Federal Control of Geological Carbon Sequestration

Topical Report

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Abstract

The United States has economically recoverable coal reserves of about 261 billion tons, which is in excess of a 250-year supply based on 2009 consumption rates. However, in the near future the use of coal may be legally restricted because of concerns over the effects of its combustion on atmospheric carbon dioxide concentrations. In response, the U.S. Department of Energy is making significant efforts to help develop and implement a commercial scale program of geologic carbon sequestration that involves capturing and storing carbon dioxide emitted from coal-burning electric power plants in deep underground formations. This article explores the technical and legal problems that must be resolved in order to have a viable carbon sequestration program. It covers the responsibilities of the United States Environmental Protection Agency and the Departments of Energy, Transportation and Interior. It discusses the use of the Safe Drinking Water Act, the Clean Air Act, the National Environmental Policy Act, the Endangered Species Act, and other applicable federal laws. Finally, it discusses the provisions related to carbon sequestration that have been included in the major bills dealing with climate change that Congress has been considering in 2009 and 2010. The article concludes that the many legal issues that exist can be resolved, but whether carbon sequestration becomes a commercial reality will depend on reducing its costs or by imposing legal requirements on fossil-fired power plants that result in the costs of carbon emissions increasing to the point that carbon sequestration becomes a feasible option.

Executive Summary

This report analyzes the federal response to the technical and legal problems of implementing carbon capture and sequestration. Although new technologies can significantly decrease the greenhouse gas emissions of coal-fired power generation and could facilitate geologic sequestration of carbon dioxide, these technologies are expensive and have not yet been widely implemented throughout the U.S. In addition, the capture, transport, and storage of carbon dioxide present both technological and legal challenges to assure public safety, provide stability for industry investments, and regulate site selection, project management, and long-term liability.

The federal government has invested increasing amounts of money in carbon capture and sequestration development, several federal agencies have also responded with new rules and regulations that will affect how carbon may be captured, transported, and sequestered. The United States Environmental Protection Agency and the Departments of Energy, Transportation and Interior all have regulations that affect carbon capture and storage.

EPA regulates underground carbon injection through the Safe Drinking Water Act. Recently finalized regulations require permits for underground carbon injection, project monitoring and reporting, and proof of fiscal responsibility. Parts of the Clean Air Act will also impact carbon capture and storage, including sequestration as a trigger for Prevention of Significant Deterioration or New Source Review requirements, the possibility that carbon capture and sequestration or other clean coal technologies might be required as the Best Available Technology, and the potential for sequestration facilities to be subject to other regulations applicable to stationary sources. The National Environmental Policy Act, the Endangered Species Act, and other applicable federal pollution, planning, and leasing laws may also apply to carbon capture and sequestration.

The Department of Energy's greatest impact has been from increased funding of carbon capture and sequestration development and the creation of regional partnerships to decrease the cost and energy penalty of carbon capture and sequestration as well as to improve the permanence and safety of carbon storage.

Finally, the report examines recent federal legislative proposals that would impact carbon capture and sequestration. Cap-and-trade legislation introduced in 2009 would place a price on carbon emissions, which would make carbon capture and sequestration a more economically feasible option. However, proposed bills in the House and the Senate are unlikely to be enacted. The November 2010 national elections will have a major effect on climate change legislation. In the House the Republican Party will assume the leadership role. In the Senate, committees will operate with fewer Democrats. Republicans have elected not to continue the House Select Committee on Energy Independence and Global Warming. Legislative proposals will become more narrowly focused on issues that can obtain Republican

support. How this change in the composition of the Congress will effect the development of CCS is unknown at this time.

For the foreseeable future costs will be the primary barrier to the implementation of carbon capture and sequestration. The absence of any commercial-scale use at a large power plant is an important constraint on program development because meaningful cost data is difficult to obtain. The projected high cost of carbon capture and sequestration will also be affected by whatever develops concerning a carbon emissions trading program. If sequestration on a commercial scale is to occur, the Department of Energy will need to play a major role in funding and evaluating this technology at a commercial scale, and the federal government will need to provide a legal environment that nurtures a new industry. Carbon dioxide capture and storage could become a necessity if coal is to be used for electric power generation in a carbon-constrained economy, but the high costs of carbon capture and sequestration could make natural gas fired plants as well as nuclear power and renewable power more attractive to utilities than trying to deal with sequestration. While regulatory demands to reduce carbon emissions could make carbon capture more attractive, the continuously more stringent pollution control requirements and the associated costs make coal-fired power plants a questionable investment. Sequestration is a way of dealing with emissions from an electric generation technology that needs to be improved if it is to avoid being phased out. This creates ongoing pressure on sequestration supporters to lower costs and demonstrate the commercial viability of geological carbon sequestration in order to use the nation's lowest cost and most plentiful source of energy—coal.

List of Acronyms

ACELA	American Clean Energy Leadership Act of 2009 (SB 1462)
ACES	American Clean Energy and Security Act of 2009 (HR 2454)
AmPA	American Power Act
AoR	Area of Review
ARRA	American Recovery and Reinvestment Act
BACT	Best Available Control Technology
BiOP	Biological Opinion
BLM	Bureau of Land Management
CAA	Clean Air Act
CCS	Carbon Capture and Sequestration
CCTP	Climate Change Technology Program
CEQ	Council on Environmental Quality
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act of 1980
CO_2	Carbon Dioxide
CO_{2e}	Carbon Dioxide Equivalent
DOE	Department of Energy
DOI	Department of the Interior
DOT	Department of Transportation
EAB	Environmental Appeals Board
EGR	Enhanced Gas Recovery
EGU	Electric Generating Unit
EIS	Environmental Impact Statement
ENR Committee	Senate Committee of Energy and Natural Resources
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
ER	Enhanced Recovery
ESA	Endangered Species Act
FERC	Federal Energy Regulatory Commission
FLPMA	Federal Land Management Act
FONSI	Finding of No Significant Impact
FWS	Fish and Wildlife Service
GHG	Greenhouse Gas
GS	Geologic Storage
Gt	Gigatons
Gw	Gigawatts
HAP	Hazardous Air Pollutant
HFC	Hydrofluorocarbons
IGCC	Integrated Gasification Combined Cycle
IOGCC	Interstate Oil and Gas Compact Commission
IPCC	Intergovernmental Panel on Climate Change
IRS	Internal Revenue Service
KWh	Kilowatt Hour
LAER	Lowest Achievable Emission Rate

LBNL	Lawrence Berkeley National Laboratory
LDV	Light-duty Vehicles
mcf	Thousand Cubic Feet
MIT	Mechanical Integrity Test
MLA	Mineral Leasing Act
MRV	Monitoring, Reporting and Verification
MW	Megawatt
MWh	Megawatt Hour
NAAQS	National Ambient Air Quality Standards
NATCARB	National Carbon Sequestration Database and Geographic Information System
NCER	National Center for Environmental Research
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NGCC	Natural Gas Combined Cycle
NIMBY	Not in my backyard
NMFS	National Marine Fisheries Service
NOAA	National Oceanic and Atmospheric Administration
NO_x	Nitrogen Oxide
NSPS	New Source Performance Standards
NSR	New source review
OPA	Oil Pollution Act
ORD	EPA's Office of Research and Development
PHMSA	Pipeline and Hazardous Materials Safety Administration
PISC	Post-injection Site Care
PSD	Prevention of Significant Deterioration
QASP	Quality Assurance and Surveillance Plan
RCRA	Resource Conservation and Recovery Act
RCSP	Regional Carbon Sequestration Partnership
RFDS	Reasonable Foreseeable Development Scenarios
RMP	Resource Management Plan
SDWA	Safe Drinking Water Act
STAR	Science To Achieve Results
TAPL	Trans-Alaska Pipeline Liability Fund
TDS	Total Dissolved Solids
TMDL	Total Maximum Daily Load
TNW	Tangible net worth
tpy	Tons per Year
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
USGS	U.S. Geological Survey
WESTCARB	West Coast Regional Carbon Sequestration Partnership

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§ 1. Introduction to Coal-Fired Electric Power Generation

Fossil-fueled electric power generation in the United States is the most significant source of carbon dioxide (CO_2) emissions, which are contributing to climate change.[1] This makes the industry a primary target of efforts to reduce emissions of CO_2, which can be accomplished by: 1) improved efficiency in the generation of electricity energy or by using fossil fuel having lower carbon emissions; 2) energy conservation and improved efficiency in the use of electric power; 3) using renewable energy or nuclear power; 4) using ocean or terrestrial capture for biological sequestration; 5) mineralization of CO_2;[2] or 6) carbon capture and storage (CCS) in geological formations. It is this last approach that is the subject of this report.[3] Because CCS operates in close conjunction with the technology used for generating electricity, a brief summary of the developing technologies related to CCS efforts will first be presented

There were 1,445 coal-fired electric power generators in 2008 with a capacity of 337,300 MW.[4] Because power plants utilizing various energy inputs operate with differing capacity factors, the net electrical energy generated in 2008 by energy input was: 48.2% coal, 21.4% natural gas, 20.6% nuclear, 6.2% hydroelectric, 3.1% from renewable energy (1.3% from wind) and 1.1% petroleum.[5]

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[1] CO_2 accounted for 85.0% of the U.S. GHG emissions in 2008; emissions in the U.S. decreased 3.0% from 2007 to 2008 but increased 16.2% from 1990 to 2008. U.S. Energy Information Agency, *U.S. Carbon Dioxide Emissions from Energy and Industry, 1990-2008,* tbl 5, *available at* http://wwweia.doe.gov/oiaf/1605/ggrpt/carbon.html (last visited July 6, 2010). Fossil fuel combustion in 2008 was responsible for 94.1% of U.S. CO_2 emissions and 80.1% of the U.S. GHG emissions. U.S. ENVTL. PROTECTION AGENCY, 2010 U.S. GREENHOUSE GAS INVENTORY REPORT, EXECUTIVE SUMMARY (2010), tbl. ES-2, *available at* http://epa.gov/climatechange/emissions/downloads10/US-GHG-Inventory-2010_ExecutiveSummary.pdf (last visited July 6, 2010). Electric power plants emit 39.91% of U.S. CO_2 emissions, which makes them the most important source of CO_2 emissions, followed by transportation with 30.15%. *Id.* at tbl. ES-2.

[2] CO_2 reacts with divalent cations with alkalinity to precipitate carbonates. The result is a rock like material that can be placed on the ground or used as a building material. Several companies are trying to create a business using this approach. *See e.g.* http://calera.com (last visited Feb. 8, 2010).

[3] The other approaches are discussed in Arnold W. Reitze, Jr., *Federal Control of Carbon Dioxide Emissions: What are the Options?,* 36 BOS. COL. ENVTL. AFF. L. REV. 1 (2009).

[4] Calculated from data at U.S. Department of Energy, Energy Information Administration, Existing Capacity by Energy Source 2008, *available at* http://www.eia.doe.gov/cneaf/electricity/epa/epat1p2.html (last visited July 9, 2010).

[5] Calculated from Energy Information Administration data at http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html (last visited Apr. 6, 2010). The electric generation nameplate capacity in the United States was 1,104,486 MW; electric power production capacity by fuel source was: 30.54% coal, 41.16% natural gas, 9.61% nuclear, 5.76% petroleum, 7.03% conventional hydroelectric, and 2.26% from wind and a nearly insignificant capacity from other renewables. Nameplate capacity for wind energy was 24,980 MW, solar and photovoltaic capacity was 539 MW, and geothermal capacity was 3,281 MW. *Id. See also* U.S. Dept. of Energy, Energy Information Administration, U.S. Carbon Dioxide Emissions from Energy Sources 2008 Flash Estimates, available at http://www.eia.doe.gov/oiaf/1605/flash/flash.html (last visited March 3, 2010).

Approximately one ton of CO_2 is produced for each megawatt-hour (MWh) of electricity generated using coal,[6] but emissions vary significantly, depending on factors such as the fuel and technology used and the age of the plant.[7]

The future role of coal in generating electricity in the United States is an important policy issue that has not yet been resolved. Costs of electricity can be expected to continue to rise because of the federal laws discussed in this report as well as state laws requiring reductions in greenhouse gases (GHGs) and laws imposing renewable energy and energy efficiency requirements. If sequestration of CO_2 emissions is required, the cost of electricity will increase significantly although the costs and effectiveness of such measures is currently uncertain. However, as the cost of electricity increases because of more stringent environmental laws, including those aimed at controlling GHGs, both sequestration and using fuel other than coal become more attractive options.

The coal-fired electric power industry not only faces expensive regulatory requirements related to climate change, but it faces construction cost increases that threaten the economic viability of new coal-burning plants. New coal-fired plants cost $2 billion to $3 billion.[8] They are two to three times more costly than new plants built in the 1970s even without CO_2 control. Moreover, the worldwide growth in electric power generation is creating competition for the resources and skills necessary to build plants, and that is leading to skyrocketing increases in construction costs.[9] These costs may be difficult to recover from the revenues that can be garnered in a competitive or in a regulated electric power market.[10] At the same time that costs of new power plants are increasing there is continuing pressure to close old coal-fired power plants. Half of the currently operating U.S. power plants were built before 1980, and they produced seventy-three percent of the U.S. power plant CO_2 emissions in 2007.[11]

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[6] In 2010 the net electricity generated from coal was 1,764 million MWh. *See* Energy Information Administration, DOE, Table 1.1 Net Generation by Energy Source, *available at* http://www.eia.doe/cneaf/electricity/epm/table1_1. html (last visited July 8, 2010). Coal used to generate electricity in 2008 was responsible for the release of 1962.6 million metric tons of CO_2 equivalent GHGs. *See* 2010 INVENTORY OF U.S. GREENHOUSE GASES, tbl. 3-5, CO_2 Emissions from Fossil Fuel Combustion by Fuel Type and Sector (Tg CO_2 Eq.), *available at* http://epa.gov/climatechange/emissions/downloads10/US-GHG-Inventory-2010_Chapter3-Energy.pdf (last visited July 8, 2010). This is 1.11 metric tons per MWh.

[7] *See* 2010 INVENTORY OF U.S. GREENHOUSE GASES, *supra* note 6.

[8] Dean Scott, *House Bill Carbon Incentives Lauded; Energy Industry Calls for Regulatory Certainty,* 40 Env't Rep. (BNA) 1820 (July 31, 2009).

[9] *ICCR Report: Coal-Fired Power Plants Facing Risks, Uncertainties, Cost Hikes 'Comparable' to Those That Pulled the Plug on Nuclear Power I U.S.* *http://www.iccr.org.news/press.releases2008/pr_coalpanel1022608.htm* (last visited Aug. 31, 2010).

[10] Such concerns, for example, led American Municipal Power, Inc. to terminate its efforts to build a pulverized coal-fired plant in Meigs County, Ohio, after it received its air permits. *Lawmakers Urge Steps To Stem Closures Of Coal Plants Due To Costs,* XX CLEAN AIR REP. (INSIDE EPA) 25:12 (DEC. 10, 2009).

[11] Andrew Childers, *Power Plant Emissions of Carbon Equivalent Said to Be Three Times More Than All Cars,* 40 Env't Rep. (BNA) 2763 (Dec. 4, 2009).

In early 2008 there were twenty-four coal-fired plants under construction involving $23 billion of new capital investment. These facilities would be far less polluting than older existing plants, but they would be expected to contribute massive amounts of CO_2 to the atmosphere for a half-century or more. For this reason, environmental groups and state governments caused electric utilities to cancel or delay the construction of 100 coal-fired power plants between 2001 and mid-2009.[12] The coal industry is fighting to survive by lobbying to have the federal government dramatically increase the funding for clean coal-related programs. If they are successful in obtaining funding and the money expended results in technology advances that reduce or eliminate the threat to the planet, continued dependence on coal-fired electric power plants will likely continue.[13]

§ 1(a). Coal-Fired Power Plant Technology

If sequestration is to become an accepted method of dealing with CO_2 emissions the technology used to generate electricity will likely play a role. For new coal-burning electric power plants conventional technology is pulverized coal boilers because it generates electricity at the lowest cost of any fossil fuel-based technology.[14] Conventional coal-burning plants can increase their overall efficiency by using heat that would otherwise be wasted to supply process steam to industrial or commercial customers. Such facilities are called cogeneration facilities.[15]

A typical subcritical pulverized coal-fired power plant has an efficiency of about 37%.[16] State-of-the-art coal-fired plants, which utilize super critical steam technology, without cogeneration, have an efficiency of about 42% regardless of whether they are pulverized coal, pressurized fluidized bed combustion, or integrated gasification combined cycle (IGCC) facilities.[17] Ultra-supercritical

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[12] Steve Cook, *With Coal-Fired Plant in Utah Canceled, Sierra Club Says 100 Facilities Shelved,* 40 Env't Rep. (BNA)1711 (July 17, 2009). This issue is covered in more detail *infra* § 3(b)(1).
[13] Lynn Garner, *Coal, Electricity Industries Ask White House To Double Funding for Carbon Technologies,* 39 Env't Rep. (BNA) 157 (Jan. 25, 2008).
[14] G.T. Bielawski, J.B. Rogan, D.K. McDonald, *How Low Can We Go? Controlling Emissions in New Coal-Fired Power Plants,* U.S. EPA/DOE/EPRI Combined Power Plant Air Pollutant Control Symposium (Aug. 20-23, 2001).
[15] The Carnot cycle utilizes heat energy in the form of steam to produce mechanical energy to drive a generator to yield marketable and transportable electrical energy. When industrial customers use process steam from a power plant they are utilizing heat energy rather than electrical energy. The second law of thermodynamics limits the efficiency of the Carnot cycle to [1- temperature of the heat sink/temperature of the heat source] x 100%, where the temperature is measured in degrees Kelvin.
[16] Albert J. Bennett, *Progress of the Weston Unit 4 Supercritical Project in Wisconsin* 4 (Babcock & Wilcox Nov. 2006).
[17] Bielawski, *supra* note 14. A plant can achieve this efficiency without a combined cycle or cogeneration through high temperature operation (1085^0 F) using superheated steam at 3775 pounds per square inch gage with a reheat to 1085^0 F. However, the exhaust steam from the high-pressure turbine subsequently can be utilized in a low-pressure turbine or it can be used as process steam, which is usually at temperatures below 400 degrees Fahrenheit in order to increase efficiency. Bennett, *supra* note 16.

pulverized coal power plants that use two reheat cycles are estimated to achieve 48% efficiency.[18]

CO_2 that is created during the combustion of fossil fuel can be reduced by using less fuel per MWh of electricity generated, but improved efficiency usually involves increasing the temperature and pressure of the system, which adds to the cost of construction.[19] To get utilities to spend the money for additional efficiency improvements will necessitate higher prices for electricity or restrictions of carbon emissions or both.

§ 1(b). Technologies That Enhance the Potential for Carbon Sequestration

§ 1(b)(1). Integrated Gasification Combined Cycle Technology

IGCC technology is a new application of coal gasification technology that was used to light street lamps which led to the "gaslight era" of the 1890s. In the IGCC process coal is fed to a gasifier where it is partly oxidized by steam under pressure. By reducing oxygen in the gasifier, carbon in fuel is converted to gas that is a mixture of hydrogen and carbon monoxide (syngas). Hydrogen sulfide, which is an impurity, can be removed as elemental sulfur or as sulfuric acid and sold. Inorganic ash and metals drop out as slag, which is stable and may be used in construction materials.[20] The process also can be used to provide process or heating steam, which further increases overall efficiency.[21] IGCC technology removes emission-forming constituents from the syngas before combustion, which results in low levels of criteria pollutants and volatile mercury being released from the gas turbine's exhaust.[22] IGCC technology allows coal to be used while producing emissions comparable to a natural gas combined cycle (NGCC) facility.[23]

An electric power plant's efficiency can be improved by using a combined cycle. The exhaust gas temperature from the combustion turbine of approximately 1000 degrees F is used to produce high temperature steam that drives a separate turbine. Combustion turbines have peak performance efficiencies in the mid-thirty percent range, and steam turbines can be used to produce electricity at an efficiency in the upper thirty percent range. The combined efficiency of a combined cycle plant using natural gas is approximately fifty-nine percent.[24] IGCC plants could

[18] Bennett, *supra* note 16, at 1.
[19] *Id.* at 1.
[20] FutureGen Alliance, Coal Gasification, available at http://www.futuregenalliance.org/technology/coal.stm (last visited Dec.1, 2010.
[21] *Id.*
[22] Clean-Energy.us, *About IGCC Power,* available at http://www.clean-energy.us/facts/igcc.htm (last visited Feb. 11, 2010).
[23] *Id.*
[24] This is based on 35% turbine efficiency plus .37 (efficiency of the steam cycle) times .65 (the percentage of heat remaining in the exhaust) which produces an overall efficiency of 59%.

achieve this efficiency despite the lower heat value of the gas generated from coal combustion, but the amount of fuel burned must be increased to provide the necessary heat input.[25]

To enable pre-combustion capture of CO_2 in IGCC applications, the syngas (CO and H_2) is further processed in a water gas shift reactor. In the water gas shift reactor, the CO is converted to CO_2 while additional H_2 is produced, increasing the CO_2 and H_2 concentrations. The CO_2 can then be separated from the H_2 using an acid gas removal system. CO_2 capture should be easier to achieve -- and therefore less expensive -- for pre-combustion capture than for post-combustion capture because CO_2 is present at much higher concentrations in syngas (after the water gas shift) than in flue gas, and because the syngas is at higher pressure than flue gas. Capturing pre-combustion CO_2 raises the cost of electricity by thirty percent or an increase from an average of 7.8 cents per kilowatt hour (KWh) to about 10.2 cents per KWh.[26] However, IGCC plants are more expensive to build. Nonetheless IGCC has the promise of being able to significantly reduce costs in the future.

