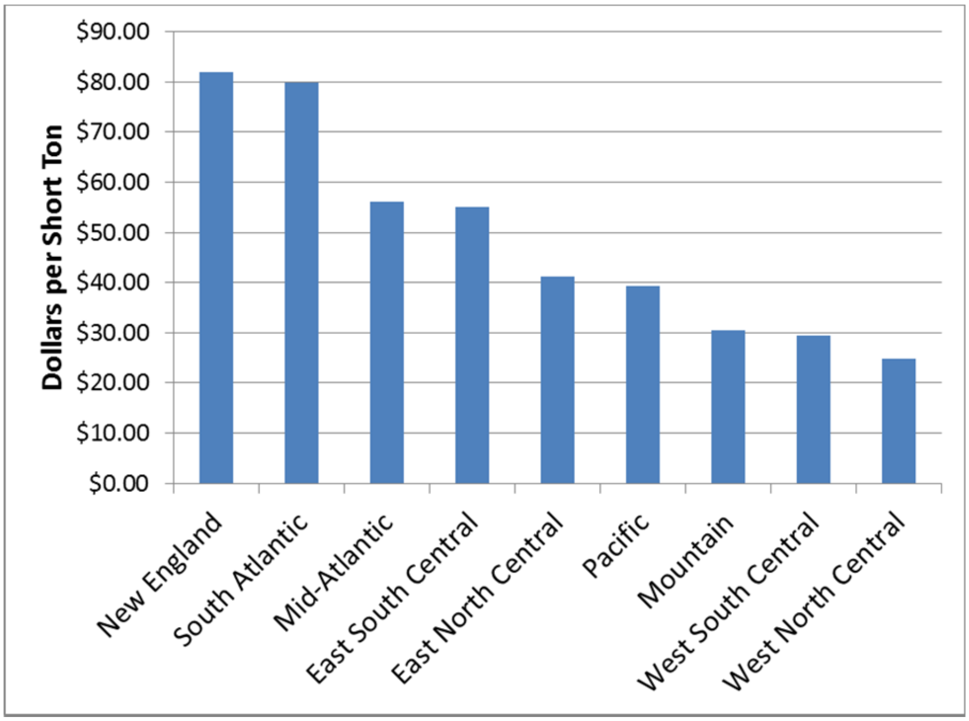
Coal plants in IPM® are assigned to one of 100+ different coal demand regions, and a coal transportation matrix links supply and demand regions in IPM®. The model then determines the least cost means to meet power demand for coal as part of an integrated optimal solution for power, fuel, and emission markets.

Figure 29 Coal Supply Basins in IPM



Figures 30 shows the 2010 price of coal delivered to the power sector by U.S. Census region.[123] New England has the highest delivered coal prices, followed by the Mid- and South-Atlantic states. Texas and Louisiana are in the West South Central region which has relatively low prices.

Figure 30 2010 Prices of Coal Delivered to Electric Power Sector



Similar to the coal curves, supply curves are also developed for biomass in IPM® based on AEO 2010 biomass supply curves for a) urban wood waste and mill residue, b) energy crop, c) forestry residue, and d) agricultural residue. The biomass supply curves are defined for the 14 NEMS coal demand regions, which are then mapped on to the EPA Base Case using IPM® model regions. The biomass supply satisfies biomass demand for the electric power and the cellulosic ethanol sectors. Biomass will be modeled as having a net-zero CO_2 emission factor. This is a common assumption used in power sector modeling and reflects the life cycle emissions over the biomass materials' growth cycle and ultimate combustion.

[123] Energy Information Administration, 2010 Coal Annual, http://www.eia.gov/coal/annual/pdf/acr.pdf.

7.6 Power Supply in IPM

The supply of electricity in IPM® is defined by a combination of the following options:

- Existing Capacity – The generating capacity currently available to the grid;
- Firmly Planned Capacity – The generating capacity that is firmly planned to be built; and
- New Build Cost and Performance – The specifications for new potential capacity types, including assumptions about technology improvement over time and resource potential.

Existing supply is captured in the IPM® model with detailed information on all existing and planned and committed grid-connected electric generators and boilers in the continental U.S.

The database used for the BOEM study is based on EPA's National Electric Energy Data System (NEEDS). The NEEDS database contains the generation unit records used to construct the "model" plants that represent existing and planned/committed units in EPA modeling applications of IPM. NEEDS includes basic geographic, operating, air emissions, and other data on these generating units.

Existing and planned committed units in the database, with the exception of nuclear units, are not provided with a specific retirement year. However, IPM® can endogenously retire power plants based on economics. The life extension cost estimates are based on the assumptions in EPA Base Case v4.10. All nuclear units are assumed to receive a license renewal at age 40, and retire at age 60.

For new builds, the performance and unit cost assumptions from conventional technologies are based on the AEO 2011. For comparison, the AEO 2011 and EPA Base Case v4.10 performance and unit cost assumptions are shown in **Table 16**.

The minor differences between the AEO and EPA cases generally result from differences in base years and escalation factors.

Table 16 Performance and Cost Characteristics for New Units

	Advanced Combined Cycle	Advanced Combustion Turbine	Nuclear	CO_2 Capture Options: Integrated Gasification Combined Cycle – Bituminous	CO_2 Capture Options: Advanced Coal with Carbon Capture-Bituminous	Supercritical Pulverized Coal – Wet Bituminous
AEO 2011						
Heat Rate (Btu/kWh)	6,430	9,750	10,453	8,700	10,700	8,800
Capital (2010$/kW)	1000	664	5325	3213	5337	2836
Fixed O&M (2010$/kW/yr)	14.6	14.7	88.5	59.0	69.1	29.6
Variable O&M (2010$/MWh)	3.10	6.96	2.02	6.85	8.91	4.24
EPA Base Case v4.10						
Heat Rate (Btu/kWh)	6,810	10,720	10,400	8,424	10,149	8,874
Capital (2010$/kW)	1016	727	4811	3399	4914	3038
Fixed O&M (2010$/kW/yr)	15.0	12.8	96.2	49.9	63.0	30.1
Variable O&M (2007$/MWh)	2.68	3.74	0.80	1.37	1.74	3.57

7.7 Air Regulatory Policies

The modeling for BOEM will incorporate several different federal and state level regulations for SO_2, NO_x and mercury emissions from power plants. In 2004-2005, EPA promulgated the Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR) and the Clean Air Visibility Rule (CAVR) to control SO_2, NO_x and mercury emissions from the power sector. Subsequently, CAIR and CAMR have been vacated by the courts. Recently, EPA promulgated the Cross-State Air Pollution Rule (CSAPR) and is in the process of promulgating a draft Toxics Rule as replacement regulations to reduce SO_2, NO_x and mercury emissions from power plants. The Toxics Rule is not yet finalized, and therefore, for the BOEM study, it is proposed that only the Cross State Air Pollution Rule, NO_x State Implementation Plan (SIP) Call and the Title IV SO_2 regulations be modeled.

None of the regulations above specifically address CO_2 emissions from power plants at a national level.