In 2002 there were 160 commercial IGCC plants, built or planned, in twenty-eight countries. The United States has four operating IGCC plants at full-scale operation. Only two are electric power generating facilities,[27] which use gasification technology to produce synthetic gas to fuel a gas turbine.[28] The efforts to develop IGCC facilities in the United States were discussed in a previous publication.[29] However, in 2010 the Department of Energy announced it was redesigning the FutureGen project. Rather than funding a prototype IGCC facility, DOE was going to support development of CCS technology that can be used at existing pulverized coal facilities. It will provide $1 billion to repower the existing 200 MW Unit 4 in

[25] F.J. Brooks, *GE Gas Turbine Performance Characteristics,* 1,7 (G.E. Industrial & Power Systems GER-3567E) (Oct. 2000).

[26] U.S. Dept. of Energy, National Energy Technology Laboratory, *Carbon Sequestration* CO_2 Capture, available at http://www.netl.doe.gov/technologies/carbon_seq/core_rd/co2capture.html (last visited Dec. 3, 2010).

[27] In 1983 Eastman Chemical Company began commercial operation of two Texaco (now GE Energy) gasifiers at its primary chemical manufacturing facility in Kingsport, Tennessee. *See* http:www.clean-energy.us/success/Eastman.htm (last visited Feb. 12, 2010). The process converts bituminous coal into methanol and then to acetyl chemicals produced downstream at the chemical plant. Bill Trapp, Nate Moock, and David Denton, *Coal Gasification: Ready for Prime Time*, POWER MAGAZINE (March 2004). Eastman claims its engineers have experience working on or operating over twenty gasification facilities worldwide including "a number of petcoke and coal-fed gasifiers." Eastman Operational Expertise: The Eastman Advantage, *available at* http://www.eastman.com/Company/Industrial_Gasification/Pages/Operational_Expertise.aspx (last visited Dec. 3, 2010). The Dakota Gasification Company has the only commercial-scale coal gasification plant in the United States that manufacturers natural gas. It is located near Beulah, North Dakota and has been in operation since 1984.

[28] Bill Trapp, Nate Moock, and David Denton, *Coal Gasification: Ready for Prime Time,* POWER MAG., Mar. 2004., available at http://www.clean-energy.us/projects/eastman_power_magazine.htm (last visited Dec.3, 2010).

[29] Arnold W. Reitze, Jr., *Electric Power In a Carbon Constrained World,* 34 WILLIAM & MARY ENVTL L. & POL'Y REV. 821, 848-854 (2010) [hereinafter Reitze, *Carbon Constrained*].

Meredosia, Illinois, with advanced oxy-combustion technology, which will be the world's first commercial scale oxy-combustion power plant. The funding will come through the American Recovery and Reinvestment Act.[30]

§ 1(b)(2). Oxy-Coal Combustion

Oxyfuel technology is applicable to new supercritical power plants and is part of the process used in the cutting edge IGCC technology, but the process also can be retrofitted on existing coal-fired or oil-fired power plants.[31] The oxy-fuel system uses relatively pure oxygen rather than air for combustion. An on-site unit separates air into nitrogen and oxygen prior to combustion.[32] This is both costly and energy intensive.[33] The nitrogen is released to the atmosphere, and the oxygen is sent to the boiler to support combustion. Because nitrogen is removed prior to combustion much less nitrogen oxide is produced by this technology.[34] The use of oxygen, rather than air, to support combustion will cause the combustion temperature to exceed the design capability of the furnace. For this reason, some CO_2 in the flue gas is returned to the boiler to lower the temperature of combustion. New furnaces could potentially be designed to function at the higher temperatures of a pure oxygen environment, but such furnaces would require the use of new materials and new designs for heat transfer.[35]

Regardless of the technology used to combust fossil fuel the CO_2 in the flue gas must be concentrated and pressurized before it is sequestered. Because oxy-combustion produces a flue gas with higher concentrations of CO_2 than conventional combustion, its capture costs are reduced, but that does not mean the capital cost will not be higher. Moreover, the flue gas still contains numerous contaminants.[36] To prevent corrosion of pipelines and to comply with the likely specifications for sequestration, acidic impurities need to be removed from the CO_2 stream prior to its being transported. The technology to accomplish this is still being developed. Other captured emissions that are liquids or solids are treated or sent to land disposal sites.[37]

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[30] Pub. L. No. 111-5. *See* Steven D. Cook, *Energy Department Commits $1 Billion To FutureGen2 Carbon Capture Project,* 41 Env't Rep. (BNA) 2183 (Oct. 1, 2010); Steven D. Cook, *Department of Energy Awards $1 Billion To FutureGen Carbon Sequestration Project,* 41 Env't Rep. (BNA) 1820 (Aug. 13, 2010).

[31] *Air Products' Oxyfuel Combustion and CO_2 Capture Technology, available at* http://www.airproducts.com/Responsibility/EHS/EnvironmentalProtection/enhanced_oil_recovery.htm (last visited Dec. 3, 2010).

[32] Air contains 76.85 % nitrogen by weight and 79.0% nitrogen by volume. BABCOCK & WILCOX CO., STEAM ITS GENERATION AND USE 4-4 (1960).

[33] *Id.*

[34] *Id.*

[35] *See generally* H. Farzan, *et al., State of the Art of Oxy-Coal Combustion Technology for* CO_2 Control from Coal-Fired Boilers, (Babcock & Wilson Co. 2007).

[36] Babcock & Wilcox Co., *Oxy-Coal Combustion Overview* (2007).

[37] *Id.*

§ 1(b)(3). Chemical Looping

In combustion using chemical looping an air reactor is used to transfer the oxygen in air to a reduced metal or metal oxide at temperatures of 800 to 1000 degrees C. The metal oxide is then delivered to a fluidized bed fuel reactor where coal or coal-derived syngas reacts with the metal oxide at high temperature. The air reactor and fuel reactor are each a closed loop where air and fuel never contact one another. The metal oxide delivers the oxygen needed for combustion and the metal oxide, minus oxygen, is returned to the air reactor. The fuel reactor releases heat in a flameless combustion process with pure CO_2 and water as the products of the reaction. The chemical looping process does not require expensive air separation to produce oxygen for combustion that is needed for oxyfuel or IGCC technology. With chemical looping the CO_2 is more concentrated than in the gas streams of other combustion processes and can be sequestered at lower costs. Unfortunately, the technology is only at the laboratory scale of development.[38]

§ 2. Carbon Sequestration

Carbon sequestration may be accomplished through storage in a geologic depository or by using a biologic process in which carbon dioxide is removed from the atmosphere by plants.[39] Biological sequestration is a well-established and cost effective way to sequester carbon, but it is difficult to quantify the benefits. California has developed accounting rules for use in carbon capture projects involving improved forestry practices, and the approaches used for these applications may be useful when developing geologic sequestration projects.[40] However, it will be some time in the future before sequestration in geologic formation is proven to be an effective and economical way to reduce CO_2 emissions to the atmosphere. A major benefit from effective sequestration is that America's abundant supply of coal could be utilized without the adverse environmental impacts associated with CO_2 emissions. Risks from geologic sequestration that have been identified include changes in soil chemistry that could harm the ecosystem, effects on water quality due to acidification, effects of geologic stability, and the potential for large releases that could harm or suffocate people and animals.[41] Sequestration technology deployment will require regulation of site selection and development, carbon dioxide transport, operational injection of CO_2, post-injection

[38] University of Utah, Institute for Clean and Secure Energy, *Combustion Chemical Looping* (2008).
[39] It may also be possible to inject CO_2 into soil, a process known as soil carbon sequestration, to help reduce atmospheric CO_2 concentrations. *See* Tripp Baltz, *USDA Research Service Begins Study Of Carbon Storage in Soil in Wyoming,* 40 Env't Rep. (BNA) 1709 (July 17, 2009).
[40] Carolyn Whetzel, *Sierra Pacific Industries Launches 60,000 Acre Sequestration Project,* 40 Env't Rep. (BNA) 2371 (Oct. 9, 2009).
[41] *International Climate Study Examines Feasibility of CO_2 Storage,* XVI CLEAN AIR REPORT (Inside EPA) 4:4 (Feb. 24, 2005).

monitoring and closure. In addition financial responsibility must be established in order to provide long-term stewardship.

§ 2(a). CO_2 Capture

CCS begins by separating CO_2 from other gases, which may be done before or after fuel is combusted.[42] Pre-combustion capture was discussed in § 1(b). Post-combustion capture is the more important technology because it could be used to capture CO_2 from conventional fossil fuel facilities. CO_2 may be captured and sequestered from fossil-fueled power plants or from industrial processes including the production of hydrogen and other chemicals, the production of substitute natural gas, and the production of transportation fuel. Post-combustion carbon capture in the recent past has received about one-tenth the funding from Department of Energy (DOE) as has been provided for the IGCC program, which may be a reason for the lack of advancement for post-combustion carbon capture technology.[43] But the federal government has been increasing its funding for research concerning CO_2 capture. On September 16, 2009, DOE announced that more than $62 million in funding from the American Recovery and Reinvestment Act would be used to boost carbon capture and storage research and development.[44] This act would bring the funding for carbon capture and storage projects to $2.4 billion.[45]

The majority of the costs of CCS are incurred in separating and capturing CO_2 from flue gas.[46] Carbon capture from the flue gas of coal-burning power plants will be more expensive than the carbon capture used by industrial processes that involve more concentrated streams of CO_2. The concentration of CO_2 in conventional post-combustion gas streams means that large volumes of flue gas must be processed to remove their conventional pollutants, which can limit the effectiveness of some carbon capture processes. Conventional power plant emissions are about 13% to 15% CO_2 by volume, which increases the energy requirements needed to remove a given quantity of CO_2 from the gas stream compared to gas streams with higher concentrations of CO_2. It also limits the use of solvents such as monoethanolamine that are commonly used to remove CO_2 from natural gas because the diluted concentration makes the use of solvents too costly.[47] An Intergovernmental Panel on Climate Change (IPCC) report estimates the cost of

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[42] UNITED STATES GOVERNMENT ACCOUNTABILITY OFFICE, FEDERAL ACTIONS WILL GREATLY AFFECT THE VIABILITY OF CARBON CAPTURE AND STORAGE AS A KEY MITIGATION OPTION 10 (Sept. 2008) [GAO-08-1080] [hereinafter GAO].
[43] GAO, *id.* at 45.
[44] U.S. Dept. of Energy, *New Funding from DOE Boosts Carbon Capture and Storage Research and Development,* available at http://www.energy.gov/8016.htm (last visited Dec.3, 2010).
[45] U.S. Dept. of Energy, *Secretary Chu Announces $2.4 billion in Funding for Carbon Capture and Storage Projects,* available at http://www.energy.gov/7405.htm (last visited Dec. 3, 2010).
[46] *See* http://www.netl.doe.gov/technologies/carbon_seq/index.html (last visited Dec. 3, 2010).
[47] GAO, *supra* note 45, at 18.

carbon capture at 1.8 to 3.4 cents/KWh for a pulverized coal plant; 0.9 to 2.2 cents/kWh for an IGCC plant; and 1.2 to 2.4 cents/KWh for a natural gas combined-cycle power plant.[48]

If nitrogen in the air is removed prior to combustion, such as occurs in both the oxyfuel and IGCC process, it is less costly to separate a given amount of CO_2 than is the case with conventional power plants because its concentration is higher, therefore less energy is required to remove CO_2.[49] If the technology for removal can be improved, carbon capture could become less energy intensive, which would lower the cost of CCS.[50]

After the CO_2 is removed from the exhaust gas stream at either a conventional or an IGCC facility, it must be concentrated the into a stream of nearly pure CO_2, and then compressed to convert it from gas to a supercritical fluid before it is transported to the injection site.[51] This reduces the efficiency of the electric generation process because of the energy required to liquefy CO_2. It is estimate that carbon capture from a new IGCC plant would increase the cost of electricity production by less than half the cost of carbon capture from a new pulverized coal plant because the higher concentration of CO_2 in the IGCC gas stream lowers the energy requirements for liquefying the CO_2, although capital costs could be higher.[52] However, pulverized coal plants generate 99 percent of the electricity produced in the U.S. from burning coal, which reduces the importance of the potential benefits of IGCC at this time.[53]

Carbon capture from most conventional power plants that use pulverized coal would require post-combustion capture using technologies such as amine-based chemical solvents, such as aqueous methoethanolanimine ("MEA") although such technologies have a parasitic power demand, require a significant amount of additional cooling water, and have not been demonstrated at a large-scale adequate for a coal-fired power plant..[54] In 2009 DOE stated CCS will increase the cost of electricity from a new pulverized coal plant by about 75% and will increase the cost of electricity from a new advanced gasification-based plant by about 35%.[55] Overall CO_2 sequestration costs are estimated at $25 to $90 a metric ton, depending on the source.[56] The U.S. Department of Energy estimates that sequestration from an IGCC

[48] IPCC SPECIAL REPORT ON CARBON DIOXIDE CAPTURE AND STORAGE SUMMARY FOR POLICYMAKERS, available at http://www.ipcc.ch/pdf/special-report/srccs/srccs_summaryforpolicymakers.pdf (last visited Dec. 3, 2010).
[49] Institute for Clean and Secure Energy, Oxyfuel, University of Utah (2009).
[50] GAO, *supra* note 45, at 31.
[51] *Id.* at 22.
[52] *Id.* at 19.
[53] http://www.netl.doe.gov/technologies/carbon_seq/core_rd/co2capture.html (last visited Dec.3, 2010).
[54] U.S. DEPT. OF ENERGY, NATIONAL ENERGY TECHNOLOGY LABORATORY, DOE/NETL CARBON DIOXIDE CAPTURE AND STORAGE RD&D ROADMAP 23,25,26 (DEC. 2010)
[55] U.S. Dept. of Energy, *Carbon Capture and Storage R & D Overview,* available at http://www.fossil.energy.gov/programs/sequestration/overview.html (last visited Dec. 3, 2010).
[56] IPCC SPECIAL REP., *supra* note 51.

facility will increase the average cost of electricity from 7.8 cents per KWh to 10.2 cents per KWh.[57] A report prepared at the University of Utah found the cost of carbon capture to be about $40 per ton and underground storage costs $10 per ton, which, as previously mentioned, would add 7.5 cents to the cost of a KWh.[58] This cost would be added to the average delivered cost in the United States of 8.9 cents per KWh.[59] The capital costs of adding capture technology to a 400-MW power plant is estimated at $1 billion.[60] The added cost is projected by an MIT study to nearly double the cost of a KWh of electricity.[61] This may encourage the use of funding mechanisms that hide the costs of CCS such as investment tax credits, carbon sequestration credits, subsidies funded from a cap-and-trade program, federal loan guarantees, and federal financing.[62]

A report by the IPCC estimated that CCS would increase the cost of a KWh of electricity from a natural gas combined cycle plant by one to four cents. CCS for CO_2 from a pulverized coal plant would increase costs by two to four cents, and the cost increase for an IGCC plant would be one to three cents a KWh. Thus, CCS, according to the IPCC, would increase the cost of producing electricity by about 30% to 60%. The IGCC study also says that since none of these technologies have used CCS at a full-scale facility, the costs of these systems cannot be stated with a high degree of confidence.[63] The cost of sequestration will be added to the costs of updating an inadequate transmission system, updating or replacing aging generation assets, investing in advanced metering equipment, expanding the electric power generating capacity to deal with power demand, and investing to meet renewable portfolio requirements. For this reason, a presidential task force report issued August 12, 2010, says that placing a price on carbon emissions is crucial if CCS is to be quickly deployed.[64]

§ 2(b). Carbon Dioxide Transport

After CO_2 is captured it must be transported to a storage site for underground injection. Even with relatively convenient access to storage reservoirs,

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[57] http://www.netl.doe.gov/technologies/carbon_seq/core_rd/co2capture.html (last visited Dec.3, 2010). This appears to be an estimate at the lower bound of DOE's range of a sequestration cost of between 2.5 and 9 cents/kwh of additional cost for electricity.
[58] Stephen Sicilliano, *Sequestration Called Best Way to Achieve Short-Term Reductions of Carbon Emissions,*38 Env't Rep. (BNA) 2286 (Oct. 26, 2007).
[59] GAO, *supra* note 45, at 23.
[60] Andrew Childers, *Funding, Regulatory Certainty Questions Linger Over Carbon Capture Technology,* 41 Env't Rep. (BNA) 1056 (May 14, 2010).
[61] THE FUTURE OF COAL, SUMMARY REPORT 19 (Massachusetts Institute of Technology 2007)
[62] Steven D. Cook, *Dorgan Report See Minimum of $110 Billion Needed to Deploy Carbon Capture, Storage,* 40 Env't Rep. (BNA) 2762 (Dec. 4, 2009).
[63] Intergovernmental Panel on Climate Change, Working Group III, *Carbon Dioxide Capture and Storage* 10 (2005)
[64] *Report of the Interagency Task Force on Carbon Capture and Storage* (Aug. 12, 2010), available at http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf (last visited Dec. 1, 2010).

transportation will be costly because a 1,000 MW plant will consume about 13,000 tons of coal each day.[65] The weight of CO_2 that will need to be shipped will be more than double the weight of the coal that was used by the power plant, with the exact weight being dependent on the moisture content and carbon content of the fuel.[66] Thus, a 1,000 MW power plant using 13,000 tons a day of Powder River Basin coal would produces about 26,824 tons of CO_2 per day.[67] CO_2 in the super critical state used for injection has a density of 0.03454 cubic feet per pound or about 69 cubic feet per ton.[68] Thus, a modern power plant could be expected to need to transport liquid CO_2 in an amount of over 1.85 million cubic feet each day, which is equivalent to the volume of a football field over 32.13 feet deep.[69] Electrical generation in 2007 in the United States produced 2,342.0 million metric tons of CO_2.[70] This will result in the generation of 165,407 million cubic feet a year, which is a column one square mile at its base and over 1.12 miles high.[71]

In addition to the significant engineering and economic issues concerning transporting CO_2, carbon sequestration raises legal issues concerning how the CO_2 will be transported and the potential liability for transportation mishaps. CO_2 will be compressed into a supercritical fluid and transported to a site where it can be injected far below the ground. It is expected that pipelines will be the primary method of transporting CO_2 to a sequestration site.

There are approximately 3,600 miles of pipeline in the U.S., primarily in Wyoming and Texas, that are primarily used to transport CO_2 to oil fields for enhanced oil recovery, but if large scale CCS is to occur pipeline construction efforts

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65 *See* Power 4 Georgians, http://power4georgians.com/wcpp.aspx (last visited Dec. 3, 2010).

66 Coal is a mixture of carbon, hydrogen and oxygen molecules with carbon making up about 90% of the weight of a typical coal molecule, but coal also contains impurities, in the case of Powder River Basin coal about 74.1% of dry coal is carbon, but the coal consumed is wet with a 24% moisture content. The carbon in the coal combines with oxygen in the air to produce carbon dioxide that weighs 3.664 times the weight of the carbon based on the atomic weights of oxygen and carbon. BABCOCK & WILCOX, *supra* note 35, at 2-4, 2-8, tbl.10 (37th ed. 1960); B.D. Hong & E.R. Slatick, *Carbon Dioxide Emission Factors for Coal,* DOE, Energy Information Administration, available at http://www.eia.doe.gov/cneaf/coal/quarterly/co2_article/co2.html (last visited Dec. 3, 2010).

67 For a Powder River Basin coal, 13,000 tons of coal per day minis its moisture content multiplied by its carbon content is the weight of the carbon and multiplied by the relative weight of carbon dioxide will produce 26,824 tons per day of carbon dioxide (13,000 x .76 x .741 x 3.664). Calculated from data found in BABCOCK & WILCOX, *supra* note 35, at 2-8, 2-9.

68 CHEMICAL ENGINEER HANDBOOK, 5TH. ed. 3-162 (Robert H. Perry ed. 1953). The IGCC Special Rep. provides a range of numbers, but says the density is 1032 kilograms per cubic meter at 20 degrees C and 19.7 bar pressure, which converts to 64.4 pounds per cubic foot.

69 A NFL football field is 360 by 160 feet, which is 57,600 square feet. *See* http://www.sportsknowhow.com (last visited Dec. 3, 2010). A power plant's production of 26,824 tons per day of carbon dioxide at 69 cubic feet per ton is 1.85 million cubic feet of super critical carbon dioxide. Divided by 57,600 gives a depth of 32.13 feet.

70 2010 INVENTORY OF U.S. GREENHOUSE GASES, EXECUTIVE SUMMARY, *supra* note 6, at ES-8.

71 5,280 x 5,280 =27.88 million sq. ft. 165, 407 million/ 27.88 million = 5932.8 ft or 1.12 miles.

will be needed to create a dedicated pipeline network.[72] The size and configuration of the pipeline network that will be needed cannot be determined until the number, size and characteristics of the sequestration sites are known. A University of California study published in 2004 estimated the cost of construction in 2002 dollars at about $800,000 per mile, and the costs have increased substantially since the study was completed.[73] However, 95 percent of the 500 largest stationary sources are within 50 miles of a potential CO_2 reservoir. Estimated storage capacity in the United States is over 3,500 Gigatons of CO_2 (Gt CO_2), although the actual capacity may be lower once site-specific technical and economic considerations are addressed. Even if only a fraction of that geologic capacity is used, CCS could play an important role in mitigating US GHG emissions.[74]

The federal authority to regulate pipelines that are used exclusively for CO_2 transport is exercised by the U.S. Surface Transportation Board.[75] The Board has authority to regulate the rates charged by pipeline companies, but it may only respond to complaints by third parties, and its authority is limited compared to the authority of the Federal Energy Regulatory Commission (FERC) to regulate natural gas and oil pipelines.[76] The Board has no authority to regulate pipeline construction, nor does it have eminent domain authority. It cannot require companies seeking to build pipelines to obtain certificates of public convenience and necessity such as FERC requires for the construction of interstate natural gas pipelines.[77] If pipelines are to be placed on federal land managed by the Bureau of Land Management (BLM), the provisions of the Federal Land Management Act (FLPMA) or the Mineral Leasing Act will apply.[78] The Mineral Leasing Act (MLA) imposes common carrier requirements, but FLPMA does not. It is not clear what rules would apply to pipelines carrying CO_2 for sequestration.[79] In addition a potential conflict exists because the Environmental Protection Agency (EPA) treats CO_2 as a pollutant under the Safe Drinking Water Act[80] while other agencies of the government treat CO_2 as a commodity.[81] This is not unusual. Many products that are used in commerce are subject to the requirements of statutes administered by EPA.

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[72] CAL. ENERGY COMM., GEOLOGIC CARBON SEQUESTRATION STRATEGIES FOR CALIFORNIA 25 (Sept. 2007). The Department of Transportation, National Pipeline Mapping System database does not allow the public to access the location of pipelines. *See* http://www.npms.phmsa.dot.gov (last visited Dec. 3, 2010).
[73] Paul W. Parformak & Peter Folger, *Carbon Dioxide (CO_2) Pipelines for Carbon Sequestration: Emerging Policy Issues,* CRS-12 (CRS Report for Congress, April 19, 2007).
[74] *Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells; Final Rule,* 75 Fed. Reg. 77,229, 77,234 (Dec. 10. 2010).
[75] The Surface Transportation Board was created by the Interstate Commerce Commission Termination Act of 1995 (P.L. 104-88). Its jurisdiction extends to pipelines transporting commodities other than water, oil, or natural gas (49 U.S.C. § 15301).
[76] CRS Report, *supra* note 76, at CRS-7.
[77] *Id.* at CRS-8. *See also* the Natural Gas Act, 15 U.S.C. §§ 717, *et seq.*
[78] 43 U.S.C. § 35; 30 U.S.C. § 185.
[79] CRS Report, *supra* note 76, at CRS-9
[80] *Id.* at CRS-11, citing the U.S. Envtl. Protection Agency, memorandum of July 5, 2006.
[81] *Id.* at CRS-10.

Safety regulations for CO_2 pipelines will be within the jurisdiction of the Department of Transportation's (DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) for pipelines that affect interstate commerce. The Hazardous Liquid Pipeline Act of 1979, as amended, regulates interstate pipelines and provides minimum standards for states that regulate intrastate pipelines.[82] PHMSA regulates the design, construction, operation and maintenance, and spill response planning for pipelines.[83] PHMSA applies nearly the same safety regulations to CO_2 pipelines as it applies to pipelines carrying hazardous liquids.[84] PHMSA will need to reevaluate its legal requirements for pipelines if a large-scale sequestration program is to develop, and it will need to deal with cross-jurisdictional issues involving multiple federal agencies as well as state regulatory agencies.

Siting approval is based primarily on state law, which is intertwined with local concerns and may involve a complex and protracted process.[85] If pipelines are to be constructed, "not in my backyard" (NIMBY) opposition should be expected. This issue was addressed in Montana, when H.B. 338 became law on April 16, 2009. It grants owners of pipelines transporting CO_2 common carrier status, which allows them to use eminent domain to acquire private property.[86]

It would appear that more comprehensive federal legislation is needed to establish which agency will regulate pipelines used for CO_2 transport.[87] Such legislation will need to address the planning and siting of CO_2 pipelines as well as provide for the promulgation of regulations concerning rates and terms of service for interstate CO_2 pipelines.

§ 2(c). Carbon Dioxide Storage

After CO_2 is transported to an underground storage location, under high pressure CO_2 becomes a liquid that is injected into underground geological formations and monitored.[88] There appear to be more than adequate geological formations to use as potential storage reservoirs, although detailed study will need to be performed prior to using a specific formation as a CO_2 repository.[89] The Energy Independence and Security Act of 2007 requires the U.S. Geological Survey (USGS) to develop a methodology to determine the capacity for CO_2 sequestration in the

[82] 49 U.S.C. § 601.
[83] 49 C.F.R. § 190, 195-199.
[84] CRS Report, *supra* note 76, at CRS-16.
[85] CRS Report, *supra* note 76*,* at CRS-9.
[86] Perri Knize, *Montana Governor Signs Measures Easing Path to Carbon Sequestration, Transport,* 40 Env't Rep. (BNA) 1202 (May 22, 2009). For more information on state regulation of CCS, *see* Arnold Reitze, Jr. & Marie Bradshaw Durrant, *State and Regional Control of Geological Carbon Sequestration*, (forthcoming 2011) [hereinafter *State CCS*].
[87] GAO, *supra* note 45, at 45.
[88] GAO, *supra* note 45, at 1.
[89] THE FUTURE OF COAL, *supra* note 64, at 44.

United States and to then assess the capacity.[90] On June 3, 2009, the Department of the Interior issued its report recommending a framework for identifying suitable CO_2 storage sites.[91] The report called for specific criteria for sequestration in oil and gas fields (depleted or operating), unminable coal seams, deep geological systems containing basalt formations, coalbed methane recovery sites and deep saline formations.[92] The Department of the Interior (DOI) report is more conservative in its estimates than DOE because it does not include coal deposits as potential sequestration sites; it only evaluates available sites that are 3,000 to 13,000 feet deep; and it limits evaluation to sites that can store two million cubic meters of CO_2 or more. This is the amount that could be emitted in a short time by a single coal-burning power plant. USGS does evaluate oil and gas reservoirs and saline formations. Saline formations are deep beneath the surface and often are filled with water with a high salt content that are topped with an impervious cap that prevents the loss of the sequestered CO_2.[93] They are the principal focus of long-term carbon sequestration efforts. Saline formations, according to the Congressional Budget Office, have eighty percent of the estimated geological storage capacity in the United States.[94] Issues of concern to the U.S. Geological Survey include the effect of sequestration on mineral extraction as well as surface activities such as grazing, recreation, and community development. Sites also need to be evaluated for their potential to induce earthquakes.[95]

CO_2 storage can be based on soluability trapping, hydrodynamic trapping, physical adsorbtion and mineral trapping. Solubility trapping involves salt water containing CO_2 sinking to the bottom of a rock formation. In hydrodynamic trapping physical trapping or geochemical trapping. With hydrodynamic trapping, the relatively buoyant CO_2 rises in the formation until it reaches a stratigraphic zone with low permeability, such as shale or carbonates, that inhibits migration of the CO_2 from the porous formations, such as sandstone, where it is stored. The pore spaces that will receive the CO_2 are rarely empty; they usually contain other gases and liquids, primarily brine, that will be displaced or have their pressure increased by the injection.[96] In physical adsorption CO_2 molecules are trapped at near liquid-

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[90] Pub. L. No. 110-140 (2007).
[91] U.S. Dept. of the Interior, *Framework for Geological Carbon Sequestration on Public Land* (June 3, 2009). In 2009, USGS also published a proposed, risk-based methodology for GS capacity estimation. USGS released a final report: A Probabilistic Assessment Methodology for the Evaluation of Geologic Carbon Dioxide Storage (USGS, 2010). The report is available at http://pubs.usgs.gov/of/2010/1127/.
[92] *Id.* at 4.
[93] Leora Falk, *U.S. Geological Survey Develops Methodology To Assess Carbon Dioxide Storage Potential,* 40 Env't Rep. (BNA) 618 (Mar. 20, 2009).
[94] CONG. BUDGET OFF., THE POTENTIAL FOR CARBON SEQUESTRATION IN THE UNITED STATES 12 (SEPT. 2007).
[95] Steven D. Cook, *Site Selection Criteria Recommended For Geologic Storage of Carbon Dioxide,* 40 Env't Rep. (BNA) 1292 (June 5, 2009).
[96] Alexandra B. Klass & Sara E. Bergan, *Carbon Sequestration and Sustainability,* 44 TULANE L. REV. 237, 248 (2008). Physical trapping can also occur as residual CO_2 is immobilized in formation pore spaces as disconnected droplets or bubbles at the trailing edge of the plume due to capillary forces. A portion of the CO_2 will dissolve from the pure fluid phase into native ground water and hydrocarbons. Preferential sorption occurs when CO_2 molecules attach to the surfaces of coal and

like densities on micropore wall surfaces of coal seams or shales. In mineral trapping CO_2 reacts chemically with minerals in the geological formation and forms solid minerals. Mineral trapping results in the most stable form of geological CO_2 sequestration[97] It is expected that the supercritical liquid CO_2 will be injected, using proven technology, at depths of over 800 meters (2,625 feet) into geological formations that will sequester it for hundreds to thousands of years.[98] CO_2 has been trapped for more than 65 million years under the Pisgah Anticline, northeast of the Jackson Dome in Mississippi and Louisiana (IPCC, 2005). Other natural CO_2 sources include the following geologic domes: McElmo Dome, Sheep Mountain, and Bravo Dome in Colorado and New Mexico.[99]

CO_2 injection is used to enhance oil recovery (EOR) and to force methane out of coal beds for recovery and use.[100] The oil and natural gas industry in the United States has over 35 years of experience of injection and monitoring of CO_2 in the deep subsurface for the purposes of enhancing oil and natural gas production.[101] We do not have much experience with injection on the scale that will be required for geological storage of CO_2 from electric power plants for time spans in excess of human civilization. Such storage will require dealing with the properties of flue gas from fossil-fuel combustion. That includes the relative buoyancy of CO_2, its mobility within subsurface formations, the corrosive properties of the gases in water, the impact of the impurities in the flue gas, and the large volume of material that will need to be injected.

It is estimated by the International Energy Agency that about 10,000 large-scale CCS projects will be needed by 2050 to limit global warming to three degrees Celsius by the end of this century. The four that have attracted the most attention are: Sleipner in the Norwegian North Sea and Snohvit in the Barents Sea, Norway that are operated by StatoilHydro; the Salah gas project in Algeria operated by BP, Somatrach and StatoilHydro; and the North Dakota/Canadian facility discussed below.[102] None of the four existing sequestration projects was designed for long-term storage. They all are used to enhance hydrocarbon recovery. Since 1996 the

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certain organic-rich shales, displacing other molecules such as methane. Geochemical trapping occurs when chemical reactions between the dissolved CO_2 and minerals in the formation lead to the precipitation of solid carbonate minerals (IPCC, 2005). The timeframe over which CO_2 will be trapped by these mechanisms depends on properties of the receiving formation and the injected CO_2 stream. 75 Fed. Reg. at 77,233.

97 RD7D ROADMAP, *supra* note 57, at 49.

98 U.S. Envtl. Protection Agency, EPA Proposes New Requirements for Geologic Sequestration of Carbon Dioxide (July 2008) [EPA 816-F-08-032]. At temperatures above supercritical temperature a material cannot be distinguished between its liquid or gas phase. The critical temperature for carbon dioxide is 88 degrees F.

99 75 Fed. Reg. at 77,234.

100 Cook, *Site Selection*, *supra* note 98.

101 75 Fed. Reg. at 77,234.

102 Rick Mitchell, *IEA Says 10,000 Large-Scale Projects Needed by 2050 to Meet Climate Goals,* 39 Env't Rep. (BNA) 2223 (Nov. 7, 2008); GAO, *supra* note 45, at 17; Alexandra B. Klass & Elizabeth J. Wilson, *Climate Change and Carbon Sequestration: Assessing a Liability Regime For Long-Term Storage of Carbon Dioxide,* 58 EMORY L. J. 103, 107, fn 7.

Sleipner project has captured about 3,000 metric tons of CO_2 per day from its natural gas extraction, and it is stored 800 meters under the North Sea's seabed in a saline reservoir.[103] Other projects include Otway in Australia (operating since 2008); Ketzin in Germany (operating since 2008); and Lacq in France (operating since 2009). Two projects that are anticipated to begin injection in the near future: CarbFix in Iceland (anticipated to commence injection in 2010) and Gorgon in Australia (anticipated to start in 2014).[104]

Some CO_2 is captured at natural gas plants, but it is not sequestered.[105] The only coal-burning facility in North America that sequesters CO_2 is the Great Plains Synfuels Plant in North Dakota, owned by the Dakota Gasification Company that is a subsidiary of Basin Electric Cooperative. It is a synthetic natural gas facility where coal is gasified to make methane, and CO_2, sulfur dioxide and mercury are removed from the gas stream. The gas stream, which is 96% CO_2, is pressurized until it is in a supercritical state, which results in the gas becoming as dense as a liquid, but it flows like a gas. It is then shipped 205 miles by pipeline to an oil field near Weyburn, Saskatchewan, Canada where it is injected into one of the thirty-seven injection wells and is used to enhance oil recovery. The facility began sequestrating CO_2 in 2000. It handles 8,000 metric tons of CO_2 each day and is expected to eventually store 20 million tons 1,400 meters underground.[106]

The U.S. Department of Energy on May 15, 2009 announced $2.4 billion from the American Recovery and Reinvestment Act will be used to accelerate CCS development and deployment.[107] President Obama announced on February 3, 2010, that he was establishing an interagency task force to speed the development of CCS technologies, and its primary mission was to get five to ten commercial-scale sequestration projects operational by 2016.[108] In June 2010, DOE granted up to $612 million to fund CCS projects out of funding from the American Recovery and Reinvestment Act of 2009.[109] On September 7, 2010, DOE announced it had selected 22 projects to share $575 million in federal funding to accelerate CCS development.[110]

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[103] GAO, *supra* note 45, at 28. A list of the sequestration projects throughout the world is maintained by the IEA available at http://co2captureandstorage.info/co2db.php (last visited Dec. 3, 2010).
[104] 75 Fed. Reg. at 77,238.
[105] GAO, *supra* note 45, at 17.
[106] *International CO_2* sequestration success story, available at http://www.basinelectric.com:80/Gasification/CO2/index.html (last visited Dec. 3, 2010).
[107] U.S. Department of Energy, *Secretary Chu Announces $2.4 billion in Funding for Carbon Capture and Storage Projects* (May 15, 2009), available at http://www.energy.gov/7405.htm (last visited Dec. 3, 2010).
[108] Lynn Garner, *Obama Establishes Interagency Task Force To Expedite Carbon Capture at Power Plants,* 41 Env't Rep. (BNA) 263 (Feb. 5, 2010).
[109] *More Than $600 Million in Stimulus Grants Support Industrial Carbon, Capture, Storage,* 41 Env't Rep. (BNA) 1356 (June 18, 2010). *See also* Steven D. Cook, *DOE Seeks Comment on Assessments Of Carbon Capture Projects in Two States,* 41 Env't Rep. (BNA) 1298 (June 11, 2010).
[110] Alan Kovski, *Funds Awarded for Research, Development On Carbon Capture, Improved Combustion,* 41 Env't Rep. (BNA) 1995 (Sept. 10, 2010).

DOE's National Energy Technology Laboratory (NETL) is developing and/or operating GS projects. The seven Regional Carbon Sequestration Partnerships (RCSPs) are conducting pilot and demonstration projects involving site characterization (including injection and confining formation information, core data and site selection information); well construction (well depth, construction materials, and proximity to underground sources of drinking water (USDWs)); frequency and types of tests and monitoring conducted (on the well and on the project site); modeling and monitoring results; and injection operation. EPA and DOE are funding the Lawrence Berkeley National Laboratory's (LBNL) work concerning potential impacts of CO_2 injection on ground water aquifers and drinking water sources.[111] EPA's Office of Research and Development (ORD) National Center for Environmental Research (NCER) provides extramural CCS research grants. In the fall of 2009, NCER awarded six Science To Achieve Results (STAR) grants to recipients from major universities and institutions. One of the awards was granted to the University of Utah for integrating design, monitoring, and modeling of GS to assist in developing a practical methodology for characterizing risks to USDWs.[112]

To have viable carbon storage will require overcoming many technical problems, but it also will require cost effective environmental protection requirements, settling the ownership issues concerning carbon storage, and resolving the issue of long-term liability. Perhaps the first step will be to define what CO_2 is for the purposes of a CCS program. The Interstate Oil and Gas Compact Commission (IOGCC) has defined CO_2 as "anthropogenically sourced CO_2 of sufficient purity and quality as to not compromise the safety and efficiency of the reservoir containing the CO_2."[113] While large-scale CCS has not yet occurred, a body of law has developed concerning EOR and natural gas storage in geologic reservoirs that can be used to help shape an appropriate legal regimen for CCS.

EOR usually involves a unitized operation where all owners receive a portion of the benefits from EOR. This reduces the potential conflicts since all property owners are participants. If operations have not been unitized the operator would have a significant exposure to tort or property-based litigation.[114] Natural gas storage requires compliance with the state law on ownership of the depleted oil and gas reservoir pore space.[115] Under the Natural Gas Act of 1938 interstate pipelines have eminent domain powers that apply to subsurface storage facilities.[116] Storage of natural gas requires payment to the subsurface owner for the fair market value of

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[111] 75 Fed. Reg. at 77,238.
[112] *Id.*
[113] The Interstate Oil and Gas Compact Commission, *Storage of Carbon Dioxide in Geologic Structures, A Legal and Regulatory Guide for States and Provinces* 10 (2007).
[114] Victor B. Flatt, *Paving the Legal Path for Carbon Sequestration From Coal,* 19 DUKE ENVTL L. & POL'Y FORUM 211, 231 (2009).
[115] *See* Elizabeth J. Wilson & Mark A. de Figueiredo, *Geologic Carbon Dioxide Sequestration: An Analysis of Subsurface Property Law,* 36 ENVTL. L. REP. (ELI) 10114, 10117 (2006).
[116] 15 U.S.C. § 717.

the right to store natural gas, with the value to be determined by state law; "but the law of valuation remains unclear in most states and is largely undecided."[117]

§ 3. Federal Legal Requirements Applicable to Carbon Sequestration

The legal requirements imposed on the electric power industry will determine whether CCS becomes a viable control technology. The estimates of the cost of CCS range from $15 to $50 per metric ton of CO_2 sequestered using IGCC technology. For natural gas combined cycle plants the cost estimates range from $20 to $70 per metric ton. For pulverized coal plants the estimates are about $30 a ton.[118] But even if the price of CO_2 emissions is pegged at $30 a ton through legislation, such as cap-and-trade, it would take many years for industry to adopt CCS and many more years for the technology to be commonly utilized.[119] Environmental laws also affect decisions concerning CCS by changing the economic climate for electricity production. More stringent controls on conventional air pollutants, toxic air emissions and potential new controls on fly ash disposal will increase the cost of coal-fired electric power generation. This will make alternative methods of electric power generation such as nuclear and renewable sources more attractive, while also making CCS a more economically defensible choice for electric power companies.