7.8 Emission Control Technologies and Retrofit

Within the IPM® framework, units affected by EPA's air emissions regulations can comply by: a) fuel-switching, b) buying allowances (if the policy is market-based), c) reducing dispatch/shutting down, or d) installing emissions control technologies.
In the EPA Base Case v4.10, IPM® explicitly models the most common existing control technologies, each of which impact the emissions rate for SO_2, NO_X, mercury, and CO_2 emissions. Emission reduction factors are applied to the input content of the fuel to reflect the combination of controls used in any particular plant. A list of control technologies is shown in **Table 17**.

Table 17 Table of Control Technologies

Pollutant	Technology
SO_2	Wet Scrubber, Dry Scrubber, Dry Sorbent Injection
NO_x	SCR, SNCR
Mercury	ACI
CO_2	Carbon Capture and Storage, Biomass Cofiring, Coal to Gas conversion

Retrofit costs for carbon capture and storage (CCS) are shown in **Table 18** based on EPA Base Case v4.10 CCS retrofit assumptions. The option to retrofit CCS technology will be provided only to existing coal boilers larger than 400 MW.

Table 18 Retrofit Assumptions for Carbon Capture

Applicability (Original MW Size)	450-750 MW	> 750 MW
Incremental[1] Capital Cost (2010 $/kW)	2,053	1,665
Incremental[1] Fixed O&M (2010 $/kW-yr)	3.12	2.06
Incremental[1] Variable O&M (2010 (mills/kWh)	2.45	2.45
Capacity Penalty (%)	-25%	-25%
Heat Rate Penalty (%)	33%	33%
CO_2 Removal (%)	90%	90%
Note: [1] Incremental costs are applied to the derated (after retrofit) MW size.		

7.9 CO_2 Allowance Prices and CCS Modeling

Currently, there are no national-level CO_2 emission-reduction policies in the US. Hence, the EPA Base Case v4.10 does not model a national-level CO_2 emission reduction policy. However, given that BOEM would like to analyze the costs and benefits of CO_2 storage in the OCS, economic modeling needs to include a hypothetical CO_2 emission reduction policy. A generic CO_2 policy based on the AEO 2011 GHG Price Economywide Case is modeled in the BOEM No-OCS Case. In this case, an economy-wide CO_2 allowance price will be set at \$28 per metric ton CO_2 in 2015 and it rises to \$75 per metric ton CO_2 in 2035 (in 2009 dollars). The growth rate of the allowance price during the 2013-2035 period is used to extend the projection to 2050. The AEO has not made any assumptions in regards to offsets, bonus allowances for CCS, or specific allocation of allowances in the GHG Price Economywide Case and these are not needed to run IPM® with a fixed allowance price. **Table 19** shows the expected allowance price through 2050.

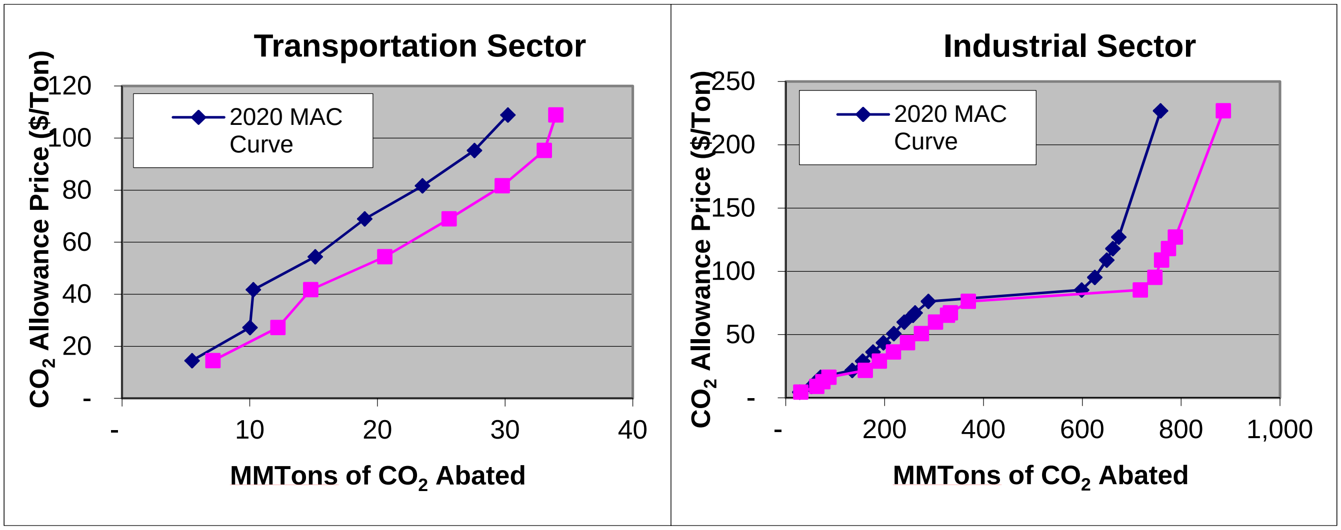
Table 19 Assumed CO_2 Allowance Price for Study

	2015	2020	2030	2040	2050
CO_2 Allowance Price (2010\$/Ton)	25	32	54	91	152

The CO_2 allowance prices in the table translate into an increase in retail electricity rates of about \$16.25 to \$99.00 per megawatt-hour. The 2015 price equates to approximately 1.6 cents per kilowatt-hour. Current retail rates are approximately 10 to 11 cents per kilowatt-hour.

The non-power sector related CO_2 emissions reductions under the CO_2 allowance prices from the transportation and industrial sectors can be estimated using the marginal abatement cost (MAC) curves in **Figure 31**. The MAC curves represent technical costs and emissions reduction potential of the abatement options. These curves were developed in 2009 and are national in scope.

Figure 31 Illustrative MAC Curves for Non-Power Sectors



In order to model the transportation and storage aspects of CCS, coal power plants with CO_2 capture capability are grouped into CO_2 production regions, and CO_2 storage sites are grouped into CO_2 storage regions. The production and storage regions are then interconnected by a CO_2 transportation network. The network capacity is modeled to be unlimited in the long run and it is available at a constant unit cost of transportation between any given capture region and any given storage region. The costs shown in section 5.3 of this report (e.g., $ 4.61 per ton to transport 150 miles) are the basis for these transport costs in the model. The geologic storage cost for CO_2 in each CO_2 storage region is characterized by a storage cost curve. Storage regions with enhanced oil recovery possibilities have negative costs and represent the lower end of the geologic storage cost curve.

The No-OCS Case for BOEM study does not allow for CCS in the OCS while the OCS Case assumes that CCS on the OCS is permitted.

7.10 Generation Capacity Deployment Constraints

Generation capacity deployment constraints for the more capital intensive generation technologies and retrofits (new nuclear, advanced coal with carbon capture, and carbon capture retrofits) are typically incorporated into IPM® modeling, in order to place an upper bound on the amount of these technologies that can be built in any given model run year over the modeling time horizon.