§ 3(a). Safe Drinking Water Act (SDWA)

The SDWA part C requires EPA to establish minimum requirements for State underground injection control (UIC) programs that regulate the subsurface injection of fluids onshore and offshore under submerged lands within the territorial jurisdiction of States.[120] SDWA is designed to protect the quality of drinking water sources in the US and prescribes that EPA issue regulations for State UIC programs that contain "minimum requirements for effective programs to prevent

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[117] Flatt, *supra* note 117, at 237 (citing Elizabeth J. Wilson & Mark A. de Figueiredo, *Geologic Carbon Dioxide Sequestration: An Analysis of Subsurface Property Law, 36* Envtl L. Rep. 10114, 10116-18 (2006)).

[118] Congressional Budget Office, *The Potential for Carbon Sequestration in the United States* 17, 20 (Sept. 2007).

[119] *Id. at 20.*

[120] SDWA 1421 *et seq.,* 42 U.S.C. § 300h *et seq.* The chief goal of any federally approved UIC program is the protection of USDW. This includes not only those formations that are presently being used for drinking water, but also those that can reasonably be expected to be used in the future. EPA has defined through its UIC regulations that USDWs are underground aquifers with less than 10,000 milligrams per liter (mg/L) total dissolved solids (TDS) and which contain a sufficient quantity of ground water to supply a public water system. 40 C.F.R. § 144.3.

underground injection which endangers drinking water sources."[121] Underground injection of CO_2 waste streams has led to new regulations under the SDWA to address the risks presented by this emerging technology. For example, the pressure created by underground injection could push brine through geological formations into drinking water sources, which could render them unusable. When CO_2 contacts water, acids could form that would leach minerals (e.g. arsenic, lead) and organic compounds from the rock formations contaminating ground water. This concern could be exacerbated by the contaminants found in the injected waste streams, such as hydrogen sulfide or mercury.[122]

EPA initially promulgated regulations in 1980, when the Agency defined five classes of injection wells.[123] Today the regulations apply to over 800,000 injection wells nationwide.[124] Class I wells are used to inject hazardous waste below sources of drinking water.[125] Two of the classes are applicable to geological sequestration. Class II wells are those that inject fluids (e.g., CO_2 or brine) to enhance conventional oil or natural gas production or store hydrocarbons that are liquid at standard temperature and pressure. Class II CO_2 injection wells designated for EOR and enhanced gas recovery (EGR) technologies, collectively referred to as enhanced recovery (ER), are used in oil and gas reservoirs to increase production. Injection of CO_2 is one of several ER techniques used to increase oil and gas recovery by re-pressurizing the reservoir, and in the case of oil, by also increasing its mobility.[126] As of 2008, there were 105 CO_2-EOR projects within the US.[127]

Class V injection wells are those not included in Class I, II, III, or IV.[128] Among the wells covered by Class V are injection wells used in experimental technologies.[129] In 2007, EPA issued technical guidance to assist State and EPA Regional UIC programs in processing permit applications for pilot and other small-scale experimental GS projects.[130]

A number of CO_2 injection projects were permitted as Class V experimental technology wells for the purpose of testing GS technology. EPA stated that the UIC

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[121] 42 U.S.C. § 300h(b)(1) (West 2010).
[122] Klass & Bergan, *supra* note 99, at 248.
[123] 40 C.F.R. § 144.6 (2010).
[124] 75 Fed. Reg. 77,237 (Dec. 10, 2010).
[125] 40 C.F.R. § 144.6(a) (2010).
[126] 75 Fed. Reg. 77,244 (Dec. 10, 2010).
[127] *Id.* The majority (58) of the ER projects are located in Texas, and the remaining projects are located in Mississippi, Wyoming, Michigan, Oklahoma, New Mexico, Utah, Louisiana, Kansas, and Colorado. CO_2 -EOR projects recovered 6.5% of total domestic oil production in 2008. A total of 6,121 CO_2 injection wells among 105 projects were used to inject 51 million metric tons of CO_2. *Id.*
[128] 40 C.F.R. § 144.6(e).
[129] 40 C.F.R. § 144.81(14).
[130] UIC Program Guidance #83: Using the Class V Experimental Technology Well Classification for Pilot Carbon GS Projects (USEPA, 2007) provides recommendations for permit writers regarding the use of the UIC Class V experimental technology well classification at demonstration GS projects while ensuring USDW protection.

Program Guidance #83 continues to apply to experimental projects (as long as the projects continue to qualify as experimental technology wells under the guidelines described in the guidance) and to future projects that are experimental in nature. The Agency is preparing additional guidance for owners or operators and Directors regarding the use of the Class V experimental technology well classification for GS following the final rule of December 10, 2010.[131]

EPA's proposed rule governing underground injection of carbon dioxide under the SDWA was promulgated July 25, 2008.[132] The final rule was promulgated December 10, 2010, with an effective date of January 10, 2011.[133] The rule applies to owners or operators of wells that will be used to inject CO_2 into the subsurface for the purpose of long-term storage. It creates a new Class VI category for wells used for CCS as an addition to the five classes of wells that already require permits. The rule applies to subsurface geologic sequestration of a gaseous, liquid, or supercritical CO_2 stream. It does not apply to CO_2 capture or transport.[134] The rule sets minimum technical criteria for Class VI wells that include: site evaluation to ensure wells are located in suitable formations and are constructed to prevent fluid movement; modeling of the site to account for the properties of CO_2; periodic reevaluation of the CO_2 plume; well construction requirements; injection and post-injection monitoring; and financial responsibility requirements.[135]

A related problem under the SDWA is the practice of fracking that is used by the oil and gas industry. The process injects fluids under pressure to fracture rock through hydraulic action to create and enhance cracks through which oil or natural gas can flow to a well.[136] The 2005 Energy Policy Act exempts this practice from federal regulation under the SDWA, except when diesel is used as the fluid. However, EPA on March 18, 2010 announced it was commencing a study to evaluate the potential risks to ground water from fracking that is mandated by its 2010 appropriations law.[137] Companies using hydraulic fracking do not usually disclose to the government the chemicals used in the process.[138] In Pennsylvania on June 2010

[131] *Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration (GS) Wells, Final Rule,* 75 Fed. Reg. 77,229, 77,238 (Dec. 10, 2010) (to be codified at 40 C.F.R. pts. 124, 144, 145, *et seq.*) [hereinafter "UIC Rule"].

[132] *Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration (GS) Wells,* 73 Fed. Reg. 43,491 (proposed July 25, 2008). EPA published a supplemental publication on August 31, 2009, at 74 Fed. Reg. 44,802.

[133] UIC Rule, 75 Fed. Reg. at 77,230.

[134] UIC Rule, 75 Fed. Reg. at 77,231.

[135] UIC Rule, 75 Fed. Reg. at 77,230.

[136] Alan Kosvki, *Advocates Ask EPA to Study Water Pollution From Oil, Gas Drilling, Hydraulic Fracturing,* 41 Env't Rep. (BNA) 499 (Mar. 5, 2010).

[137] *EPA Plans Broad Fracking Risk Study, Boosting Industry's Uncertainty,* XXVII ENVTL. POL'Y ALERT (Inside EPA) 7:35 (Apr. 7, 2010); Alan Kovski, *Science Panel Suggests Risk Assessment To Guide EPA Study on Hydraulic Fracturing,* 41 Env't Rep. (BNA) 847 (Apr. 16, 2010).

[138] Mead Gruver, *Environmentalists: Don't overlook onshore drilling,* SALT LAKE TRIBUNE, July 25, 2010, at B5. Texas-based Range Resources Corp. has published its hydraulic fracturing fluid. The fluid is 94.69% water, 5.17% sand, and 0.14% additives. Hydrochloric acid is used to dissolve cement and minerals; polyacrylamide is used to reduce friction; glutaraldehyde, ethanol, and methanol are used as antimicrobials;

an operator lost control of a fracking operation and 35,000 gallons of drilling fluid was released, along with natural gas. It required sixteen hours to cap the well.[139] Concern over potential fracking accidents led the Wyoming Oil and Gas Conservation Commission to approve rules on June 8, 2010 to require operators to report the chemicals being used to stimulate natural gas production to the state, but the operators may prevent the information from being made public if they can show it is proprietary.[140] Since CO_2 sequestration acts as a hydraulic fluid it potentially will be impacted by any new regulatory developments concerning fracking. Legislation has been introduced that would give EPA authority to regulate fracking under the SDWA.[141] Another bill would modify the Emergency Planning & Community Right-To-Know Act to allow states to require disclosure of chemicals used in fracking operations.[142] But it is unknown whether any legislation or regulation that may emerge will extend to CCS.

§ 3(a)(1). Class VI Permits

The final GS rule creates a new Class VI injection well category under the existing SDWA's UIC program with new minimum federal requirements that protect USDWs from endangerment during underground injection of CO_2 for the purpose of GS. The December 10, 2010 rule includes requirements for permitting, siting, construction, operation, financial responsibility, testing and monitoring, PISC, and site closure of Class VI injection wells.[143] Class VI GS requirements do not apply to Class II ER wells if oil or gas production is occurring, but they will apply after the oil and gas reservoir is depleted. Traditional ER projects are not impacted by the GS December 10, 2010 rule, and will continue operating under Class II permitting requirements.[144] Class VI requirements apply to any CO_2 injection project when there is an increased risk to USDWs, as compared to traditional Class II operations using CO_2.[145] Owners and operators of Class II wells that are injecting CO_2 for the primary purpose of long-term storage into an oil and gas reservoir must apply for and obtain a Class VI permit because EPA foresees an increased risk to USDWs

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ethylene glycol, alcohol, and sodium hydroxide are used to prevent scale deposit in pipes. Nancy J. Moore, *Range Resources Pledges to Disclose Fracturing Additives Used in Shale Drilling,* 41 Env't Rep. (BNA) 1613 (July 16, 2010).

[139] *State Suspends All Gas Well Drilling By EOG Resources Following Well Blowout,* 41 Env't Rep. (BNA) 1324 (June 11, 2010).

[140] Tripp Baltz, *New Regulations Require Operators To Disclose Chemicals Used in Fracturing,* 41 Env't Rep. (BNA) 2095 (Sept. 17, 2010).

[141] *Senate Climate Bill Would Mandate Disclosure Of 'Fracking' Chemicals,* XXVII ENVTL POL'Y ALERT (Inside EPA) 10:38 (May 19, 2010); *Activists Urge Senators To Reject Industry Fracking Measure In Climate Bill,* XXVII ENVTL. POL'Y ALERT (Inside EPA) 7:35 (Apr. 7, 2010). *See also* Alan Kovski, *State Regulators Say Hydraulic Fracturing Produces Debate, but Not Water Problems,* 41 Env't Rep. (BNA) 1101 (May 14, 2010).

[142] *Senate Oil Spill Response Bill Requires Disclosure Of 'Fracking' Chemicals,* XXVII ENVTL POL'Y ALERT (Inside EPA) 16:35 (Aug. 11, 2010).

[143] UIC Rule, 75 Fed. Reg. at 77,246.

[144] UIC Rule, 75 Fed. Reg. at 77,245.

[145] UIC Rule, 75 Fed. Reg. at 77,244.

compared to traditional Class II operations using CO_2 due to the high volumes of CO_2 that will likely be injected.[146] A Class VI permit is issued for the life of the GS project, including the post-injection site care (PISC) period.[147] However owners or operators of Class VI wells must periodically reevaluate the area of review (AoR) where operations are taking place and prepare and implement a series of plans for corrective action, testing and monitoring, injection well plugging, PISC and site closure, and emergency and remedial response. The various mandated plans must be reevaluated and updated by the owner or operator throughout the life of the project.[148] The final rule does not allow for automatic transfer of a Class VI permit to a new owner or operator. EPA requires the Director (either an EPA or approved state UIC official) to review the permit and determine whether any changes are necessary at the time of the permit transfer.[149]

Site Characterization

The final rule requires owners or operators of Class VI wells to perform 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 injections are made into suitable formations.[150] Suitable formations must be geologically free of transmissive faults or fractures and be suitable to receive and confine the injected CO_2 to assure USDW protection. Class VI well owners or operators may also be required by the Director to identify additional confining zones. Minimum siting criteria are set forth at 40 C.F.R. § 146.83.[151]

Owners or operators must submit, with their permit applications, a series of comprehensive site-specific plans: An AoR and corrective action plan, a monitoring and testing plan, an injection well plugging plan, a PISC and site closure plan, and an emergency and remedial response plan. The Director will evaluate all of the plans to ensure that planned activities at the facility are appropriate to the site-specific circumstances and address all risks of endangerment to USDWs.[152]

Area of Review (AoR) and Corrective Action

The final rule at 40 C.F.R. § 146.84 enhances the existing UIC requirements for AoR and corrective action to require computational modeling of the AoR for GS projects to account for the physical and chemical properties of the injected CO_2 based on available site characterization, monitoring, and operational data. Owners or operators must periodically reevaluate the AoR to incorporate monitoring and

[146] UIC Rule, 75 Fed. Reg. at 77,245.
[147] 40 C.F.R. § 144.36 (2010).
[148] UIC Rule, 75 Fed. Reg. at 77,273.
[149] UIC Rule, 75 Fed. Reg. at 77,274.
[150] The material that follows concerning the final GS rule is heavily edited but is taken directly or paraphrased from the final GS rule's preamble.
[151] UIC Rule, 75 Fed. Reg. at 77,247.
[152] UIC Rule, 75 Fed. Reg. at 77,248.

operational data and verify that the CO_2 is moving as predicted within the subsurface.[153]

Owners or operators must develop and implement an AoR and corrective action plan, which, if approved, will be incorporated into the Class VI permit and will be considered permit conditions;[154] failure to follow the plan will result in a permit violation under 42 U.S.C. § 300h-2.[155] Owners or operators must also review the AoR and corrective action plan following an AoR reevaluation and submit an amended plan, or demonstrate to the Director that no amendment to the AoR and corrective action plan is needed.[156] The AoR is defined in the final rule 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 as set forth in § 146.84."[157] The Agency is developing guidance on AoR and corrective action to support AoR delineation (i.e., including regions of the CO_2 plume and pressure front).[158]

EPA requires that the AoR for Class VI wells be determined using sophisticated computational modeling and is developing guidance to support the use of computational models to delineate the AoR.[159] EPA allows any computational model that meets minimum federal requirements and is acceptable to the Director to be used, including proprietary models. EPA requires the AoR delineation be reevaluated periodically over the life of the project in order to incorporate new CO_2 monitoring data into models to ensure protection of USDWs from endangerment. EPA believes that the AoR reevaluation is an efficient use of resources and notes that if the CO_2 plume and pressure front are moving as predicted, the burden of the AoR reevaluation requirement will be minimal. If the observed monitoring data agree with model predictions, an AoR reevaluation may simply consist of a demonstration to the Director that monitoring data validate modeled predictions.[160]

Owners or operators of Class VI wells must identify and evaluate all artificial penetrations within the AoR. Based on this review, owners or operators, in consultation with the Director, would identify the wells that need corrective action to prevent the movement of CO_2 or other fluids into or between USDWs. Owners or operators would perform corrective action to address deficiencies in any wells (regardless of ownership) that are identified as potential conduits for fluid

[153] UIC Rule, 75 Fed. Reg. at 77,248.
[154] UIC Rule, 75 Fed. Reg. at 77,248.
[155] 42 U.S.C. § 1423.
[156] SDWA § 300j(e)(4), 42 U.S.C. § 146.84(e)(4).
[157] UIC Rule, 75 Fed. Reg. at 77,231, 77,249.
[158] UIC Rule, 75 Fed. Reg. at 77,249.
[159] *Id.*
[160] *Id.*

movement into USDWs.[161] EPA allows corrective action to be phased to spread costs over the life of the project.[162]

Injection Well Construction

The final rule imposes requirements for the design and construction of Class VI wells using materials that can withstand contact with CO_2 over the life of the GS project in order to prevent movement of fluids into USDWs.[163] Proper construction of injection wells provides multiple layers of protection to ensure the prevention of fluid movement into USDWs. The final rule is based on existing construction requirements for surface casing, long-string casing, and tubing and packer for Class I hazardous waste injection wells, with modifications to address the unique physical characteristics of CO_2, including its buoyancy relative to other fluids in the subsurface and the potential presence of impurities in captured CO_2.[164]

Class VI Injection Depth Waivers

The final rule includes requirements that allow owners or operators to seek a waiver from the Class VI injection depth requirements for GS to allow injection into non-USDW formations while ensuring that USDWs above and below the injection zone are protected from endangerment.[165] The final injection depth waiver requirements apply to all non-USDWs including: (1) Formations that have salinities greater than 10,000 mg/l total dissolved solids (TDS) and (2) all eligible previously exempted aquifers situated above and/or between USDWs. EPA believes that collection and assessment of site- and project-specific information is integral to the waiver process. It is developing guidance to support owners or operators in assessing a GS project site and applying for a waiver of the Class VI injection depth requirements and to assist Directors in evaluating waiver applications.[166]

Adoption of the waiver process will remain at the discretion of individual UIC programs, since States may choose to develop requirements that are more stringent than the minimum federal requirements provided in today's rule. States, Territories, and Tribes seeking primacy to regulate Class VI wells are not required to provide for injection depth waivers in their UIC regulations and may choose not to make this process available to owners or operators of Class VI wells under their jurisdiction. EPA believes a decision about whether a waiver program is appropriate should be made by the State, Tribe, or Territory. No waivers may be issued by a State prior to the establishment of a Class VI UIC program in the State. This is designed to ensure that States determine whether a waiver process will be allowed as part of their GS program. To facilitate experimental injection for GS and to increase understanding

[161] UIC Rule, 75 Fed. Reg. at 77,250.
[162] 40 C.F.R. § 146.84(d).
[163] UIC Rule, 75 Fed. Reg. at 77, 250; 40 C.F.R. § 146.86.
[164] UIC Rule, 75 Fed. Reg. at 77,250.
[165] UIC Rule, 75 Fed. Reg. at 77,251; 40 C.F.R. § 146.95.
[166] UIC Rule, 75 Fed. Reg. at 77,252.

of injection into basalts, shales, and other formation types, EPA is preparing additional guidance for owners or operators and Directors regarding the use of Class V experimental technology.[167]

Injection Well Operation

The final rule contains requirements for the operation of Class VI wells, including 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. The requirements for operation of Class VI injection wells are based on the existing requirements for Class I wells, with enhancements to account for the unique conditions that will occur during GS including buoyancy, corrosivity, and higher sustained pressures over a longer period of operation. EPA proposed that owners or operators limit injection pressure such that pressure in the injection zone does not exceed 90 percent of the fracture pressure of the injection zone, and that injection may not initiate new fractures or propagate existing fractures. The calculated fracture pressure, which determines the injection pressure limit, is based on site-specific geologic and geomechanical data collected during the site characterization process.[168]

Testing and Monitoring

The final rule at 40 C.F.R. § 146.90 requires owners or operators of Class VI wells to develop and implement a comprehensive testing and monitoring plan for their projects that includes injectate monitoring, corrosion monitoring of the well's tubular, mechanical, and cement components, pressure fall-off testing, ground water quality monitoring, CO_2 plume and pressure front tracking, and, at the Director's discretion, surface air and soil gas monitoring. The rule also requires a mechanical integrity test (MIT) to verify proper well construction, operation, and maintenance.[169] Monitoring data can be used to verify that the injectate is safely confined in the target formation, minimize costs, maintain the efficiency of the storage operation, confirm that injection zone pressure changes follow predictions, and serve as inputs for AoR modeling. In conjunction with careful site selection and AoR delineation, monitoring is critical to the successful operation, PISC, and site closure of a GS project.[170]

Monitoring requirements are based on existing UIC regulations, tailored to address the needs and challenges posed by GS projects. The testing and monitoring requirements for Class VI wells at 40 C.F.R. § 146.90 incorporate elements of pre-existing UIC requirements for monitoring and testing, tailored and augmented as appropriate for GS projects. The Agency is developing guidance to support testing

[167] UIC Rule, 75 Fed. Reg. at 77,256.
[168] UIC Rule, 75 Fed. Reg, at 77,257; 40 C.F.R. § 146.88.
[169] UIC Rule, 75 Fed. Reg. at 77,259.
[170] *Id.*

and monitoring at GS sites.[171] The final rule requires owners or operators of Class VI wells to submit monitoring plans with their permit application. The testing and monitoring plan is to be incorporated into the Class VI permit. Owners or operators must also periodically review the testing and monitoring plan to incorporate operational and monitoring data and the most recent AoR reevaluation (§ 146.90(j)). This review must take place within one year of an AoR reevaluation, following significant changes to the facility, or when required by the Director. The Agency is developing guidance that describes the contents of the project plans required in the GS rule, including the testing and monitoring plan.[172]

The final rule requires owners or operators to characterize their CO_2 stream as part of their UIC permit application and throughout the operational life of the injection facility. The details of the sampling process and frequency must be described in the Director-approved, site/project-specific testing and monitoring plan. Injectate analysis provides information on the chemical composition and physical characteristics of the injectate. Analysis of the CO_2 stream for GS projects will provide information about any impurities that may be present and whether such impurities might alter the corrosivity of the injectate. Such information is necessary to inform well construction and the project-specific testing and monitoring plan, and enable the owner or operator to optimize well operating parameters while ensuring compliance with the Class VI permit.[173]

The UIC program Director has authority under the SDWA to address potential compliance issues resulting from injection violations in the unlikely event that an emergency or remedial response is necessary. Although EPA anticipates that the need for emergency or remedial actions at GS sites will be rare, today's rule requires that emergency and remedial response plans be developed and updated to address such events and that owners or operators demonstrate that financial resources are set aside to implement the plans if necessary.[174]

Injection well MIT is a critical component of the UIC program's requirements designed to ensure USDW protection from endangerment. Testing and monitoring the integrity of an injection well at an appropriate frequency throughout the injection operation, in conjunction with corrosion monitoring of well materials, can verify that the injection system is operating as intended or provide notice that there may be a loss of containment that may lead to endangerment of USDWs.[175] The final rule at 40 C.F.R. § 146.89 retains the requirements for continuous monitoring to demonstrate internal mechanical integrity. This is driven by concerns that the potential corrosivity of CO_2 in the presence of water and the anticipated high pressures and volumes of injectate could compromise the integrity of the well. The

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[171] *Id.*
[172] *Id.*
[173] UIC Rule, 75 Fed. Reg. at 77,260.
[174] *Id.*; 40 C.F.R. §§ 146.94 & .85.
[175] UIC Rule, 75 Fed. Reg. at 77,261.

technologies used for continuous monitoring are currently available and widely used.[176]

External well MIT is demonstrated by establishing the absence of significant fluid movement along the outside of the casing, generally between the cement and the well structure, and between the cement and the well-bore. Failure of an external MIT can indicate improper cementing or degradation of the cement that was emplaced to fill and seal the annular space between the outside of the casing and the well-bore. This type of failure can lead to movement of injected fluids out of intended injection zones and toward USDWs. Because GS is a new technology and there are a number of unknowns associated with the long-term effects of injecting large volumes of CO_2, the rule requires owners or operators of CO_2 injection wells to demonstrate external mechanical integrity at least once annually during injection operations. This increase in required testing frequency relative to other injection well classes ensures the protection of USDWs from endangerment given the potential corrosive effects of CO_2 (in the presence of water) on well components (steel casing and cement) and the buoyant nature of supercritical CO_2 relative to formation brines, which could enable it to migrate up a compromised wellbore.[177]

Existing UIC Class I deep well operating requirements allow the Director discretion to require corrosion monitoring and control where corrosive fluids are injected. Corrosion monitoring can provide early warning of well material corrosion that could compromise the well's mechanical integrity. Given the potential for corrosion of well components if they are in contact with water saturated with CO_2 or CO_2 in the presence of water, corrosion monitoring is included as a routine part of Class VI well testing. EPA requires quarterly corrosion monitoring in the final rule at 40 C.F.R.§ 146.90(c).[178]

Ground water and geochemical monitoring ensure protection of USDWs from endangerment, preserve water quality, and allow for timely detection of any leakage of CO_2 or displaced formation fluids out of the target formation and/or through the confining layer. Periodically analyzing ground water quality above the confining layer can reveal geochemical changes that result from leaching or mobilization of heavy metals and organic compounds, or fluid displacement.[179] The final rule, at 40 C.F.R. § 146.90(d), retains the requirement for direct ground water quality monitoring as specified in the site-specific monitoring plan. The number, placement, and depth of monitoring wells will be site-specific and will be based on information collected during baseline site characterization.[180]

Pressure fall-off tests are designed to determine if reservoir pressures are

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[176] *Id.*
[177] *Id.*
[178] *Id.*
[179] *Id.*
[180] UIC Rule, 75 Fed. Reg. at 77,262.

tracking predicted pressures and modeling inputs. The results of pressure fall-off tests will confirm site characterization information, inform AoR reevaluations, and verify that projects are operating properly and the injection zone is responding as predicted. EPA proposed that owners or operators perform pressure fall-off testing at least once every five years. The final rule, at 40 C.F.R. § 146.90(f), retains the requirement for testing at least once every five years.

Monitoring the movement of the CO_2 and the pressure front are necessary to identify potential risks to USDWs posed by injection activities, verify predictions of plume movement, provide inputs for modeling, identify needed corrective actions, and target other monitoring activities. The final rule at 40 C.F.R. § 146.90 requires Class VI well owners or operators to perform monitoring to track the extent of the CO_2 plume and pressure front. The owner or operator must use direct methods to monitor for pressure changes in the injection zone. Indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole CO_2 detection tools) are required unless the Director determines, based on site-specific geology that such methods are not appropriate.[181]

Additionally, 40 C.F.R. § 146.90(g)(2) requires owners or operators to track the position of the CO_2 plume using indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole CO_2 detection tools), unless the Director determines based on site-specific geology, that such methods are not appropriate. EPA is affording Director's discretion regarding the use of geophysical techniques at some sites because the Agency recognizes that geophysical methods are not appropriate in all geologic settings. This determination will be made by the Director based on the site-specific geologic information submitted by the owner or operator with their permit application. EPA requires indirect plume monitoring unless the Director determines it is not appropriate.[182]

Surface Air/Soil Gas Monitoring

Surface air and soil gas monitoring can be used to monitor the flux of CO_2 out of the subsurface, with elevation of CO_2 levels above background levels indicating potential leakage and USDW endangerment. While deep subsurface well monitoring forms the primary basis for detecting threats to USDWs, knowledge of leaks to shallow USDWs is of critical importance because these USDWs are more likely to serve public water supplies than deeper formations. If leakage to a USDW should occur, near-surface and surface monitoring may assist owners or operators in identifying the general location of the leak and what USDWs may have been impacted by the leak, and initiating targeted emergency and remedial response

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[181] The final rule requires owners or operators to characterize their CO_2 stream as part of their UIC permit application and throughout the operational life of the injection facility. The details of the sampling process and frequency must be described in the Director-approved, site/project-specific testing and monitoring plan. UIC Rule, 75 Fed. Reg. at 77,260.

[182] UIC Rule, 75 Fed. Reg. at 77,262.

actions. The decision to use surface monitoring and the selection of monitoring methods will be site-specific and must be based on potential risks to USDWs within the AoR. The final rule at 40 C.F.R. § 146.90(h) allows surface air and soil gas monitoring at the discretion of the Director as a means of identifying leaks that may pose a risk to USDWs.[183]

EPA concurrent rulemaking concerning GS reporting requirements under the GHG Reporting Program (subpart RR) builds on UIC requirements with the additional goals of verifying the amount of CO_2 sequestered and collecting data on any CO_2 surface emissions.[184] If a Director requires surface air/soil gas monitoring pursuant to requirements at 40 C.F.R. § 146.90(h), and an owner or operator demonstrates that monitoring employed under 40 C.F.R. §§ 98.440 to 98.449 of subpart RR meets the requirements at 40 C.F.R. § 146.90(h)(3), the Director must approve the use of monitoring employed under subpart RR.

EPA recognizes that monitoring and testing technologies used at GS sites will vary and be project-specific, influenced by both geologic conditions and the project's characteristics. At certain sites additional monitoring may be needed. The final rule, at 40 C.F.R. § 146.90(k), requires owners or operators to submit a quality assurance and surveillance plan (QASP) for all testing and monitoring requirements.[185]

Class VI well owners or operators are required to develop and maintain an emergency and remedial response plan that describes actions to be taken to address events that may cause endangerment to a USDW during the construction, operation, and PISC periods of a GS project. Owners or operators must also periodically update the emergency and remedial response plan to incorporate changes to the AoR or other significant changes to the project.[186] The final rule at § 146.94(b) requires that, if an owner or operator obtains evidence of endangerment to a USDW, he or she must: (1) immediately cease injection; (2) take all steps reasonably necessary to identify and characterize any release; (3) notify the Director within 24 hours; and, (4) implement the approved emergency and remedial response plan.[187]

Recordkeeping and Reporting

The final rule at 40 C.F.R. § 146.91 requires owners or operators of Class VI wells to submit the results of required periodic testing and monitoring associated with the GS project and requires that all required reports, submittals, and notifications under subpart H be submitted to EPA in an electronic format. This requirement applies to owners or operators in Class VI primacy States and in States where EPA implements the Class VI program, pursuant to 40 C.F.R. § 147.1. All

[183] UIC Rule, 75 Fed. Reg. at 77,263.
[184] *See infra* § 3(a)(2).
[185] UIC Rule, 75 Fed. Reg. at 77,263-64.
[186] UIC Rule, 75 Fed. Reg. at 77,272 (codified at 40 C.F.R. § 146.94).
[187] UIC Rule, 75 Fed. Reg. at 77,273.

Directors will have access to the data through the EPA electronic data system.

The rule identifies the technical information and reports that Class VI owners or operators must submit to the Director to obtain a Class VI permit to construct, operate, monitor, and close a Class VI well. The information submitted as a demonstration to the Director must be in the appropriate format and level of detail necessary to support permitting and project-specific decisions by the Director to ensure USDW protection. The final decision regarding the appropriateness and acceptability of all owner or operator submissions rests with the Director. Owners or operators must submit, pursuant to the requirements at 40 C.F.R. § 146.91(e), information enumerated at 40 C.F.R. § 146.82 to the Director to support Class VI permit applications. This information includes site characterization information on the stratigraphy, geologic structure, and hydrogeologic properties of the site; a demonstration that the applicant has met financial responsibility requirements; proposed construction, operating, and testing procedures; and AoR/corrective action, testing and monitoring, well plugging, PISC and site closure, and emergency and remedial response plans.[188]

Owners or operators must submit project monitoring and operational data at varying intervals, including semi-annually and prior to or following specific events (e.g., 30-day notifications and 24-hour emergency notifications) as specified at 40 C.F.R. §146.91. Owners or operators also must report the results of mechanical integrity tests and any other injection well testing required by the Director and provide written notification 30 days prior to any planned well workover, stimulation, or test of the injection well. Owners or operators are to electronically submit AoR reevaluation information and all plan amendments, pursuant to 40 C.F.R. § 146.84, at a minimum of every five years. The final rule does not include a requirement for an annual report.[189]

Owners or operators must retain most operational monitoring data as required under 40 C.F.R. § 146.91 for ten years after the data are collected. The final rule clarifies the recordkeeping requirements for Class VI well owners or operators. These include the requirements at 40 C.F.R. § 144.51(j) and the Class VI-specific recordkeeping requirements at 40 C.F.R. § 146.91(f). Class VI well owners or operators must retain data collected to support permit applications and data on the CO_2 stream until ten years after site closure. Owners or operators must retain monitoring data collected under the testing and monitoring requirements for ten years after it is collected. The rule allows the Director authority to require the owner or operator to retain specific operational monitoring data for a longer duration of time. Well plugging reports, PISC data, and site closure reports must be kept for ten years after site closure. [190]

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[188] UIC Rule, 75 Fed. Reg. at 77,264, 77,265.
[189] UIC Rule, 75 Fed. Reg. at 77,265.
[190] UIC Rule, 75 Fed. Reg. at 77,265.

Well Plugging, Post-Injection Site Care (PISC), and Site Closure

Owners or operators of Class VI wells must plug injection and monitoring wells in a manner specified in 40 C.F.R. § 146.82 to protect USDWs. The final rule, at 40 C.F.R. § 146.93, also contains tailored requirements for extended, comprehensive post-injection monitoring and site care of GS projects following cessation of injection until it can be demonstrated that movement of the CO_2 plume and pressure front no longer pose a risk of endangerment to USDWs. The owners or operators must prepare and comply with a Director-approved injection well plugging plan submitted with their permit application. The approved injection well plugging plan will be incorporated into the Class VI permit. Owners or operators must submit a notice of intent to plug at least sixty days prior to plugging the well. Finally, owners or operators must submit, to the Director, a plugging report within sixty days after plugging. EPA is developing guidance on injection well plugging, PISC, and site closure that addresses performing well plugging activities.[191]

PISC is required during the period after CO_2 injection ceases and prior to site closure. During that period, pursuant to 40 C.F.R. § 146.93, the owner or operator must continue monitoring to ensure USDW protection from endangerment. The requirement to maintain and implement the approved PISC and site closure plan is directly enforceable regardless of whether the requirement is a condition of the Class VI permit. The PISC and site closure plan will serve to clarify PISC requirements and procedures prior to commencement of a project.[192]

Upon cessation of injection, owners or operators of Class VI wells either submit an amended PISC and site closure plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the plan is needed. The Agency is developing guidance that describes the content of the project plans required in the GS rule, including the PISC and site closure plan. EPA retains the proposed default fifty-year PISC timeframe but affords flexibility regarding the duration of the PISC timeframe by: (1) allowing the Director discretion to shorten or lengthen the PISC timeframe during the PISC period based on site-specific data, pursuant to requirements at 40 C.F.R. § 146.93(b); and, (2) affording the Director discretion to approve a Class VI well owner or operator to demonstrate, based on substantial data during the permitting process, that an alternative PISC timeframe is appropriate if it ensures non-endangerment of USDWs pursuant to requirements at 40 C.F.R. § 146.93(c).[193]

The Director may lengthen the PISC timeframe if, after fifty years, USDWs still may become endangered. EPA believes that a default post-injection site care timeframe of fifty years, with flexibility to adjust the timeframe during the permitting process where substantial data exists to demonstrate that an alternative

[191] UIC Rule, 75 Fed. Reg. at 77,266.
[192] UIC Rule, 75 Fed. Reg. at 77,266.
[193] *Id.*

timeframe would be protective of USDWs, or based on data collected during the PISC period, is appropriate to address the range of sites where GS is anticipated to occur, and to accommodate site-specific circumstances and various geologic conditions while ensuring USDW protection. The Agency is developing guidance on injection well plugging, PISC, and site closure.[194]

Following a determination under 40 C.F.R. § 146.93 that the site no longer poses a risk of endangerment to USDWs, the Director may approve site closure and the owner or operator would close site operations. EPA proposed site closure activities similar to those for other well classes. These include plugging all monitoring wells; submitting a site closure report; and recording a notation on the deed to the facility property or other documents that the land has been used to sequester CO_2. Site closure would proceed according to the approved PISC and site closure plan as specified at 40 C.F.R. § 146.93(d) through (h).[195]

A Class VI permit does not necessarily protect operators from liability based on the Clean Air Act (CAA), the Resource Conservation & Recovery Act (RCRA)[196] or the Comprehensive Environmental Response, Compensation, and Liability (CERCLA or Superfund).[197] EPA indicates that the concentration of impurities in the waste is expected to be low, but in the SDWA the Agency leaves it to the permit holder to determine whether CO_2 injection is hazardous under RCRA or CERCLA.[198]

Ultimately, the SDWA is too limited in its scope to resolve the legal issues that will arise if a large-scale CCS program is to develop. A more comprehensive statute is needed that deals with the long-term liability issues. Many in the coal-burning electric power industry fear that a failure to shield CCS projects from RCRA/CERCLA liability will prevent their commercialization.[199] In addition, operators have potential liability based on tort law.[200] EPA's UIC rule under SDWA affects state regulation, but the role of the states cannot easily be preempted because legal issues concerning sequestration will involve property, tort, and contract law that are controlled by state law.[201]

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[194] UIC Rule, 75 Fed. Reg. at 77,268.
[195] *Id.*
[196] 42 U.S.C. §§ 6901-6992k (West 2010).
[197] 42 U.S.C. §§ 9601-9675.
[198] *See infra* § 3(c).
[199] *Western Businesses Warn EPA Liability Rules May Sink CCS Projects,* XXVI ENVTL POL'Y ALERT 22:26 (Nov. 5, 2009).
[200] *See generally* Alexandra B. Klass & Elizabeth J. Wilson, *Climate Change and Carbon Sequestration: Assessing a Liability Regime for Long-Term Storage of Carbon Dioxide,* 58 EMORY L. J. 103 (2008); Peter S. Glaser, *et al., Global Warming Solutions: Regulatory Challenges and Common Law Liabilities Associated With the Geological Sequestration of Carbon Dioxide,* 6 GEORGETOWN J. L. & PUB. POL'Y 429 (2008).
[201] Elizabeth J. Wilson & Mark A. de Figueiredo, *Geologic Carbon Dioxide Sequestration: An Analysis of Subsurface Property Law,* 36 ENVTL LAW REP. (ELI) 10114 (Feb. 2006); *see also* Reitze, *State CCS*, *supra* note 89.

§ 3(a)(2). Monitoring and Reporting

EPA also seeks to impose monitoring and reporting requirements on sequestration operations based on its authority under CAA §§114 and 208.[202] The Agency promulgated a final regulation to implement a mandatory GHG emissions reporting program on October 30, 2009.[203] The regulation became effective on January 1, 2010, with the first reports due on March 31, 2011.[204] It applies to fossil fuel suppliers, industrial gas suppliers, and direct GHG emitters if they emit 25,000 metric tons of GHGs or more a year expressed as carbon dioxide equivalent (CO_{2e}).[205] Some facilities in identified categories must report even if emissions are below 25,000 tons of CO_{2e}. Facilities within listed categories include electric power plants subject to the Acid Rain Program, including those owned by the federal and municipal governments and those located in Indian Country.[206]

On March 23, 2010, EPA proposed three rules to require GHG reporting by oil and natural gas well operations, carbon sequestration facilities, and facilities that produce or import or use fluorinated gases, such as hydrofluorocarbons (HFCs).[207] The sequestration reporting requirements apply to CO_2 that is sequestered underground and require reporting of the amount received, the amount injected, and the source of the CO_2, if known. It requires the development and implementation of an EPA approved site-specific monitoring, reporting, and verification (MRV) plan that is to include a strategy for detecting and quantifying CO_2 leakage. EPA estimates monitoring and reporting will cost about $300,000 a year for each site.[208] On December 1, 2010, EPA promulgated a final rule mandating reporting of GHGs from carbon injection and geologic sequestration.[209]

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[202] 42 U.S.C. §§ 7414 & 7542 (West 2010).

[203] *Mandatory Reporting of Greenhouse Gases*, 74 Fed. Reg. 56,260 (Oct. 30, 2009). The reporting program was expanded with additional requirements in 2010 (75 Fed. Reg. 39,736 (July 12, 2010)) [hereinafter GHG Reporting].

[204] *Id.*

[205] Carbon dioxide equivalent: The amount of carbon dioxide by weight emitted into the atmosphere that would produce the same estimated radiative forcing as a given weight of another radiatively active gas. Carbon dioxide equivalents are computed by multiplying the weight of the gas being measured (for example, methane) by its estimated global warming potential (which is 21 for methane). "Carbon equivalent units" are defined as carbon dioxide equivalents multiplied by the carbon content of carbon dioxide (i.e., 12/44). Energy Information Administration, Glossary, Carbon Dioxide Equivalent, http://www.eia.doe.gov/glossary/glossary_c.htm (last visited Dec. 3, 2010).

[206] GHG Reporting, 74 Fed. Reg. at 56,264.

[207] Steven D. Cook, *EPA Proposes Greenhouse Gas Reporting For Oil and Gas Wells, Carbon Storage, HFCs,* 41 Env't Rep. (BNA) 659 (Mar. 26, 2010).

[208] Steven Cook, *EPA Proposes Greenhouse Gas Reporting For Oil and Gas Wells, Carbon Storage, HFCs,* 41 Env't Rep. (BNA) 659 (Mar. 26, 2010).

[209] *Mandatory Reporting of Greenhouse Gases: Injection and Geologic Sequestration of Carbon Dioxide,* 75 Fed. Reg. 75,059 (Dec. 1, 2010) [hereinafter GHG GS], (to be codified at 40 C.F.R. pt. 98, subpt. RR). *See also* www.epa.gov/climatechange/emissions/ghgrulemaking.html (last visited Dec. 2, 2010). The rule is based on EPA's authority provided in CAA § 114.