The upper bound is intended to capture limiting factors such as: production capacity limitations related to capacity of firms to undertake multiple projects in parallel; general limitations in the domestic infrastructure for heavy manufacturing; financial limitations related to obtaining financing simultaneously for several projects at an acceptable level of risk; and workforce limitations.

These capacity deployment constraints are based on assessments of historical trends and projections of capability going forward.

EPA Base Case v4.10 has a joint capacity deployment constraint on advanced coal with CCS and new nuclear (see **Figure 32**, as well as a separate capacity deployment constraint on new nuclear only in **Table 20**). As shown in **Table 20** and the accompanying chart, if new nuclear deployment starts in 2030 (blue line in bar chart), the maximum new nuclear capacity by 2050 would be about 242,000 megawatts.

CCS is expected to start only in 2015 with an upper limit of 2 GW, and the upper limit progressively grows to nearly 300 GW by 2050.

Figure 32 Joint CCS and New Nuclear Capacity Constraints

Run Year	Advanced Coal with CCS (MW)	New Nuclear (MW)
2012	0	0
2015	2,000	0
2020	9,750	7,500
2030	38,220	29,400
2040	112,367	86,436
2050	293,652	225,886

Notes:
The 2020 through 2050 limits for Advanced Coal with CCS and New Nuclear technologies are a joint constraint, with the maximum amount of possible development for each technology shown by run year. If the maximum amount of one technology is developed in a given run year, zero MW of the other may be developed. See the production possibility chart below.

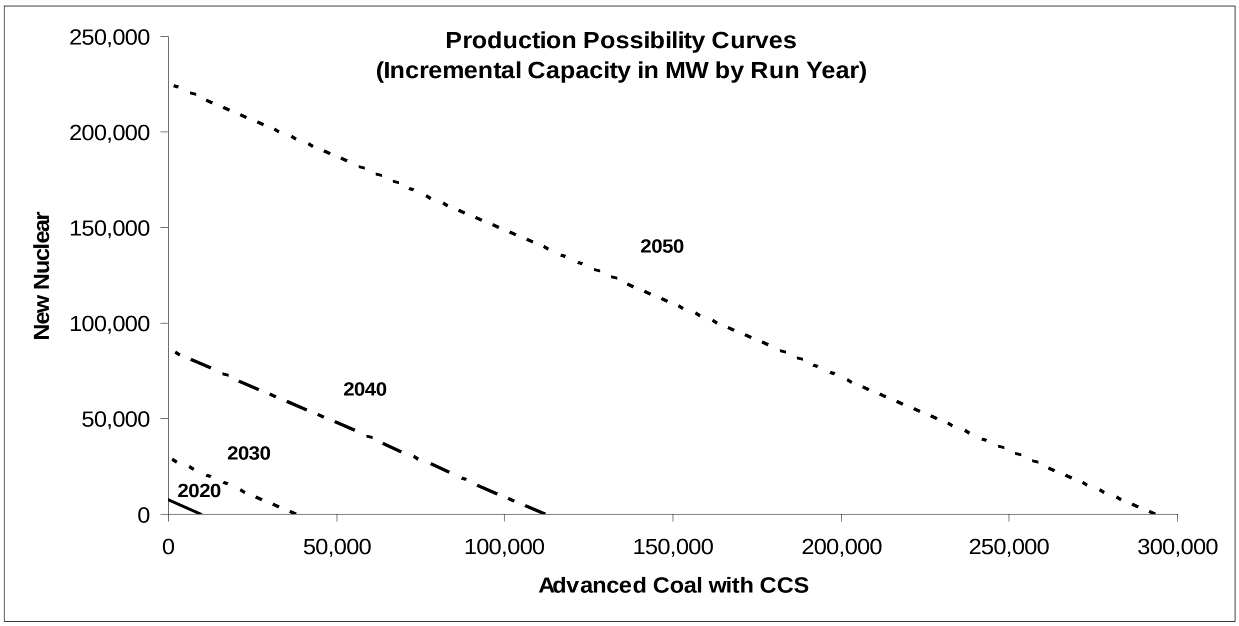
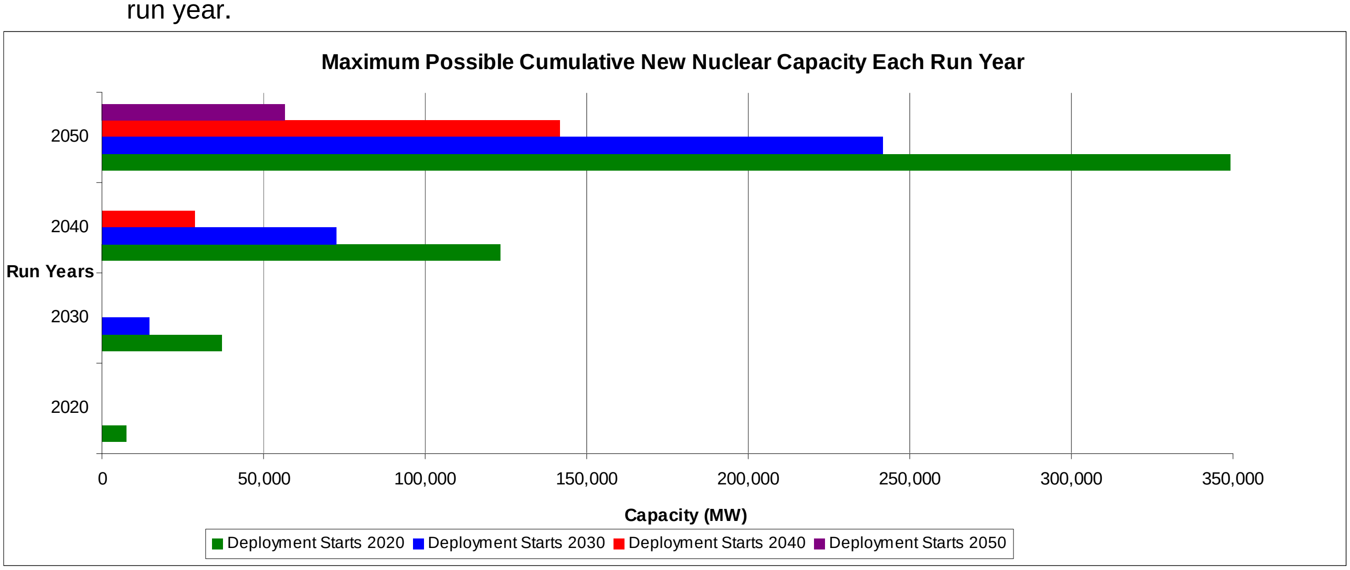