The reporting rule, at 40 C.F.R. Part 98, Subpart RR, requires GS facilities to collect data on the amount injected in a quarter and annually. All other facilities that inject CO_2 underground are subject to Part 98, Subpart UU.[210] Research and development projects are exempt from the reporting requirements of 40 C.F.R. Part 98, Subpart RR, if they meet eligibility requirements. Most of the existing CCS projects would appear to be R & D projects that are exempt from the need to comply with Subpart RR. However, they are not exempted from other potentially applicable Part 98 reporting requirements, including Subpart UU requirements.[211]

Owners or operators subject to the December 10, 2010, GS rule are required to report under subpart RR. Subpart RR establishes reporting requirements for facilities that inject a CO_2 stream for long-term containment into a subsurface geologic formation, including sub-seabed offshore formations.[212] These facilities are required to develop and implement a site-specific MRV plan which, once approved by EPA (in a process separate from the UIC permitting process), would be used to verify the amount of CO_2 sequestered and to quantify emissions in the event that injected CO_2 leaks to the surface. EPA designed the reporting requirements under subpart RR with consideration of the requirements for Class VI well owners or operators in subpart H of part 146 of the UIC GS rule. Subpart RR builds on the Class VI requirements outlined in the UIC GS rule to verify the amount of CO_2 sequestered and to collect data on any CO_2 surface emissions from GS facilities as identified under subpart RR of part 98.[213] This data will assist EPA when making policy decisions under CAA sections 111 and 112 related to the use of CCS for mitigating GHG emissions. In combination with data from other subparts of the GHG Reporting Program, data from subpart UU and subpart RR will allow EPA to track the flow of CO_2 across the CCS system. EPA will be able to reconcile subpart RR data on CO_2 received with CO_2 supply data in order to understand the quantity of CO_2 supply that is geologically sequestered.[214]

EPA realizes there are similar data elements that must be reported pursuant to requirements in the UIC GS rules and those required to be reported under subpart RR. Owners or operators subject to both regulations must report the amount (flow rate) of injected CO_2. The UIC Class VI and subpart RR rules differ not only in purpose, but in the specific requirements for the measurement unit and collection/reporting frequency. The UIC Class VI rule requires that owners or operators report information on the CO_2 stream to ensure appropriate well siting, construction, operation, monitoring, post-injection site care, site closure, and financial responsibility to ensure protection of USDWs. Under subpart RR, owners or operators must report the amount (flow rate) of injected CO_2 for the mass balance equation that will be used to quantify the amount of CO_2 sequestered by a

[210] UIC Rule, 75 Fed. Reg. at 77,235.
[211] GHG GS, 75 Fed. Reg. at 75,064-65.
[212] *Id.*
[213] UIC Rule, 75 Fed. Reg. at 77,236.
[214] UIC Rule, 75 Fed. Reg. at 77,235.

facility. However, compliance with the reporting requirements of Subpart RR will meet most of the reporting requirements of UIC Class VI, as shown in Table II-1 of the rule. EPA is working to better integrate data management between the UIC and GHG Reporting Programs to ensure that data needs are harmonized and the burden to regulated entities is minimized.[215]

§ 3(a)(3). Administration of the UIC Program

EPA administers the UIC program in ten states.[216] The UIC program regulates underground injection activities including EOR, but it does not encompass the underground storage of natural gas.[217] The Energy Independence and Security Act of 2007 gave EPA the explicit authority under the SDWA to regulate injection and geologic sequestration of CO_2.[218] Governors from oil and gas producing states did not want federal regulation of CO_2 injection because they do not want interference with the use of CO_2 to force natural gas and petroleum to the surface that is regulated by the oil and gas producing states. These injection operations are small compared to what would be required to sequester CO_2 emissions from fossil-fueled electric power plants.[219]

EPA administers the SDWA's UIC program on Indian lands based on 18 U.S.C. § 1151, which defines Indian country to include reservations, Indian allotments, and dependent Indian communities. The first two categories have been defined with reasonable precision, but the third category is somewhat ambiguous and has been applied to include lands owned by non-Indians.[220] Sequestration activities in the West could easily involve lands that are subject to Indian law. Determining whether land in Indian country is subject to state or EPA jurisdiction requires using the tests established by judicial decisions.[221] The Tenth Circuit revisited this issue when it ruled on April 17, 2009, that a non-Indian mining corporation that intended to operate a uranium mine in New Mexico was subject to regulation by EPA because the land was within a dependent Indiana community.[222] No one lived on the land; taxes were paid to McKinley County, New Mexico; all government services were provided by New Mexico. However, the land was six miles from a small Navajo town, which was sufficient for EPA to rule the land was subject to tribal jurisdiction, and the court upheld the decision. However, the Tenth Circuit, sitting en banc rejected EPA's subjective community reference test, holding it was superseded by the U.S. Supreme Court's holding in *Venetie.* The proper test to determine whether lands are

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[215] UIC Rule, 75 Fed. Reg. at 77,235.
[216] GAO, *supra* note 45, at 15.
[217] 40 C.F.R. §§140-146.
[218] Pub. L. No. 110-140 (Dec. 19, 2007).
[219] *Oil, Natural Gas Producing States Offer Strategy For Carbon Capture,* XVI CLEAN AIR REP. (Inside EPA) 6:27 (Mar. 24, 2005).
[220] *See e.g.* U.S. v. Mazurie, 419 U.S. 544, 546-47 (1975).
[221] *See e.g.* Alaska v. Native Village of Venetie Tribal Government, 522 U.S. 520 (1998).
[222] Hydro Resources, Inc. v. EPA, 562 F.3d 1249, *vacated by* 608 F.3d 1131 (10th Cir. 2010).

part of Indian country and thus subject to tribal jurisdiction focuses only on the lands in question (rather than the surrounding area) and requires the lands to be 1) set aside by Congress and 2) superintended by the federal government.[223]

While the new test seems clearer and more straightforward than the community of reference test, the Tenth Circuit Court muddied the waters by suggesting EPA may want to use its "considerable discretion" to employ some other test to determine jurisdiction over SDWA issues, noting, “While § 1151 does its job of assigning prosecutorial authority over particular tracts of land tolerably well, it is perhaps unsurprising that it may prove less satisfactory when it comes to allocating regulatory authority over aquifers running beneath those lands. . . . Someday, EPA may seek to avoid these difficulties by unhitching its UIC permitting authority from § 1151.”[224]

Thirty-three states and three territories have been given “primacy”, or primary enforcement authority, and seven states have partial authority to administer the UIC program based on the program found in the SDWA § 1421(b).[225] That section mandates that EPA develop minimum federal requirements for State UIC primary enforcement responsibility, or primacy, to protect underground drinking water supplies. To administer the UIC program, States must apply to EPA for primacy approval and demonstrate: (1) State jurisdiction over underground injection projects; (2) that their State regulations are at least as stringent as those promulgated by EPA (e.g., permitting, inspection, operation, monitoring, and recordkeeping requirements); and (3) that the State has the necessary administrative, civil, and criminal enforcement penalty remedies pursuant to 40 C.F.R. § 145.13.[226] EPA’s Administrator must review and approve or disapprove or disapprove part of a State's primacy application. This determination is based on EPA's mandate under the SDWA as implemented by UIC regulations established in 40 C.F.R. Part 144 through 146, and must be made by a rulemaking.[227]

Under SDWA § 1422, States must demonstrate that their proposed UIC program meets the statutory requirements under section 1421 and that their program contains requirements that are at least as stringent as the minimum federal requirements provided for in the UIC regulations to ensure protection of USDWs. In the December 10, 2010 final UIC rule, and in accordance with the SDWA section 1422, all Class VI State programs must be at least as stringent as the minimum federal requirements.[228]

EPA’s practice has been to not accept UIC primacy applications from States for individual well classes. If a State wanted primacy it would need to accept it for all

[223] 608 F.3d at 1166.
[224] *Id.*
[225] 42 U.S.C. § 300h(b) (West 2010). A complete list of the primacy agencies in each State is available at http://www.epa.gov/safewater/uic/primacy.html (last visited Dec. 21, 2010).
[226] UIC Rule, 75 Fed. Reg. at 77,240.
[227] *Id.*
[228] UIC Rule, 75 Fed. Reg. at 77,241.

well classes. However, the Agency will allow independent primacy for Class VI wells under § 145.1(i) of the final rule. EPA will not consider applications for independent primacy for any other injection well class under SDWA section 1422 other than Class VI, nor will the Agency accept the return of portions of existing 1422 programs. EPA will continue to process primacy applications for Class II injection wells under the authority of section 1425 of the SDWA. The Agency plans to provide guidance to States applying for Class VI primacy under section 1422 of SDWA and to assist UIC Directors evaluating permit applications.[229]

The final UIC rule establishes a federal Class VI primacy program in States that choose not to seek primacy for the Class VI portion of the UIC program within the approval timeframe established under section 1422(b)(1)(B) of the SDWA.[230] States will have 270 days following final promulgation of the GS rule to submit a complete primacy application that meets the requirements of §§ 145.22 or 145.32. States must follow the requirements found in 40 C.F.R. § 145.23(f). If a State does not submit a complete application during the 270-day period, or EPA has not approved a State's Class VI program submission, then EPA will establish a federal UIC Class VI program in that State after the application period closes.[231] States may not issue Class VI UIC permits until their Class VI UIC programs are approved. Until a State has an approved Class VI program, EPA will establish and implement a Class VI program, and the appropriate EPA Region will issue Class VI permits.

The December 10, 2010 rule requires the Director of Class VI programs approved before December 10, 2011, to notify owners or operators of any Class I wells previously permitted for the purpose of geologic sequestration or Class V experimental technology wells no longer being used for experimental purposes that will continue injection of CO_2 for the purpose of GS that they must apply for a Class VI permit pursuant to requirements at § 146.81(c) within one year of December 10, 2011.[232]

§ 3(a)(4). Fiscal Responsibility

EPA requires owners or operators to demonstrate and maintain financial responsibility, as specified in regulations at 40 C.F.R. § 146.85, for performing corrective action on wells in the AoR, injection well plugging, PISC and site closure, and emergency and remedial response. Financial assurance is typically demonstrated through: (1) Third party instruments, including surety bond, financial guarantee bond or performance bond, letters of credit (the above third party instruments must also establish a standby trust fund), and an irrevocable trust fund; and (2) self-insurance instruments, including the corporate financial test and the

[229] UIC Rule, 75 Fed. Reg. at 77,242.
[230] 40 C.F.R. § 145.21(h).
[231] UIC Rule, 75 Fed. Reg. at 77,242.
[232] 40 C.F.R. § 145.23(f)(4).

corporate guarantee.[233] EPA reevaluated the current minimum Tangible Net Worth (TNW) requirement of $10 million used in the Class I regulations and will recommend a TNW threshold for Class VI wells in guidance to be issued in 2011. The financial responsibility guidance will also include a recommended cost estimation methodology to assist owners or operators of Class VI wells and will provide examples of cost considerations and activities that may need to be performed to satisfy the requirements of today's rule.[234]

Once an owner or operator has met all regulatory requirements under part 146 for Class VI wells and the Director has approved site closure pursuant to requirements at § 146.93, the owner or operator will generally no longer be subject to enforcement under section 1423 of SDWA for noncompliance with UIC regulatory requirements. However, an owner or operator may be held liable for regulatory noncompliance under certain circumstances even after site closure is approved under § 146.93, under section 1423 of the SDWA for violating § 144.12, such as where the owner or operator provided erroneous data to support approval of site closure.[235] An owner or operator, however, may always be subject to an order the Administrator deems necessary to protect the health of persons under section 1431 of the SDWA after site closure if there is fluid migration that causes or threatens imminent and substantial endangerment to a USDW. The order may include commencing a civil action for appropriate relief. If the owner or operator fails to comply with the order, they may be subject to a civil penalty for each day in which such violation occurs or failure to comply continues. EPA does not have authority to transfer liability from one entity (i.e., owner or operator) to another.[236]

§ 3(b). Clean Air Act

New pulverized coal plants must meet the new source performance standards (NSPS) for coal-fired power plants.[237] These requirements are based on 1979 regulations.[238] NSPS also apply to modifications that increase the amount of air pollution emitted or that results in the emission of any air pollutant not previously emitted.[239] NSPS apply to sources that contribute significantly to "air pollution which may reasonably be anticipated to endanger public health or welfare."[240] Electric power plants and separate sequestration facilities are subject to section 111 requirements, but NSPS covering GHGs have not yet been promulgated. Environmentalists are currently pressuring EPA to require consideration of CCS as

[233] UIC Rule, 75 Fed. Reg. at 77,268.
[234] UIC Rule, 75 Fed. Reg. at 77,269.
[235] UIC Rule, 75 Fed. Reg. at 77,272.
[236] *Id.*
[237] CAA § 111, 42 U.S.C. § 7411 (West 2010).
[238] 40 C.F.R. pt. 60, subpts. D, Da.
[239] *Id.* at (a)(4).
[240] *Id.* at (b)(1)(A).

part of the best available control technology (BACT) determination that becomes part of the requirements imposed on applicants for a GHG permit.[241]

In attainment areas, which are areas that meet the national ambient air quality standards (NAAQS) for all regulated air pollutants to be emitted by the new or modified source, the source must meet the more stringent prevention of significant deterioration (PSD) requirements that include the need for a construction permit that is individually negotiated for each applicant.[242] Only a few new plants have received such permits since 1990, but these plants are held to standards that appear to be as stringent as the emissions projected to be achieved by IGCC technology.

A typical configuration for a new power plant burning low sulfur western coal would have low nitrogen oxide (NO_x) burners, limestone injection into the furnace, particulate collection, a high efficiency advanced selective catalytic NO_x removal system, spray dry absorber flue gas desulphurization system, and a fabric filter. This pollution control technology produces NO_x emissions that are significantly lower than natural gas combined cycle technology using dry low NO_x combustion, which is usually a reverse air pulse jet fabric filter.[243] IGCC technology would presumably also have higher NO_x emissions than a state-of-the-art pulverized coal plant. The controls on high-sulfur fuel are somewhat different and use wet scrubber and wet electrostatic precipitator technology. But these emission controls have no material effect on CO_2 emissions.

As part of the PSD construction permit process, projects must have their environmental impacts assessed.[244] The PSD process includes determining the appropriate technology to require an applicant to use to comply with the CAA § 165(a)(4) requirement mandating the use of the BACT. BACT is defined in CAA § 169(3) to include process changes, fuel substitution, add-on controls and any other available methods to obtain the maximum degree of emission reduction, after considering economic impacts and costs.[245]

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[241] *Activists Urge EPA To Set GHG Performance Standard To Boost Use Of CCS,* XXVII ENVTL POL'Y ALERT (Inside EPA) 15:21 (July 28, 2010).
[242] CAA § 165, 42 U.S.C. § 7475 (West 2010).
[243] *See* Bielawski, *supra* note 14, at 7.
[244] For an overview of the NSR program *see* Arnold W. Reitze, Jr., *New Source Review: Should It Survive*?, 34 ENVTL. L. REP. (ELI) 10673 (July 2004).
[245] CAA § 169(3), 42 U.S.C. § 7479(3) (West 2010). A pulverized coal plant equipped with pulse jet fabric filters can achieve 99.9% particulate removal efficiencies and meet a 0.015 lb/MBtu standard. SO_2 removal up to 95% can be achieved by using a wet scrubber, which allows an emission standard of 0.12 lb/MBtu to be met. Conventional coal-burning power plants combust their fuel at about 3000 degrees Fahrenheit (F) to produce high-pressure steam that is utilized in a high pressure turbine. However, low NO_x burners may be used to keep flame temperatures at about 2500^0F. This limits NO_x formation from the nitrogen in the air while nitrogen in the coal, which is responsible for approximately 80% of the NO_x generated from these facilities, is controlled through a fuel-rich condition using air injection to control stoichiometry. The pollution control devices for NO_x and particulate control will also remove 90% of the mercury. *See Acid Rain; Nitrogen Oxides Emissions Reduction Program*, 61 Fed. Reg. 67112 (Dec.19, 1996) (codified at 40 C.F.R. pt. 76).

In nonattainment areas, which are areas that do not meet the NAAQS for a pollutant that will be emitted, a project is subject to new source review (NSR).[246] Because CO_2 is not a criteria pollutant there can be no CO_2 nonattainment areas, but areas that are nonattainment for other pollutants may be subject to controls for CO_2.[247] In nonattainment areas, CAA § 173(a)(2) requires the lowest achievable emission rate (LAER) to be achieved, which is similar to but more stringent than BACT. For determining the technology that qualifies as BACT/LAER, EPA usually uses a "top-down" analysis, which at a minimum requires compliance with any applicable NSPS.[248] BACT/LAER are source specific and allow the permitting authority to impose more stringent requirements on a permit applicant than otherwise would be imposed by the CAA.[249] LAER is based on the most stringent standard in any SIP or the most stringent standard that is achievable, whichever is more stringent.[250] The primary guidance concerning BACT/LAER requirements is EPA's 1990 New Source Review Workshop Manual.[251]

The PSD process, if applicable, applies to "each pollutant subject to regulation under this chapter emitted from, or which results from, such facility," but in nonattainment areas a new or modified major source must control any pollutant that is subject to a new source performance standard.[252] Air pollutant is defined broadly in CAA § 302(g). In addition to PSD/NSR requirements, states may impose additional standards pursuant to CAA § 116. All states have been delegated the authority to run their nonattainment NSR program; most states have been delegated the authority to run their PSD programs.[253]

An issue of concern has been whether climate change may be addressed in the PSD/NSR process. Are GHG pollutants that are not regulated, but that could legally be regulated, subject to federal PSD/NSR requirements? The answer to this question has been changing over the past three years. On June 2, 2008, EPA's independent Environmental Appeals Board (EAB) rejected a challenge to a refinery expansion project for tar sands processing in Illinois that did not include GHG controls.[254] Similarly, the EAB issued an order that it would not consider CO_2

[246] EPA frequently uses NSR to mean both the PSD and NSR program.
[247] Environmentalists are seeking to have CO_2 declared a criteria pollutant. *Activists Petition EPA for CO2 NAAQS Citing Insufficient Climate Action,* XX CLEAN AIR REP. (Inside EPA) 25:4 (Dec. 10, 2009).
[248] CAA §§ 169(3), 171(3), 42 U.S.C. §§ 7479(3), 7501(3) (West 2010).
[249] CAA §111(a)(3) & (4), 42 U.S.C. § 7411(a)(3) & (4) (West 2010).
[250] CAA § 171(3), 42 U.S.C. § 7501(3) (West 2010). *See also* Sur Contra Contaminacion v. EPA, 202 F.3d 443 (1st Cir. 2000).
[251] ENVTL. PROTECTION AGENCY, NEW SOURCE REVIEW MANUAL: PREVENTION OF DETERIORATION AND NONATTAINMENT AREA PERMITTING (1990), *available at* http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf (last visited Dec. 3, 2010).
[252] CAA §§ 165(a)(4), 171(3), 42 U.S.C. §§ 7475(a)(4), 7501(3) (West 2010).
[253] 40 C.F.R. §§ 51.165 & 51.166 (2010).
[254] *In re* Conoco Phillips Co., EPA EAB PSD Appeal No. 07-02, review denied June 2, 2008. The case was a win for the project's opponents because the EAB remanded the permit to the state to review emission

emissions in the air permit case of *In re: Northern Michigan University Ripley Heating Plant.*[255]

However, other decisions have indicated that CO_2 emissions might be considered to be part of the PSD permit process. EPA's Region 8 granted a PSD permit to the Deseret Power Electric Cooperative's proposed new waste-coal-fired facility near Bonanza, Utah, despite its potential for increasing CO_2 emissions. The granting of the permit was appealed by the Sierra Club to EPA's EAB, which on November 13, 2008, remanded the permit to EPA's Region 8 to reconsider whether to impose CO_2 BACT limits and to develop an adequate record for its decision. The EAB found that the Region wrongly believed its discretion was limited by historical Agency interpretation. The EAB suggested the Region consider whether the public and the Agency would benefit from having the phrase "subject to regulation under the Act" interpreted through a regulation having nationwide scope rather than through this specific permitting proceeding.[256]

In response, on December 18, 2008, EPA's Administrator Stephen Johnson issued a memorandum that restated EPA's position that CO_2 is not a pollutant under the CAA because it is not subject to any regulation that requires actual control of emissions, therefore the Agency is not required to consider CO_2 emissions when it issues permits under the PSD program.[257] However, on February 17, 2009, EPA Administrator Lisa Jackson said the Agency would take a new look at whether CO_2 from power plants should be regulated, and the prior administrator's memorandum should not be considered the final word on the appropriate interpretation of the CAA.[258] This led to a proposed rule to reconsider EPA's position being published in the Federal Register on October 7, 2009.[259]

In 2007, the U.S. Supreme Court held that GHGs, including CO_2, are air pollutants based on the definition found in CAA § 302(g).[260] But even with this holding, EPA had to make an endangerment finding if it was to regulate GHGs. On December 15, 2009, EPA promulgated an endangerment finding that CO_2, methane,

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limitations for conventional pollutants. *See EAB Ruling May Bolster Activists' Bid To Target Tar Sands Refining,* XIX CLEAN AIR REP. (Inside EPA) 12:23 (June 12, 2008).

[255] *Activists Plan Shift To State Suits If EAB Rejects CO2 Permit Limits,* XXV ENVTL POL'Y ALERT (Inside EPA) 22:12 (Oct. 22, 2008).

[256] In Re Deseret Power Electric Cooperative, PSD Appeal No. 07-03 (Nov. 13, 2008). The EAB did not rule on a Sierra Club argument that section 821 of the CAA Amendments of 1990, Pub. L. No. 101-549, 104 Stat. 2399, 2699, which is not codified in the CAA, but which requires monitoring and reporting of CO_2 emissions, is a regulation under the CAA.