Table 20 Capacity Constraints on New Nuclear Capacity

Run Year	Base New Nuclear Capacity	Base New Nuclear Capacity Deployment Equation	*Possible* Additional New Nuclear Capacity Deployment Equation[1]	Maximum Annual Incremental New Nuclear Capacity Deployment Allowed Equation
2020	7,500	7,500	0	7,500
2030	14,700	1.96 * *2020_Base_Capacity*	+ 1.96 * *2020_Incremental_Capacity*	= 1.96 * (*2020_Base_Capacity* + *2020_Incremental_Capacity*)
2040	28,812	1.96 * *2030_Base_Capacity*	+ 1.96 * *2030_Incremental_Capacity*	= 1.96 * (*2030_Base_Capacity* + *2030_Incremental_Capacity*)
2050	56,472	1.96 * *2040_Base_Capacity*	+ 1.96 * *2040_Incremental_Capacity*	= 1.96 * (*2040_Base_Capacity* + *2040_Incremental_Capacity*)

Run Year	Maximum Possible New Nuclear Capacity Deployment Allowed							
	Deployment Starts 2020		Deployment Starts 2030		Deployment Starts 2040		Deployment Starts 2050	
	Incremental	Cumulative	Incremental	Cumulative	Incremental	Cumulative	Incremental	Cumulative
2020	7,500	7,500	0	0	0	0	0	0
2030	29,400	36,900	14,700	14,700	0	0	0	0
2040	86,436	123,336	57,624	72,324	28,812	28,812	0	0
2050	225,886	349,222	169,415	241,739	112,943	141,755	56,472	56,472

Notes:
No nuclear deployment is allowed before 2020
1. Additional new nuclear capacity deployment is only possible if nuclear capacity has been built in the previous run year.



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8. Modeling Results

8.1 Introduction

This chapter presents an estimate of the net benefits of geologic storage (GS) on the Outer Continental Shelf (OCS) to the U.S. economy and discusses the uncertainties in that estimate. The net benefits to the U.S. economy are estimated here using the classical economic definition that net benefits (costs) are the sum of all positive and negative changes in consumer and producers surpluses. These net changes are estimated by comparing a No-OCS Case and OCS Case. The No-OCS Case assumes that no GS of carbon dioxide is allowed on the OCS while the OCS Case assumes GS on the OCS is allowed.

In both cases it is assumed that some form of a national carbon policy is begun in 2015 with an effective price on carbon set to $54 per short ton in 2030 and $152 per short ton in 2050 (real 2010 dollars). As discussed in the prior chapter, the other assumptions for these runs are taken largely from the Energy Information Administration 2011 Annual Energy Outlook (AEO) and the EPA's v4.10 Base Case. The assumptions for carbon prices and electricity growth rates are from EIA's Economywide GHG Policy Case.

The CO_2 allowance prices translate into an increase in retail electricity rates of about $16.25 to $99.00 per megawatt-hour. The 2015 price equates to approximately 1.6 cents per kilowatt-hour. Current retail rates are approximately 10 to 11 cents per kilowatt-hour.

The economic impacts of a policy to allow GS on the OCS are estimated by comparing the results of the two cases. On the whole, the addition of geologic storage (GS) on the OCS has an undiscounted cumulative net benefit to the US economy of $16.9 billion between 2015 and 2054. Less than 2 percent of this benefit occurs before 2030. The size and timing of this benefit depends on many uncertain forecast assumptions such as the timing and severity of future GHG regulations, the degree to which CCS is subsidized, the growth in electricity demand, the price of natural gas, the cost and practicality of building new nuclear power plants, and the cost and practicality of onshore geologic storage of carbon dioxide. Cost-benefit factors that might not be reflected in future market prices (i.e., externalities) also could influence actual net benefits to society, but such externalities are expected to be small.

8.2 Demand for Electricity and Power Plant Construction

The growth in net electricity demand in both the OCS and the No-OCS cases is the same, and is shown below in **Table 21**. There is an effective slowdown in net power demand in the short term due to the lingering effects of economic recession, followed by a slow growth in demand consistent with the 2011 AEO less the conservation effects expected by EIA if a national carbon policy were adopted.

Table 21 Annual Growth Rate of Net Electricity Demand for Base and OCS Cases

	2015-2020	2020-2030	2030-2040	2040-2050
Net Demand **(Growth Rate per annum)**	0.3%	0.4%	0.5%	0.5%

A summary of new economic builds and retirements will be presented subsequently for the two cases.[124] In terms of new economic builds, no coal power plants are built without CCS in the model because it is assumed in both cases that restrictions are put on carbon emissions, producing a cost of carbon emissions of $25/short ton in 2015 rising to $54/ short ton on 2030 and $152/short ton in 2050 (real 2010 dollars).[125]

Most of the new capacity is nuclear power, followed by natural gas-fired combined cycle plants and renewables. About 15 GW of new coal power plants with CCS are built on an annual basis from 2040 onward. The availability of GS on the OCS does not significantly increase the installation of new coal power plants after 2040, as only 241 MW of additional new coal power plants with CCS (15,406 MW *versus* 15,165 MW) are built through 2050 in the Case with OCS and 458 MW less of new nuclear plants are built (323,748 MW *versus* 324,206 MW). This is because the additional EOR from the OCS-based storage allows for the new coal builds and reduced nuclear builds. Due to the slightly increased number of new coal power plants that are built, an additional 14 trillion Btus of coal is consumed per year (after 2040) for power generation in the OCS Case, compared to the No-OCS Case model run.

In the OCS Case, there are about 233 GW of retirements of coal plants by 2050 plus about 129 GW of retirements among old oil/gas steam, combustion turbines and gas-fired combined cycle units. The total retirement in the OCS Case is slightly higher than in the No-OCS Case, as more of the old power plants retire when new coal plants with CCS are built.

[124] "Economic builds" are unplanned power plants that are built by the model based on assumed economic conditions and policies. This does not include planned power plants (including many that are now under construction) whose construction is assumed to be fixed and, therefore, not affected by assumptions that can vary among cases.
[125] All cost data going into IPM are converted to 2007 dollars to be consistent with IPM internal accounting conventions. Results can be reported in any year dollars requested by the user.

There is very little change in national wholesale power prices between the No-OCS Case and the OCS Case. The largest impact is in the 2040 run period in which the national average wholesale prices are reduced by $0.05 per MWH in the OCS Case as compared to the No-OCS Case. Averaged over the entire forecast period of 2015 to 2054, national average wholesale prices are nearly the same between the two cases.

8.3 Geologic Storage Cost Curves and Model Results for Volumes Stored

The supply curve for GS is shown in **Table 22** in terms of the volume of carbon dioxide that can be stored each year versus the cost of the storage. The upper portion of the table shows the gigatonnes of storage capacity and the lower portion of the table shows the assumed annual volumes, based upon dividing the capacity by 50 years of injection.

Note that only cost steps that are at $10 per ton and below are shown in the table, since the higher cost steps are not relevant for the forecast period up to 2050. The cost curves for each onshore and offshore region and each type of storage (enhanced oil recovery, abandoned oil and gas fields, saline reservoirs) were computed in ICF's Geologic Storage Cost Analyst Tool or GeoCAT model. As discussed in the prior chapter, factor costs for the OCS items such as wells, offshore production/injection platforms and pipelines were supplied by BOEM to be consistent with its MAG-PLAN model.

The costs in the table represent full capital, operating and abandonment costs for the GS fields (including all monitoring costs during operations and after closure), but do not include the cost of the carbon dioxide pipelines that would transport the carbon dioxide from power plant and industrial sources to the storage sites. Those carbon dioxide pipeline costs are based on factor costs of $75,000 to $91,000 per inch-mile[126] for onshore or offshore pipeline corridors and storage sites and vary based on the distance and volumes transported. (See Table 10 in Chapter 5.) Generally speaking, pipeline transport costs, where multiple sources can be aggregated into large diameter pipelines, are about $4.61 per ton of carbon dioxide per 150 miles of distance.

As indicated in the GS supply curve below, the addition of GS on the OCS adds about 23 megatonnes per year in the negative cost steps of the supply curve, which represent opportunities for enhanced oil recovery wherein oil producers would be willing to pay for compressed carbon dioxide delivered to their oil fields.

[126] A pipeline inch-mile is the inch diameter times the miles of pipeline. A ten inch pipe over 50 miles equates to 500 inch-miles.

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Table 22 GS Supply Curve With and Without GS on OCS

	Gigatonnes of capacity		
Cost Step Range ($/metric ton)	Quantity without OCS	Quantity on OCS	Total Quantity with OCS
<$(30.00)	12.84	1.13	13.97
$(29.99) - $(20.00)	1.28	0.00	1.28
$(19.99) - $(15.00)	0.38	0.00	0.38
$(14.99) - $(10.00)	0.43	0.00	0.43
$(9.99) - $(5.00)	0.03	0.00	0.03
$(4.99) - $0.00	0.44	0.00	0.44
$0.01 - $5.00	2,339.11	0.00	2,339.11
$5.01 - $10.00	2,829.54	249.07	3,078.62
Total Negative Cost	15.38	1.13	16.51
Lower-48 Total below $10	5,184	250	5,434
Lower-48 Total above $10	2,260	3,393	5,653
Lower-48 Total	7,444	3,643	11,087

	Megatonnes per year (capacity divided by 50 years)		
Cost Step Range ($/metric ton)	Quantity without OCS	Quantity on OCS	Total Quantity with OCS
<$(30.00)	256.8	22.57	279.4
$(29.99) - $(20.00)	25.6	0.00	25.6
$(19.99) - $(15.00)	7.5	0.00	7.5
$(14.99) - $(10.00)	8.5	0.00	8.5
$(9.99) - $(5.00)	0.5	0.00	0.5
$(4.99) - $0.00	8.7	0.00	8.7
$0.01 - $5.00	46,782	0.00	46,782
$5.01 - $10.00	56,591	4,981	61,572
Total Negative Cost	307.60	22.57	330.20
Lower-48 Total below $10	103,681	5,004	108,685

Note: This table includes costs for geologic storage only and excludes the costs of transportation to the storage site and the cost of capture of the CO_2. The table represents full life-cycle capital, operating and abandonment costs for the GS fields including all operational and post-closure monitoring costs. Negative costs occur when CO_2 is sold for enhanced oil recovery (EOR). All of the negative cost components represent EOR. This totals about 330 megatonnes per year. The EOR storage is available at this cost regardless of policy. This is the price the operator has to receive to make the project economic and is negative for EOR because of the oil value.

Beyond the GS storage associated with EOR capacity, the next two cost steps are for $0.00 to $5.00 per ton and $5.01 to $10.00 per ton. The first non-negative possibility of GS on the OCS is at the cost step of $5.01-$10/ton, indicating that there are no non-EOR opportunities below $5.00 per ton. This is important because the cumulative quantity of onshore plus offshore GS capacity with negative cost or positive costs up to $5.00 per ton (excluding pipeline costs) is 47,112 megatonnes per year. This compares to annual US emissions of carbon dioxide from stationary sources of a roughly 3,800 megatonnes per year. Therefore, based on the GS capacity and cost data used in the cases, there would be little need for GS storage capacity costing more than $5.00 per ton, except possibly in areas where no cheaper storage sites were available and where transport costs to such cheaper sites was too expensive. Because the $5.01 to $10.00 cost step is itself very large, 61,572 megatonnes per year, there would be no need for GS capacity costing over $10.00 per ton.

Table 23 shows the annual amounts of carbon dioxide captured and stored and the forecast market costs for GS storage and transport services paid by electricity generators. The capture and storage of carbon dioxide starts in IPM® model run period 2015 (representing the years between 2014 and 2016). In those first years, GS storage takes place only at oil fields for EOR and so net storage and transport cost are negative as the additional revenue from the enhanced oil recovered offsets the costs of bringing the carbon dioxide to the site and storing it. (Of course, electricity generators are paying substantial amounts of money to capture and compress their carbon dioxide and so their total cost for carbon and capture and storage are positive.)

Storage predominately in EOR sites continues until run period 2040 (years 2035 to 2045), when storage in saline aquifers becomes the marginal, price setting type of GS site — thereby producing a net positive GS and transport cost in the model. Overall, the total cost of GS to power generators when the OCS is included is lower than without GS on the OCS, due to the availability of additional, negative cost, EOR storage sites. These savings are $0.1 million per year in the 2020 period, $25.4 million per year in the 2030 period and $116.7 million per year in the 2040 period. In the 2050 period the savings are reversed and the OCS Case has GS plus carbon dioxide transport costs that are $39.1 million higher than the No-OCS Case. This occurs because the market prices in both cases are being set by marginal non-EOR projects (after the EOR projects have all gone into service) and the overall volume of GS (including the OCS) is higher in the OCS Case.

Table 23 Summary of Forecast of Geologic Storage Volumes and Storage and Transport Costs Through 2050

		OCS Case with GS on the OCS		No-OCS Case without GS on the OCS		Delta (OCS Case - No-OCS Case)	
Run Period	**Years Mapped to this Period**	**CO_2 Captured (MM Tons per year)**	**Total GS+Trans. Cost (MM$)**	**CO_2 Captured (MM Tons per Year)**	**Total GS+Trans. Cost (MM$)**	**CO_2 Captured (MM Tons per year)**	**Total GS+Trans. Cost (MM$)**
2015	2014-2016	14.8	-277.6	14.8	-277.6	0.0	0.0
2020	2017-2024	56.5	-1,165.7	56.5	-1,165.7	0.0	-0.1
2030	2025-2034	236.1	-4,094.9	235.1	-4,069.5	1.0	-25.4
2040	2035-2045	663.0	4,067.0	661.9	4,183.7	1.1	-116.7
2050	2046-2054	664.6	3,787.0	663.3	3,747.9	1.3	39.1

As summarized in **Table 24**, GS on the OCS starts in run period 2030 representing 2025 to 2034. The only projected geologic storage on the OCS is of the EOR type in the portion of Gulf of Mexico adjacent to Louisiana. The stored carbon dioxide is captured from plants in IPM's Florida (FRCC) and Southern (SOU) regions. About 50% of carbon dioxide captured in Florida between 2025 and 2034 (4.9 out of 10.7 MM metric tons per year) is being stored on the OCS, but in the later years, nearly 85% of the captured carbon dioxide from Florida is being stored on the OCS (16.8 out of 19.7 MM metric tonnes per year). About 17-20% of the captured carbon dioxide from the Southern region is stored on the OCS, with rest of it being stored in onshore or state water storage sites.