[257] EPA's Interpretation of Regulations that Determine Pollutants Covered by Federal Prevention of Signifcant Deterioration (PSD) Permit Program (a.k.a. Johnson Memo),73 Fed. Reg. 80,300 (Dec. 31, 2008).

[258] *Jackson Agrees to Take Fresh Look at Last-Minute CO2 Permit Memo,* XX CLEAN AIR REP. (Inside EPA) 4:26 (Feb. 19, 2009); Steven D. Cook, *EPA Tells Appeals Board It Wants Review Of Gasification For New Mexico Power Plant,* 40 Env't Rep. (BNA) 984 (May 1, 2009)

[259] *Prevention of Significant Deterioration: Reconsideration of Interpretation of Regulations that Determine Pollutants Covered by the Federal PSD Permit Program,* 74 Fed. Reg. 51,535 (Oct. 7, 2009).

[260] 549 U.S. 497, 127 S. Ct. 1438 (2007).

nitrous oxide, hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride in the atmosphere threaten public health and welfare.[261] Thus, when EPA subsequently subjected light-duty vehicles to GHG emissions limits beginning in January 2011,[262] GHGs became regulated pollutants under the CAA, which leads to sources of GHGs being subject to regulation under many provisions of the CAA, including the CAA's PSD/NSR requirements and potentially under other environmental laws.

In anticipation of a final rule on mobile source GHG emissions, on October 27, 2009, EPA promulgated proposed regulations, called the Tailoring Rule, to modify the regulations applicable to the PSD program and the Subchapter V operating permit program to include requirements for regulating GHGs.[263] On June 3, 2010, EPA promulgated its final tailoring rule.[264] EPA decided to subject GHG sources to the PSD permitting program in three steps. Beginning January 2, 2011, sources currently subject to the PSD permitting process must comply with the GHG regulatory program if they are new or are modified to increase emissions above existing significance levels and have total GHG emissions of 75,000 tons per year (tpy) or more on a CO_{2e} basis. No sources will be subject to the CAA permitting requirement solely due to GHG emissions until July 1, 2011. The second step begins July 1, 2011 and runs until June 30, 2013. PSD Permitting requirements will apply to new construction with GHG emissions of at least 100,000 tpy even if they do not exceed the permit threshold for other pollutants. For existing sources, modification will trigger PSD requirements if they emit 75,000 tpy of GHGs, even if they do not significantly increase emissions of other pollutants.[265] For facilities that are subject to operating permit requirements, CO_{2e} requirements will be added. Facilities that do not have an operating permit will be required to obtain one if emissions exceed 100,000 tpy of CO_{2e}.[266] The third step involves another rulemaking to conclude no later than July 1, 2012.[267] EPA's Tailoring Rule may not survive judicial review because its 75,000 and 100,000 tpy triggers for GHGs conflict with CAA §502, which imposes a 100 tpy trigger, and the PSD program's section 169(a), which defines "major emitting facility" as a 100 or 250 tpy source.[268]

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[261] U.S. Envtl. Protection Agency, *Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act,* 74 Fed. Reg. 66,495 (Dec. 15, 2009).
[262] U.S. Envtl. Protection Agency & the U.S. Department of Transportation, *Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule*, 75 Fed. Reg. 25,523 (May 7, 2010).
[263] U.S. Envtl. Protection Agency, *Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule*, 74 Fed. Reg. 55,291, 55,300 (proposed Oct. 27, 2009).
[264] U.S. Envtl Protection Agency, *Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule*: Final Rule, 75 Fed. Reg. 31,513 (June 3, 2010) [hereinafter Tailoring Rule].
[265] Tailoring Rule, 75 Fed. Reg. at 31,523.
[266] Tailoring Rule, 75 Fed. Reg. at 31,524.
[267] Tailoring Rule, 75 Fed. Reg. at 31,525.
[268] 42 U.S.C. §§ 7479, 7661a (West 2010).

To assist state and local permitting authorities, EPA on November 10, 2010, made available "PSD and Title V Permitting Guidance for Greenhouse Gases."[269] The guidance provides that PSD and Title V apply to GHG emissions and BACT determinations will be made by states. EPA does not prescribe GHG BACT requirements, but emphasizes the importance of BACT options that improve energy efficiency.[270] It does say that carbon capture and sequestration, at this time, is unlikely to be considered a BACT requirement. Permits that are effective prior to January 2, 2011 do not need to include GHG provisions. EPA expects permitting authorities to continue to use the five-step top-down analysis for determining the applicable BACT technology.[271] EPA is seeking public comment on the guidance. EPA has also produced "white papers" that provide basic technical information useful for BACT analysis, but they do not define what is BACT. The papers cover seven industrial sectors: electric generating units; large industrial/commercial/institutional boilers; pulp and paper; cement; iron and steel; refineries; and nitric acid plants.[272]

EPA is motivated to increase the GHG threshold for major sources because new GHG regulations will significantly increase applications for PSD permits. The existing PSD program issues 280 permits a year, whereas under new GHG regulations EPA and the states could be required to handle permit application from 41,000 new and modified facilities a year in 2010. In addition, EPA is concerned that one year after GHG regulations for mobile sources become effective six million sources would be required to submit CAA Subchapter V operating permit applications without the Tailoring Rule. These permits would need to be issued within eighteen months after receipt of a complete application. In addition GHG limitations would need to be added to the existing 14,700 Subchapter V operating permits.[273] For this reason states are urging EPA to delay implementation of its Tailoring Rule.[274]

EPA's effort to limit the number of potential permits using the proposed Tailoring Rule would not affect states that have PSD programs that are part of an approved SIP. They must continue to use the 100/250 tpy threshold trigger until a

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[269] U.S. Envtl. Protection Agency, Clean Air Act Permitting for Greenhouse Gases: Guidance and Technical Information (Fact Sheet), *available at* http://www.epa.gov/nsr/ghgdocs/ghgpermittingtoolsfs.pdf (last visited Nov. 20, 2010).

[270] Steven D. Cook, *EPA Issues Guidance to States, Localities On Controls for Greenhouse Gas Sources,* 41 Env't Rep. (BNA) 2504 (Nov. 12, 2010).

[271] *Id.*

[272] *See e.g.,* U.S. Envtl. Protection Agency, Office of Air and Radiation, *Available and Emerging Technologies For Reducing Greenhouse Gas Emissions From Coal-Fired Electric Generating Units* (Oct. 2010), *available at* http://www.epa.gov/nsr/ghgdocs/electricgeneration.pdf (last visited Nov. 25, 2010).

[273] Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, 74 Fed. Reg. 55,291, at 55,302 (proposed Oct. 27, 2009). *See also* Alec Zacaroli, Ben Snowden, and Julie R. Domike, *EPA Begins Regulation of Greenhouse Gas Emissions Under the Clean Air Act,* 40 Env't Rep. (BNA) 2859 (Dec. 11, 2009).

[274] *States Cite Legal Concerns in Urging Delay For EPA GHG Permitting Rule,* XX CLEAN AIR REPORT (Inside EPA) 25:31 (Dec. 10, 2009).

SIP revision is approved. Under the Tailoring Rule or the CAA's 100/250 tpy trigger, existing sources would be subject to permit requirements for any increase in emissions because there is no regulatory "significance level" for CO_2 that limits the applicability of the PSD program. Thus any increase in emissions is considered significant.[275]

EPA on April 2, 2010, promulgated its regulatory interpretation concerning the pollutants covered by the CAA.[276] EPA decided to continue applying the Agency's existing interpretation of 40 C.F.R. § 52.21(b)(50) and the parallel provision in 40 C.F.R. §51.166(b)(49) found in its PSD Interpretive Memo. However, EPA refined its interpretation to establish that PSD permitting requirements apply to a newly regulated pollutant at the time a regulatory requirement to control emissions of that pollutant ''takes effect'' (rather than upon promulgation or the legal effective date of the regulation). EPA also addressed several outstanding questions regarding the applicability of the PSD and Title V permitting programs to GHGs. Except for this change, EPA reaffirmed the PSD Interpretive Memo and its establishment of the actual control interpretation as EPA's interpretation of the phrase ''subject to regulation'' found in the PSD provision in the CAA § 165(a)(4) and EPA regulations that impose technology-based BACT requirements.

EPA concluded PSD program requirements will apply to GHGs from stationary sources on the date that the tailpipe standards for light-duty vehicles (LDV) apply to 2012 model year vehicles, which it determined is January 2, 2011. The emissions control requirements in the rule are applicable to mobile sources by requiring compliance through vehicular certification when a Model Year 2012 vehicle is introduced into commerce. At least seventeen lawsuits have been filed challenging the light-duty GHG vehicle rule.[277]

EPA's position is that the onset of the BACT requirement should not be delayed in order for technology or control strategies to be developed. Furthermore, because of the significant administrative challenges presented by the application of the PSD and Title V requirements for GHGs, it is necessary to defer applying the PSD and Title V provisions for sources that are major based only on emissions of GHGs until a date that extends beyond January 2, 2011. EPA will continue to interpret the definition of ''regulated NSR pollutant'' in 40 C.F.R. §52.21(b)(50) to exclude pollutants which only require monitoring or reporting but to include each pollutant subject to either a provision in the CAA or CAA promulgated regulation that requires actual control of emissions of that pollutant. EPA in its April 2, 2010, interpretation

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[275] *See* 40 C.F.R. § 52.21(b)(23).
[276] U.S. Envtl. Protection Agency, Reconsideration of Interpretation of Regulations That Determine Pollutants Covered by Clean Air Act Permitting Programs: Final Rule*,* 75 Fed. Reg. 17,003 (April 2, 2010).
[277] *EPA GHG Vehicle Rule Faces Slew Of Last-Minute State, Industry Lawsuits,* XXI CLEAN AIR REP. (Inside EPA) 15:34 (July 22, 2010. *See also* Steven D. Cook, *Publication of Greenhouse Gas Tailoring Rule Launches 60-Day Period for Legal Challenges,* 41 Env't Rep. (BNA) 1227 (June 4, 2010); Steven D. Cook, *Chamber of Commerce, Manufacturers Sue EPA Over Greenhouse Gas Regulation,* 41 Env't Rep. (BNA) 1227 (June 4, 2010).

made it clear that provisions in a SIP regulating a pollutant do not make it a nationally regulated pollutant under the CAA that could trigger the need for compliance with other provisions of the CAA.

The CAA's requirements affect carbon sequestration development in the following ways. 1) The CAA's requirements and pending requirements increase the cost and the time required for permitting coal fired electric power plants, which can make alternative energy projects, energy conservation, natural gas electric power generation and nuclear power more attractive by reducing the cost advantage of generating electricity using coal.[278] 2) Sequestration may trigger PSD requirements for the entire electric power generation facility (*see* § 3(b)(1) below). 3) Sequestration could eventually be considered BACT and be required for new or modified electric power facilities, but EPA at this time is not attempting to define CCS as BACT. Alternatively IGCC technology, which makes it easier to sequester carbon, may be considered to be BACT. 4) Sequestration facilities, even if free standing, may require compliance with PSD or NSPS as well as the operating permit requirements found in CAA Subchapter V.[279]

§ 3(b)(1). Sequestration as a PSD/NSR Trigger

EPA has not yet addressed how the Clean Air Act (CAA) requirements apply to plants that install carbon capture equipment. Because of the energy requirements for compressing captured CO_2 prior to transport and sequestration, a power plant will have to burn more fuel to obtain the same net generating capacity. This could increase emissions and potentially trigger the applicability of an NSPS or PSD/NSR requirement. In other words, separating CO_2 from the gas stream could result in new or additional pollution being released, which could trigger NSPS or PSD/NSR applicability.

§ 3(b)(2). IGCC or Sequestration as BACT

Court decisions have held that BACT/LAER requirements cannot be used to force an applicant to redesign a proposed facility. Thus, BACT/LAER cannot be defined to force a proposed coal-burning plant to use alternative energy, gas or nuclear power. For example, on August 24, 2006, EPA's EAB ruled the Agency could not require the use of low sulfur coal at Peabody Energy's Prairie State proposed facility in Illinois because it would redefine the basic design of the facility, which was planned as a mine-mouth facility that would burn high-sulfur Illinois coal.[280]

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[278] The use of federal environmental laws to increase the costs and delay the construction of coal-fired electric power plants is covered in Reitze, *Carbon Constrained*, *supra* note 32.
[279] 42 U.S.C. §§ 7661-7661f (West 2010).
[280] In Re: Prairie State Generating Company, PSD Appeal No. 05-05 (EAB Aug. 24, 2006) available at <http://www.epa.gov/eab> (last visited Apr. 6, 2010).

Subsequently, in *Sierra Club v. EPA,*[281] the Seventh Circuit ruled that EPA does not have to consider whether the applicant should use low-sulfur coal as a pollution control technology because such a requirement would require significant modifications of the plant; BACT review cannot be used to require a redesign of a proposed facility.

An important factor for IGCC technology acceptance is whether it is a BACT requirement for a PSD permit by CAA § 165(a)(4) or a LAER requirement for an NSR permit in nonattainment areas by CAA § 173(a)(2). The difficult question for EPA, or a state permitting authority, is whether IGCC is a pollution control technology that may be required as BACT or a different electric power generating technology that cannot be imposed by a permitting authority.

It has been argued that IGCC is BACT even though it is a different production process and is not an "end of stack" control. This position is supported by the language of CAA § 169(3), which includes different production processes, fuel cleaning, and innovative fuel combustion processes as BACT options. EPA's 1990 draft guidance indicated that it was not the Agency's general policy to redefine an applicant's design for a facility for purposes of considering what is available technology.[282] In the August 6, 2005 Energy Policy Act, Congress stated that it was taking no position as to whether IGCC was adequately demonstrated for purposes of CAA § 111 or whether it is achievable for the purposes of CAA §§ 169 or 171.[283] EPA's Stephen D. Page, however, in a letter dated December 23, 2005, stated that IGCC is not BACT because it involves the basic design of a proposed source.[284] EPA's position was that section 165(a)(2) requires alternative sources to be considered at an early stage in the permitting process, but once a technology is selected section 165(a)(4) requires air pollution control requirements to be based on controls that are appropriate for that technology. Moreover, it is not clear that IGCC is a demonstrated technology or that it results in lower emissions than a state-of-the-art pulverized coal plant.

For PSD and NSR permits, CAA §§ 165(a)(2) and 173(a)(5) provide that a permit may be issued only if an analysis of alternative sites, sizes, production processes, and environmental control techniques for the proposed source demonstrates that the benefits significantly outweigh the environmental and social costs that are imposed by construction or modification. The extent to which alternative analysis can be used to require an alternative be adopted is not clear,

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[281] 499 F.3d 653 (7th Cir. 2007).

[282] United States Envtl. Protection Agency, New Source Review Workshop Manual, Draft 1990, 88 <http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf > (last visited Dec. 3, 2010).

[283] Pub. L. No. 109-58, § 402 (2005).

[284] Steven D. Page, EPA Letter on Use of Integrated Gasification Combined Cycle Technology as BACT, 36 Env't Rep. (BNA) 2666 (Dec. 23, 2005); *see also* Steven D. Cook, *EPA Official Reports Gasification* as *Standard For New Coal-Fired Electric Power Plants,* 36 ENV'T REP. (BNA) 2625 (Dec. 23, 2005).

and this ambiguity is likely to be the subject of challenges to permit applications.[285] If an alternative analysis is to be used to stop a project, who will have the power to determine the social values that are to be considered and how these values are to be balanced?

Currently several cases, EPA administrative hearings, and state proceedings are debating whether IGCC technology can be required as BACT. The Desert Rock coal-fired power plant is planned to be located on Navajo tribal land located in northwest New Mexico. EPA issued a construction permit in 2008. On January 22, 2009, EPA's EAB agreed to hear a challenge to the permit application brought by states and environmentalists. However, on April 27, 2009, EPA asked the EAB to remand *In Re: Desert Rock Energy Company* to the Agency to review the policy regarding whether IGCC technology is BACT.[286] On September 24, 2009, the request for remand was granted. Subsequently Desert Rock was reported to be willing to accept GHG restrictions, but that may not result in a permit because EPA still must decide whether IGCC is BACT.[287] Similarly, on February 18, 2009, the EAB told the Michigan Department of Environmental Quality that it must review a permit for a new power plant at Northern Michigan University to determine whether GHGs should be regulated.[288]

On March 21, 2008, the governor of Kansas vetoed a bill that would have allowed the construction of two coal-fired generation units by the Sunflower Electric Power Corp. The bill was designed to overturn the state's environmental agency's decision to deny a construction permit because of its CO_2 emissions.[289] On April 13, 2009, the fourth attempt by the legislature to approve the plant failed when it was vetoed by the governor, but on May 4, 2009, a new governor agreed to allow one 895 MW plant to be built in place of the two 700 MW units that had been the subject of controversy for two years.[290] On July 1, 2009, EPA said that the

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285 Compare *In re* Hibbing Taconite Co., 2 E.A.D. 838, 1998 EPA App. LEXIS 24, at 11-12; In re Pennsauken County, New Jersey Resource Recovery Facility, 2 E.A.D. 667, 1988 EPA App. LEXIS 27 (Adm'r 1988), with In re Hillman Power Co., Ltd. Liab. Corp., PSD Appeal Nos. 02-04, *et al*, 2002 EPA App. LEXIS 5, at 46-47 (EAB July 31, 1002); In re Kendrall New Century Development, PSD Appeal No. 03-01, 2003 EPA App. LEXIS 3 (EAB April 29, 2003). *See also* Gregory B. Foote, Considering Alternatives: The Case for Limiting CO_2 Emissions From New Power Plants Through New Source Review, 34 ENVTL. L. REP. (ELI) 10642, (July 2004).

286 *EPA Air Permit May Present First Stationary Source CO2 Test For Obama,* XXVI ENVTL POL'Y ALERT (Inside EPA) 2:27 (Jan. 28, 2009); Tripp Baltz, *Colorado Officials Ask EPA to Reconsider Permit Decision for New Mexico Power Plant,* 40 Env't Rep. (BNA) 674 (Mar. 27, 2009).

287 Dawn Reeves, *Industry Seeks Novel GHG Deal With EPA After Permit Remanded,* XXVI ENVTL. POL'Y ALERT (Inside EPA) 20:25 (Oct. 7, 2009). *See also* Steven D. Cook, *EPA Request to Review Desert Rock Permit Violates Clean Air Act, Plant Owner Says,* 40 Env't Rep. (BNA) 1427 (June 19, 2009).

288 *In re* Northern Michigan University Ripley Heating Plant, EAB, PSD Appeal No. 08-02 (Feb. 18, 2009).

289 Susanne Pagano, *Governor Vetoes Legislation to Allow Expansion of Coal-Fired Power Plant,* 39 Env't Rep. (BNA) 623 (Mar. 28, 2008).

290 Christopher Brown, *State Legislature Fails to Override Veto of Bill Allowing Coal-Fired Project,* 39 Env't Rep. (BNA) 923 (May 9, 2008); Christopher Brown, *Governor Vetoes Bill to Allow Construction Of Two Coal-Fired Electric Generators,* 40 Env't Rep. (BNA) 955 (Apr. 24, 2009); Christopher Brown,

Sunflower facility would need to reapply for a construction permit because major changes had been made, and it asked Kansas to consider mandating IGCC as BACT.[291] On June 30, 2010, a draft air permit was released by the Kansas Department of Health and Environment.[292] On November 2, 2010, the Kansas secretary of health and environment who opposed giving Sunflower Electric a permit was asked to step down by the governor.[293] The utility is trying to get a permit before the federal GHG rules take effect January 2, 2010.[294]

In Texas a proposed 800 pulverized coal power plant was the subject of a challenge by environmentalists because it did not plan to use IGCC technology. On January 29, 2009, a Texas state appeals court ruled in *Blue Skies Alliance, et al. v. Texas Environmental Quality Commission* that IGCC is not a viable control technology for a conventional pulverized coal plant, and held a BACT analysis does not require an alternative to be considered that would require a redesign of the proposed facility.[295]

In Georgia, a state court in *Friends of the Chattahoochee, Inc. v. Couch* decided an appeal from a state administrative law judge awarding a construction permit to a coal-fired power plant.[296] The court remanded the case to the agency finding that CO_2 emissions are subject to BACT requirements. The case, now designated *Longleaf Energy Associates LLC v. Friends of the Chattahoochee, Inc.*, was appealed to the Georgia Court of Appeals.[297] On July 7, 2009, the court reversed the lower court holding CO_2 does not have to be regulated and IGCC technology does not have to be considered as part of a BACT analysis.[298] The case was appealed to the Georgia Supreme Court, but *certiorari* was denied on September 28, 2009.[299]

Governor, Energy Company Announce Deal To Allow One New Coal-Fired Power Plant, 40 Env't Rep. (BNA) 1088 (May 8, 2009).