Table 25 summarizes the differences between the two cases (with and without GS on the OCS) in terms of volumes of CO_2 stored onshore and offshore in 2050. In the OCS GS case, about 1.3 MM metric tons per year more are stored nationally. This results from the net change of 21.3 MM metric tons per year less storage onshore and 22.6 MM metric tons stored offshore.

Table 24 Location of Projected OCS Storage for CO_2 Produced in Florida and Southern Regions in OCS Case

Run Period	Years Mapped to this Period	Region Pro-ducing Carbon Dioxide	Total Shipped from this Producing Region (MM Tons per year)	Total Onshore (Alabama, Florida, Louisiana, Mississippi)	ATLANTIC OFFSHORE (MM Tons per year)	LA OFF-SHORE (MM Tons per year)	PACIFIC OFF-SHORE (MM Tons per year)	TX OFF-SHORE (MM Tons per year)
2030	2025-2034	Florida	10.7	5.8	0.0	4.9	0.0	0.0
2040	2035-2045	Florida	21.2	6.1	0.0	15.1	0.0	0.0
2040	2035-2045	Southern	37.4	29.9	0.0	7.5	0.0	0.0
2050	2046-2054	Florida	19.7	2.9	0.0	16.8	0.0	0.0
2050	2046-2054	Southern	37.2	31.5	0.0	5.8	0.0	0.0
2040		Totals	58.6	36.0	0.0	22.6	0.0	0.0
2050		Totals	56.9	34.4	0.0	22.6	0.0	0.0

Table 25 2050 Total U.S. CO_2 Stored by Model Case

Case	**CO_2 Stored Onshore (MM Tons per year)**	**CO_2 Stored Offshore (MM Tons per year)**	**Total CO_2 Stored (MM Tons per year)**
No GS on the OCS	663.3	0	663.3
GS on the OCS	642.0	22.6	664.6
Difference	-21.3	22.6	1.3

8.4 Economic Assessment

On an undiscounted basis, the addition of GS on the OCS has a cumulative net benefit to the US economy of $0.26 billion dollars between 2015 and 2030 and $16.9 billion between 2015 and 2050.

These net benefits represent the net changes in producer and consumer surplus throughout the economy. The benefit is split out among various parts of the US economy including providers of GS services, EOR operators, electricity consumers, natural gas consumers and natural gas producers (**Table 26**).

The largest benefit ($15.46 billion) goes to GS service providers/EOR operators[127] who will benefit from having the opportunity to develop carbon sequestration EOR projects on the OCS. The next largest benefit ($1.98 billion) is for natural gas producers as natural gas prices increase slightly. An additional benefit ($1.44 billion) goes to electricity consumers and generators, as the cost of GS storage and transport is reduced. Natural gas consumers experience a negative benefit of $1.98 billion, equivalent to the gas producer surplus.

Coal producers and consumers experience no significant benefits.

Table 27 presents the detailed model results. The columns on the right side of the table show the differences between the cases with and without GS on the OCS. A policy of allowing GS on the OCS slightly increases the overall demand for natural gas for power generation, between 2 to 16 bcf per year, with variations on an annual/run year basis. The availability of more economic CCS options on the OCS reduces the amount of nuclear new builds. The reduction of new nuclear builds not only increases coal with CCS builds, but also provides an opportunity for new combined cycle plants, as the cost of the natural gas-based combined cycle plants is much lower than the costs of coal plants with CCS.

This slight demand increase for natural gas slightly increases the price of gas by less than 0.3 cents per MMBtu. This change increases gas producer surplus, but decreases gas consumer surplus by nearly the same amount of roughly $70-120 million annually. The gain to gas producers that is not lost by consumers (and thus the change to the objective function) is just $2,000 to $80,000 per year. On a present value basis, the cumulative objective function is reduced by just $0.15 million due to the loss of gas consumer surplus in excess of gas producer surplus gain.

There is also a small increase in coal consumption in the OCS Case as compared to the No-OCS Case. This might be expected to add to coal producer surpluses and reduce

[127] The companies who provide "geologic storage services" may be the same companies who are the EOR operators or they might be separate entities.

surplus of coal consumers. However, the IPM® model shows very small change in coal prices, as shown in the **Table 27**.

Table 26 Breakout of Economic Net Benefit by Sector (Negative Values Indicate Loss of Economic Surpluses)

Sector	Discounted Billion Dollars (2015 to 2054)	Undiscounted Billion Dollars (2015-2030)	Undiscounted Billion Dollars (2015-2054)
Electricity Consumers / Electricity Generators	+$0.41	+$0.23	+$1.44
Providers of GS Services / EOR Operators	+$2.37	+$0.03	+$15.46
Natural Gas Producers	+$0.40	+$0.40*	+$1.98
Natural Gas Consumers	-$0.40	-$0.40*	-$1.98
Coal Producers	*Negligible effects*	*Negligible effects*	*Negligible effects*
Coal Consumers	*Negligible effects*	*Negligible effects*	*Negligible effects*
Total	**$2.78**	**$0.26**	**$16.90**

** Natural gas price effects occur earlier than other effects because IPM's perfect foresight assumption that causes a change in the mix of generating units and thus reduces the use of natural gas in years before there is use of geologic storage capacity in the OCS.*

Table 27 Summary Tables for Model Runs

(Continued next page)

Power Demand	No-OCS Case (Without GS on OCS)						OCS Case (With GS on OCS)						Delta (OCS *minus* No-OCS)					
	2012	2015	2020	2030	2040	2050	2012	2015	2020	2030	2040	2050	2012	2015	2020	2030	2040	2050
Net Demand [TWh]	3,979	3,858	3,912	4,090	4,311	4,538	3,979	3,858	3,912	4,090	4,311	4,538	0	0	0	0	0	0

Early Retirements (GW)	No-OCS Case (Without GS on OCS)						OCS Case (With GS on OCS)						Delta (OCS *minus* No-OCS)					
	2012	2015	2020	2030	2040	2050	2012	2015	2020	2030	2040	2050	2012	2015	2020	2030	2040	2050
Coal Steam	0	66	97	168	202	233	0	66	97	168	202	233	0.000	-0.005	0.003	-0.179	0.009	0.014
Other Fossil Fuel	0	23	55	65	65	129	0	23	55	65	65	129	0.000	-0.033	-0.033	0.300	0.300	0.046

New Builds (GW)	No-OCS Case (Without GS on OCS)						OCS Case (With GS on OCS)						Delta (OCS *minus* No-OCS)					
	2012	2015	2020	2030	2040	2050	2012	2015	2020	2030	2040	2050	2012	2015	2020	2030	2040	2050
Coal Steam with CCS	0	2	2	6	15	15	0	2	2	7	15	15	0.000	0.000	0.000	0.081	0.241	0.241
Coal Steam without CCS	0	0	0	0	0	0	0	0	0	0	0	0	0.000	0.000	0.000	0.000	0.000	0.000
Nuclear	0	0	6	32	111	324	0	0	6	32	111	324	0.000	0.000	-0.032	-0.094	-0.218	-0.458
Combined Cycles	1	1	1	104	157	157	1	1	1	104	157	157	0.000	0.000	0.000	0.143	0.316	0.316
Combustion Turbines	2	2	2	2	2	2	2	2	2	2	2	2	0.000	0.000	0.000	0.000	0.000	0.000
Renewables	23	28	31	43	63	63	23	28	31	43	63	63	0.000	0.004	0.003	-0.007	-0.141	-0.141
Total	26	34	41	187	349	562	26	34	41	187	349	562	0.000	0.004	-0.029	0.123	0.198	-0.042

Capacity Mix (GW)	No-OCS Case (Without GS on OCS)						OCS Case (With GS on OCS)						Delta (OCS *minus* No-OCS)					
	2012	2015	2020	2030	2040	2050	2012	2015	2020	2030	2040	2050	2012	2015	2020	2030	2040	2050
Coal Steam with CCS	0.0	2.0	5.7	24.4	75.0	76.7	0.0	2.0	5.7	24.5	75.2	76.9	0.000	0.000	0.000	0.078	0.235	0.235
Coal Steam without CCS	319.0	250.6	214.2	123.4	33.6	1.0	319.0	250.6	214.2	123.6	33.6	1.0	0.000	0.006	-0.003	0.186	0.007	0.000
Oil/Gas Steam	109.5	90.1	58.1	48.6	48.6	13.2	109.5	90.1	58.1	48.2	48.2	13.2	0.000	0.001	-0.001	-0.333	-0.333	0.050
Nuclear	102.1	104.5	111.5	134.9	170.8	331.4	102.1	104.5	111.4	134.8	170.6	330.9	0.000	0.000	-0.032	-0.094	-0.218	-0.458
Combined Cycles	206.5	202.6	202.6	305.5	358.8	329.5	206.5	202.7	202.7	305.7	359.2	329.7	0.000	0.033	0.033	0.176	0.349	0.218
Combustion Turbines	143.3	143.0	143.0	143.0	143.0	143.0	143.3	143.0	143.0	143.0	143.0	143.0	0.000	0.000	0.000	0.000	0.000	0.000
Hydro	98.8	98.8	98.8	98.8	98.8	98.8	98.8	98.8	98.8	98.8	98.8	98.8	0.000	0.000	0.000	0.000	0.000	0.000
Renewables	68.4	74.1	76.3	88.4	109.1	109.3	68.4	74.1	76.3	88.4	108.9	109.1	0.000	0.004	0.003	-0.007	-0.141	-0.141
Other	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	0.000	0.000	0.000	0.000	0.000	0.000
Total	1,051.5	969.9	914.2	971.1	1,041.7	1,106.9	1,051.5	969.9	914.2	971.1	1,041.6	1,106.8	0.000	0.044	0.000	0.006	-0.101	-0.096

(Table 27 continued)

Generation Mix (GWh)	No-OCS Case (Without GS on OCS)						OCS Case (With GS on OCS)						Delta (OCS *minus* No-OCS)					
	2012	2015	2020	2030	2040	2050	2012	2015	2020	2030	2040	2050	2012	2015	2020	2030	2040	2050
Coal Steam	1,892	1,579	1,367	865	609	558	1,892	1,579	1,367	864	610	559	-0.05	0.07	0.03	-0.50	1.62	1.45
Oil/Gas Steam	20	11	22	8	1	2	20	11	22	8	1	2	0.00	0.03	-0.01	-0.30	0.00	0.00
Nuclear	812	831	886	1,070	1,351	2,613	812	831	886	1,070	1,349	2,610	0.00	0.00	-0.25	-0.75	-1.72	-3.56
Combined Cycles	690	750	911	1,381	1,520	552	690	750	911	1,382	1,520	555	0.06	-0.09	0.21	1.55	0.68	2.48
Combustion Turbines	14	21	28	18	15	3	14	21	28	18	15	3	0.00	0.00	0.02	0.05	-0.03	0.03
Hydro	279	281	282	279	275	288	279	281	282	280	275	288	0.00	-0.01	0.00	0.03	0.02	-0.01
Renewables	243	328	335	363	427	426	243	328	335	363	426	425	-0.02	0.01	-0.01	-0.04	-0.53	-0.44
Other	23	23	23	21	20	20	23	23	23	21	20	20	0.00	0.00	0.00	0.00	0.00	0.00
Total	3,974	3,824	3,854	4,005	4,218	4,462	3,974	3,824	3,854	4,005	4,218	4,462	-0.01	0.01	0.00	0.06	0.04	-0.05

Fuel Consumption (1000 TBtu)	No-OCS Case (Without GS on OCS)						OCS Case (With GS on OCS)						Delta (OCS *minus* No-OCS)					
	2012	2015	2020	2030	2040	2050	2012	2015	2020	2030	2040	2050	2012	2015	2020	2030	2040	2050
Coal	18.96	15.62	13.52	8.77	7.45	6.99	18.96	15.62	13.52	8.77	7.46	7.00	-0.001	0.000	0.001	-0.005	0.014	0.014
Nuclear	8.51	8.71	9.29	11.22	14.13	27.31	8.51	8.71	9.29	11.21	14.11	27.27	0.000	0.000	-0.003	-0.008	-0.018	-0.037
Natural Gas	5.36	5.77	7.21	9.63	10.29	3.66	5.36	5.77	7.21	9.64	10.29	3.68	0.000	0.000	0.002	0.008	0.003	0.016
Biomass	0.32	1.04	1.16	1.07	1.10	1.13	0.32	1.04	1.16	1.06	1.10	1.13	0.000	0.000	0.000	-0.001	0.000	0.000

Emissions (MMTonnes)	No-OCS Case (Without GS on OCS)						OCS Case (With GS on OCS)						Delta (OCS *minus* No-OCS)					
	2012	2015	2020	2030	2040	2050	2012	2015	2020	2030	2040	2050	2012	2015	2020	2030	2040	2050
CO_2 Emissions	2,154	1,839	1,677	1,183	683	277	2,154	1,839	1,677	1,182	684	278	-0.02	0.03	0.15	-0.99	0.49	1.01
CO_2 Sequestered	0	13	51	213	600	602	0	13	51	214	601	603	0.00	0.00	0.00	0.88	0.97	1.24

Prices	No-OCS Case (Without GS on OCS)						OCS Case (With GS on OCS)						Delta (OCS *minus* No-OCS)					
	2012	2015	2020	2030	2040	2050	2012	2015	2020	2030	2040	2050	2012	2015	2020	2030	2040	2050
National Minemouth Coal Prices (2007 $/MMBtu)	1.23	1.22	1.27	1.33	1.31	1.33	1.23	1.22	1.27	1.33	1.31	1.33	0.000	0.000	0.000	0.001	-0.001	-0.001
Coal Prices (2007$/MMBtu)	1.96	1.89	1.83	1.77	1.68	1.70	1.96	1.89	1.83	1.77	1.68	1.70	0.000	0.000	0.000	0.001	-0.001	-0.002
Gas Prices (2007$/MMBtu)	3.90	5.93	5.41	6.57	7.81	3.95	3.90	5.94	5.41	6.57	7.81	3.95	0.000	0.001	-0.002	0.003	-0.004	0.000
Wholesale Power Prices (2007$/MWh)	34.95	63.55	67.46	82.37	104.95	79.98	34.94	63.55	67.45	82.40	104.90	80.05	-0.004	0.006	-0.010	0.029	-0.046	0.072

Total Electricity Production Cost (Billion	No-OCS Case (Without GS on OCS)						OCS Case (With GS on OCS)						Delta (OCS *minus* No-OCS)					
	2012	2015	2020	2030	2040	2050	2012	2015	2020	2030	2040	2050	2012	2015	2020	2030	2040	2050
Variable O&M	10.43	10.59	10.72	11.85	14.08	13.46	10.43	10.59	10.72	11.85	14.08	13.47	0.000	0.000	0.000	0.006	0.005	0.011
Fixed O&M	39.43	42.04	42.23	45.71	46.25	51.16	39.43	42.04	42.23	45.71	46.22	51.12	0.000	0.002	-0.001	0.003	-0.027	-0.039
Fuel	65.29	73.60	74.47	91.08	107.12	51.69	65.29	73.61	74.46	91.16	107.10	51.73	-0.002	0.002	-0.009	0.075	-0.015	0.040
Capital	6.81	9.67	14.33	45.19	98.17	194.10	6.81	9.67	14.31	45.19	98.15	193.96	0.000	0.001	-0.015	-0.001	-0.026	-0.136
CO_2 Transport and Storage	0.00	-0.28	-1.17	-4.07	4.18	3.75	0.00	-0.28	-1.17	-4.09	4.07	3.79	0.000	0.000	0.000	-0.025	-0.117	0.039
CO_2 Bonus Allowance	0.00	48.25	56.19	63.81	54.86	32.92	0.00	48.25	56.20	63.74	54.89	33.06	0.000	0.001	0.005	-0.071	0.032	0.142
Total System Cost	121.97	183.88	196.78	253.57	324.65	347.06	121.96	183.88	196.76	253.56	324.51	347.12	-0.002	0.006	-0.019	-0.014	-0.148	0.058

8.5 Uncertainty in Estimates of Net Benefits

The size and timing of this benefit depends on many uncertain forecast assumptions such as the timing and severity of future GHG regulations, degree to which CCS is subsidized, growth in electricity demand, the price of natural gas, the cost and practicality of building new nuclear power plants, and the cost and practicality of onshore geologic storage of carbon dioxide. The following is a summary of the potential effects of these factors.

- If GHG regulations are delayed, the need to CCS will also be delayed and the present value of benefits from GS on the OCS will be reduced. The opposite is true if GHG regulations are put in place sooner than assumed here.

- The severity of GHG regulations are important in that the higher the actual or implied price put on carbon emissions, the faster CCS will be adopted and the greater the present value of the net benefit of GS on the OCS (as measured by market prices). Conversely, low carbon price will delay the adoption of CCS and the benefits of GS on the OCS.

- The analysis presented here assumes that a national GHG policy will subsidize CCS in the early years when the actual or imputed allowance costs are insufficient to justify CCS. If such subsidization does not occur, CCS will be delayed and the present value of benefits from GS on the OCS will be reduced.

- To the extent that natural gas prices are lower than those in the BOEM Base Case, it will delay the adoption of CCS and make the net benefits of GS on the OCS lower. If natural gas prices were higher, the CCS adoption would be faster and the present value of benefits of GS on the OCS greater.

- If the growth in electricity demand were faster than that of the AEO Economywide GHG Policy Case then the market for CCS would be larger in the next few decades and the present value of benefits of GS on the OCS would be larger. Slower growth in the demand for electricity would delay CCS and reduce the calculated benefits.

- Since nuclear power plants are projected to be a major GHG mitigation measure, any assumption that increases the cost of nuclear power plants or makes them more difficult to permit and build would accelerate the adoption of CCS and make the present value of benefits from GS on the OCS greater. On the other hand reductions in nuclear costs (such as through technological breakthroughs) would delay CCS and reduce the value of GS on the OCS.

- The most direct competitor with GS on the OCS is onshore GS. Anything that makes onshore GS more expensive or less practical will increase the value of GS on OCS. Onshore geologic storage could be made less competitive due to

NIMBY concerns and other factors that delay the necessary legal and regulatory structures or approvals or add capital and operating costs.

8.6 External Costs and Benefits of CO_2 Sequestration Offshore

Costs or benefits which are not reflected in market prices are often referred to as externalities. Such factors are "external" to the market but can be "internalized" by the imposition of taxes, fees or regulations. It is possible that a policy to allow GS on the OCS might produce externalities in the form of:

- Net impacts on GHG or criteria pollutants from carbon capture and storage versus alternative GHG mitigation technologies that are displaced. This might occur to the extent that the social cost of the pollution is not reflected in the pollutant's market price or regulated control stringency.

- Fewer leaks of CO_2 from onshore sites or more leaks from offshore GS sites. This might occur if the social costs of the leaks (environmental, human health and property damages) are not fully captured by monitoring regulations, corrective action requirements and rules for surrendering allowances.

- Increased energy security and other external benefits from oil production from EOR on the OCS made possible by increased availability of CO_2. Such an externality implies that the price of oil does not fully reflect its full cost to society.

- Foreclosure of alternative OCS land and seaway uses to the extent that any such foreclosure is necessary and is not reflected in the prices paid for land use rights for GS and alternative uses.

- Effects of greater use of Federal and State CCS financial incentives for CCS to the extent they create economic distortions and dead weight economic losses – and are not just economic transfers.

- Benefit from an acceleration of the adoption of GS technologies brought on by risk reduction and more favorable public perceptions of GS OCS *versus* onshore GS.

The assumption made in this report is that significant potential externalities related to carbon capture and storage, particularly those stemming from environmental and human safety impacts, will be internalized through GHG and geologic storage regulations. In other words:

- The modeled price trajectory of carbon emissions (for example, representing future dollar per tonne of CO_2 - equivalent allowance prices) is assumed to fully reflect the social costs of climate change.

- The capital and operating costs estimated for geologic storage include the costs of complying with environmental and safety regulations. Those regulations properly balance the costs against the potential societal benefits from protection of the environment and human health and safety.

- The regulations of air, water, and solid waste pollutants from all types of electric power plants are properly regulated so that potential externalities have been internalized.

- The leasing of land on the OCS for GS will be done so as to accommodate and balance competing uses.

To the extent that regulations are not adequate in balancing societal costs and benefits or if market prices do not fully reflect societal costs, it is possible that some externalities will arise from the environmental, safety and other impacts associated with GS on the OCS.