[291] *EPA Asks Kansas To Redo Utility Air Permit To Consider IGCC Controls,* XX CLEAN AIR REP. (Inside EPA) 14:15 (July 9, 2009).

[292] Earthjustice, *KS: Sunflower Coal Plant Draft Air Permit Released* (June 30, 2010), *available at* http://www.earthjustice.org/news/press/2010/ks-sunflower-coal-plant-draft-air-permit-released (last visited Dec. 2, 2010).

[293] *Environmental Activists Decry Dismissal Of State's Top Environmental Regulator,* 41 Env't Rep. (BNA) 2541 (Nov. 12, 2010).

[294] Source Watch, *Holcomb Expansion,* http://www.sourcewatch.org/index.php?title=Holcomb_Expansion (last visited Dec. 2, 2010).

[295] Blue Skies Alliance v. Texas Commission on Envtl. Quality, 283 S.W.3d 525 (Tex.App.-Amarillo 2009).

[296] No. 2008CV 146398, 2008 WL 7531591 (Ga. Super. June 30, 2008). 39 ER 1354 (July 4, 2008).

[297] *Georgia Appeals Court Will Review Ruling Requiring CO2 Limit in Permit.* XIX CLEAN AIR REP. (Inside EPA) 18:11 (Sept. 4, 2008).

[298] 681 S.E. 2d 203 (Ga. Ct. App. 2009), *cert. denied,* S09C1879 2009 Ga. LEXIS 809 (2009). *See* Barney Tumey, *State Appeals Court Overturns Ruling Vacating Building Permit for Coal-Fired Plant,* 40 Env't Rep. (BNA) 1665 (July 10, 2009). Molly Davis, *Activists Scramble to Block Coal-Fired Utility Without CO2 Limits, XX CLEAN AIR REP.* (INSIDE EPA) 21:40 (OCT. 15, 2009).

[299] Case No. S09C1879, 2009 Ga. LEXIS 809 (2009).

The Utah Division of Air Quality and the Utah Air Quality Board, in 2004, granted Sevier Power Company an approval order to construct a coal-fired, circulating fluidized bed power plant. The Sierra Club challenged the approval order. The Board challenged the Sierra Club's standing but lost.[300] The Board, after three days of hearings, granted the approval order. The Sierra Club appealed to the Utah Supreme Court.[301] Review was based on the Utah Administrative Procedure Act under which interpretations of law are reviewed for correctness with little or no deference to the Agency's interpretation. Issues of fact, and the Agency's interpretations are reviewed to determine if they are rational and are set aside only if they are arbitrary and capricious or are beyond the tolerable limits of reason.

The first challenge was based on enforcement provisions in both Utah and federal programs that require a review and possible revocation of a permit if construction has not begun within eighteen months after the issuance of an approval order. The Court agreed with the Sierra Club that this requirement was not followed and remanded the case to the Division to ensure the most up-to-date control technology was adopted and "the increment limits are not tied up indefinitely."[302] Next, after reviewing the confusing history of whether a BACT analysis is required for CO_2, the Court upheld the Board's decision not to require an analysis until EPA formulates a CO_2 emissions policy. This part of the Court's decision is likely to be short lived because EPA regulated CO_2 on May 7, 2010.[303] The most important part of the decision was the Court's finding that IGCC technology is a control technology that should be evaluated as part of a BACT review. The Court concluded that considering IGCC technology would not require Sevier Power to redefine the design of its proposed facility. Consideration of IGCC "does not compel its adoption; instead it only requires the Power Company to subject IGCC to the five-step top down analysis used to determine the best available technology." The Court then went on to say the Board's determination that IGCC was unavailable was unreasonable. The Court set aside the Division's decision and remanded the case. Among the requirements to be met by the Division is that it must conduct a BACT analysis that considers IGCC as an available control strategy.[304]

The uncertainties surrounding the construction permit process and the time required to obtain a permit allow interveners to extract significant concessions from permit applicants in return for dropping a challenge. For example, as part of a TXU buyout, on February 26, 2007, environmentalists announced a nonbinding agreement that eight of eleven proposed coal-fired power plants in Texas would not be built. The company also agreed to expand wind generation and invest $400

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[300] Utah Chapter of the Sierra Club v. Utah Air Quality Bd., 2006 UT 73, ¶ 11, 148 P.3d 975 (2006).
[301] Utah Chapter of the Sierra Club v. Utah Air Quality Board , 209 UT 76, 226 P. 3d 719 (2009).
[302] *Id.* at ¶ 23.
[303] U.S. Envtl. Protection Agency & the U.S. Dep't of Transp., *Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Final Rule*, 75 Fed. Reg. 25,523 (May 7, 2010).
[304] Utah Chapter of the Sierra Club v. Utah Air Quality Board , 209 UT 76, ¶ 46 (2009)..

million in energy efficiency measures.[305] A number of other permit applications show that the requirements to obtain a construction permit is uncertain in this fast changing regulatory environment, and permit applicants may be required to make costly concessions to obtain a permit.[306]

The electric power industry may be giving up their efforts to permit new coal-fired power plants. On July 9, 2009, Intermountain Power announced it would allow its permit to build a new plant in Utah to expire.[307] On December 17, 2009, Seminole Electric announced it was withdrawing its application for a construction permit to build a coal-fired power plant in Florida after three administrative challenges.[308] As mentioned earlier, environmentalists claim plans for 100 new coal-fired plants have been shelved in the U.S. since 2001.[309]

§ 3(b)(3). Sequestration Facilities as a Stationary Source

Sequestration facilities need to be located at sites that will meet government standards. They may be located at a distance from the source of the carbon to be sequestered. They may be under the ownership of an entity that did not generate the carbon to be sequestered. This would make them subject to CAA construction and operating permit requirements, including standards applicable to toxic releases, to the extent that they have emissions sufficient to trigger the various CAA requirements. The primary requirements, however, would be imposed by the SDWA's Class VI permit process that is discussed *supra* at § 3(a).

§ 3(c). Other Federal Environmental Laws

The Solid Waste Disposal Act as amended by the RCRA imposes federal requirements on solid waste and much more stringent requirements on solid wastes that are considered hazardous waste.[310] Solid waste is defined to include discarded material that is solid, liquid, semisolid, or that contains gaseous material.[311] Injection is considered to be "disposal."[312] RCRA probably applies to sequestered carbon, but unless it also is a hazardous waste the more stringent provisions of RCRA Subchapter III will not be applicable. It would seem unlikely that CO_2 would

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[305] *Kansas Pact May Set New Floor For Resolving Coal Plant Disputes,* XVIII Clean Air Rep. (Inside EPA) 7 (Apr. 7, 2007).
[306] *See* Reitze, *Carbon Constrained*, *supra* note 32.
[307] Steve Cook, *With Coal-Fired Plant in Utah Canceled, Sierra Club Says 100 Facilities Shelved,* 40 Env't Rep. (BNA) 1711 (July 17, 2009).
[308] Thom Wilder, *Seminole Electric to Withdraw Application For Coal-Fired Electric Generating Unit,* 41 Env't Rep. (BNA) 33 (Jan. 1, 2010).
[309] Cook, *Coal-Fired Plant*, *supra* note 312.
[310] RCRA §§ 1002-11011, 42 U.S.C. §§ 6901-6992k (West 2010). *See also* 40 C.F.R. § 261.2 (2010).
[311] RCRA §1004(27), 42 U.S.C. § 6903(27) (West 2010).
[312] RCRA § 1004(3), 42 U.S.C. § 6903(3) (West 2010).

be considered a hazardous waste, but even if CO_2 is not a hazardous substance, other hazardous contaminants of a power plant's emission stream could make the sequestered material a mixture that would be considered hazardous.[313] Thus, sequestered CO_2 may meet the definition of hazardous waste.[314] It is not a listed hazardous waste, but it could exhibit specified characteristics to be regulated as hazardous waste.[315] In March 2010 EPA announced it was considering proposing a rule under RCRA to exempt CO_2 waste streams from RCRA's hazardous waste law requirements in order to encourage CCS.[316] Such a decision would be important to industry in large part because of the citizen suit provision in RCRA.

The citizen suit provision of RCRA, section 7002, allows any person to sue 90 days after notice to the defendant, EPA, and the state where the violation is alleged to be occurring.[317] No notice is required if the claim involves a violation of the hazardous substances provisions of RCRA.[318] A section 7002 action allows a plaintiff to enforce the nondiscretionary actions required by RCRA. Private parties cannot obtain money damages, but they may obtain attorney fees and expert witness costs.[319]

However, in EPA's final rule on UIC GS, EPA said the types of impurities and their concentrations would likely vary by facility, coal composition, plant operating conditions, and pollutant removal and carbon capture technologies. "(O)wners or operators will need to determine whether the CO_2 stream is hazardous under EPA's RCRA regulations, and if so, any injection of the CO_2 stream may only occur in a Class I hazardous waste injection well. Conversely, Class VI wells cannot be used for the co-injection of RCRA hazardous wastes (i.e., hazardous wastes that are injected along with the CO_2 stream). EPA supports the use of CO_2 capture technologies that minimize impurities in the CO_2 stream. EPA initiated a rulemaking separate from today's final UIC Class VI rule. The RCRA proposed rule will examine the issue of RCRA applicability to CO_2 streams being geologically sequestered, including the possible option of a conditional exemption from the RCRA requirements for CO_2 GS in Class VI wells. Today's rule does not itself change applicable RCRA regulations."[320]

If a solid waste or a hazardous waste may present an imminent and substantial danger to human health or the environment, RCRA § 7003 allows the Administrator to issue administrative orders and/or sue in a federal district court to obtain equitable relief or enforce the order. Because EPA has found that CO_2 endangers human health, it may be easier to utilize this section.

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[313] 40 C.F.R. § 261.3(a)(2)(iv) (2010).
[314] RCRA § 1004(5), 42 U.S.C. § 6903(5) (West 2010).
[315] RCRA § 3001(a), 42 U.S.C. § 6921(a) (West 2010). *See also* 40 C.F.R. § 261.3 (2010).
[316] *To Speed CCS, EPA Weighs Hazardous Waste Law Exemption For CO2,* XXVII ENVTL POL'Y ALERT (Inside EPA) 6:31 (Mar. 24, 2010).
[317] RCRA § 7002(b)(2) 42 U.S.C. § 6972(b)(2).
[318] *Id.*
[319] RCRA § 7002(e), 42 U.S.C. § 6973.
[320] UIC Rule, 75 Fed. Reg. at 77,260.

CERCLA (a.k.a. Superfund) provides for the clean up of contamination by hazardous substances that occurred in the past from activities that include industrial waste disposal.[321] The statute defines hazardous waste broadly to potentially include sequestered electric power waste streams, and these substances are not covered by the statutes exclusions.[322] CERCLA allows the federal government, state and local governments, and private parties to recover the costs associated with a clean up operation.[323] Private parties that clean up a release may be able to recover from those responsible for the release even if the government is not pursuing a CERCLA action.[324] In addition, some states have superfund statutes that allow for the recovery of damages that are not recoverable under CERCLA.[325]

For CERCLA to apply a disposed substance must be hazardous. Substances that are hazardous under the major environmental statutes are considered hazardous under CERCLA.[326] CO_2 itself is not listed as a hazardous substance under CERCLA, although EPA's endangerment finding for CO_2 under the Clean Air Act could potentially trigger CERCLA liability. More importantly, hazardous contaminants in the CO_2 waste stream could trigger CERCLA liability. "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). Whether such substances may result in CERCLA liability from a GS facility depends on the composition of the specific CO_2 stream and the environmental media in which it is stored (e.g., soil or ground water)."[327] CERCLA § 107 exempts federally permitted releases from triggering liability.[328] This should prevent CERCLA liability, but only if the injectate stream remains within the scope of its SDWA Class VI permit.[329] CERCLA also has the potential to affect state tort law.[330]

One way to avoid the application of RCRA or CERCLA is to have CO_2 classified as a commodity rather than as waste or a pollutant or discarded material. When a CCS regimen is developed it will be important to protect those complying with the requirements of the CCS program from RCRA/CERCLA liability if the private sector is to enter this field. This will also require dealing with the issue of liability for CO_2 waste streams contaminated by H_2S, NO_x, SO_2 and other hazardous substances. Even if CO_2 is not subject to RCRA or CERCLA, it could react with naturally occurring

[321] CERCLA §§ 101-405, 42 U.S.C. §§ 9601-9675 (West 2010).
[322] CERCLA § 101(14), 42 U.S.C. § 9601(14) (West 2010).
[323] CERCLA § 107, 42 U.S.C. § 9607 (West 2010).
[324] United States v. Atlantic Research Corp., 551 U.S. 128 (2007).
[325] Alexandra B. Klass & Elizabeth J. Wilson, *Climate Change and Carbon Sequestration: Assessing a Liability Regime For Long-Term Storage of Carbon Dioxide,* 58 EMORY L. J. 103, 129 (2008).
[326] CERCLA § 101(14), 42 U.S.C. § 9601(14) (West 2010).
[327] UIC Rule, 75 Fed. Reg. at 77,260.
[328] CERCLA §§ 107, 101(10), 42 U.S.C. §§ 9607, 9601(10) (West 2010).
[329] UIC Rule, 75 Fed. Reg. at 77,260.
[330] *See generally* Alexandra B. Klass, *From Reservoirs to Remediation: The Impact of CERCLA on Common Law Strict Liability Environmental Claims,* 39 WAKE FOREST L. REV. 903 (2004).

substances found in the injection site that would yield hazardous substances that would expose responsible parties to potential liability.

The Clean Water Act would not appear to be applicable to releases of CO_2 to the atmosphere, but the Center for Biological Diversity successfully concluded a settlement with EPA to use CWA §303(d) to develop a total maximum daily load (TMDL) for waters threatened or impaired for ocean acidification due to CO_2 emissions. This could lead to CO_2 being considered a hazardous air pollutant (HAP) under CAA §112, because that section defines a HAP as a pollutant that may adversely impact the environment through ambient concentrations or through deposition.[331]

The National Environmental Policy Act (NEPA) of 1969 is becoming a tool used to force federal agencies to consider global climate change as it relates to actions within the agency's jurisdiction.[332] If a federal agency does not comply with NEPA, a legal challenge can be used to slow the progress of proposed projects. Because NEPA is primarily limited to achieving procedural compliance, eventually a federal agency will produce a document that meets the statute's requirements. But delay can be costly and result in a project being abandoned by an applicant. In the energy field the Department of Interior is accustomed to applying NEPA analysis to major projects on public lands. Prior DOI experience with NEPA can help in the transition to new energy technologies. For example, DOI has produced a programmatic environmental impact statement (EIS) for wind projects on Western public lands and is working on an EIS for the development of solar projects on these lands.[333] However, EPA is often exempt from having to comply with NEPA.[334]

Over the past decade, courts have decided several cases involving whether consideration of climate change implications is a necessary part of NEPA analysis. In *Border Power Plant Working Group v. DOE*,[335] the U.S. District Court for the Southern District of California held that NEPA requires an analysis of the global warming implications of federal actions concerning the construction of power lines to carry electricity from new power plants in Mexico to Southern California. In *Mid States Coalition for Progress v. Surface Transportation Board*,[336] the Eighth Circuit held that the Board had violated NEPA by failing to analyze the global warming impacts of a new rail line to transport coal prior to approving the project. The Board then

[331] *Regulators Join Industry In Opposing EPA Use Of Water Law To Curb CO2,* XXI CLEAN AIR REP. (Inside EPA) 12:27 (June 10, 2010).
[332] 42 U.S.C. §§ 4321-4370f.
[333] Robert Miller & Miles Imwalle, *Energy independence achievable with new environmental regulatory approach,* 41 TRENDS (ABA) 2:5 (Nov./Dec. 2009).
[334] *See* Western Nebraska Resources Council v. US EPA, 943 F.2d 867, 871-72 (8th Cir. 1991); and EPA Associate General Counsel Opinion (August 20, 1979).
[335] 260 F. Supp. 2d 997 (S.D. Ca. 2003).
[336] 345 F.3d 520 (8th Cir. 2003).

prepared a minimal Supplemental EIS that resulted in new litigation in which the Eighth Circuit found the SEIS to be adequate.[337]

In the *Center For Biological Diversity v. National Highway Traffic Safety Administration*, the Ninth Circuit on August 18, 2008 remanded a rule entitled "Average Fuel Economy Standards for Light Trucks, Model Years 2008-2011."[338] The petitioners challenge to the rule was based on the arbitrary, capricious, and abuse of discretion standard under the Administrative Procedure Act,[339] in which violations of NEPA and the Energy Policy and Conservation Act of 1975 were alleged.[340] The court remanded the case because of deficiencies in the National Highway Traffic Safety Administration's compliance with both statutes. The court reviewed the requirements imposed by NEPA and found numerous failures to comply with the statute including a failure to adequately assess the cumulative impacts of greenhouse gas emissions on climate change and the environment.[341]

In *Center For Biological Diversity v. U.S. Department of Interior*, the D.C. Circuit on April 17, 2009, ruled that citizens did not have standing to challenge a five-year leasing plan for oil and gas development on the outer continental shelf based on claims that the DOI did not consider the effect on climate change.[342] The court, however, allowed the case to move forward based on claims that the government violated procedural requirements.

While not specific to GHGs or climate change, some rulings concerning the CAA and NEPA have possible implications for projects involving CO_2 emissions, especially in light of the endangerment decision of EPA and the proposed reporting requirements for CCS.[343] In *South Fork Band v. U.S. Department of Interior*, the South Fork Band Council of Western Shoshone of Nevada sued the DOI and its BLM in an effort to stop a gold mining project on the side of Mt. Tenabo in Nevada, after BLM issued a final EIS and approved the project. The plaintiffs in the lower court argued and lost their claims brought under the Religious Freedom Restoration Act.[344] The Ninth Circuit remanded the case to the Federal District Court after reversing the denial of injunctive relief on the NEPA claims. The court granted injunctive relief pending preparation of an EIS that adequately considers the environmental impact of the extraction of millions of tons of refractory ore, mitigation of the of the adverse impact on local springs and streams, and evaluates the emissions of fine particulates.[345]

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337 Mayo Foundation v. Surface Transp. Bd., 472 F. 3d 545 (8th Cir. 2006).
338 538 F.3d 1172 (9th 2008) (remanding the rule found at 71 Fed. Reg. 17,566 (Apr. 6, 2006)).
339 5 U.S.C. §§ 701-706 (West 2010).
340 49 U.S.C. §§ 32901-32919 (West 2010).
341 538 F.3d at 1216.
342 Ctr. for Biological Diversity v. U.S. Dep't of Interior, 563 F.3d 466 (D.C. Cir. 2009).
343 U.S. Envtl. Protection Agency, *Endangerment and Cause or Contribute Findings for Greenhouse Gases under the Clean Air Act,* 74 Fed. Reg. 66,495, 66,496 (Dec. 15, 2009); GHG Reporting, 75 Fed. Reg. 18,576.
344 42 U.S.C. §§ 2000bb-2000bb-4 (West 2010).
345 South Fork Band v. DOI, 588 F.3d 718 (9th Cir. 2009).

The project would impact 6,571 acres of public land and 221 acres of land belonging to the project proponent. South Fork Band argued this violated the FLPMA[346] duty for BLM to take action to prevent "unnecessary and undue degradation of the lands."[347] However, the Ninth Circuit ruled the Tribes failed to demonstrate the likelihood of success in establishing BLM acted in an arbitrary or capricious manner. On the other hand, the court ruled for the Tribes on the NEPA issues. "The air quality impacts associated with transport and off-site processing of the five million tons of refractory ore are prime examples of indirect effects that NEPA requires be considered."[348] The court also was critical of BLM's failure to consider the environmental impact of transportation and processing of the ore. The fact that the facility operates with a state permit issued under the CAA does not satisfy the federal agency's obligations under NEPA.[349] EPA may delegate its permitting authority to the states, but federal agencies must nevertheless comply with NEPA. Moreover, NEPA requires the EIS to discuss mitigation measures with "sufficient detail to ensure that the environmental consequences have been fairly evaluated."[350] The mitigation discussion must include an assessment of whether the proposed mitigation measures can be effective.[351] NEPA requires a hard look be taken before the actions that will impact the environment are taken.[352] The agency's limited understanding of the science applicable to the project does not relieve it of its responsibility under NEPA to discuss mitigation of reasonably likely impacts of the project.[353] Finally, the court required revisions of the modeling and analysis for fine particulates to reflect the recent changes in the EPA standards.[354]

In *Piedmont Environmental Council v. Federal Energy Regulatory Commission,* the Fourth Circuit ruled on the application of NEPA to electric transmission facilities subject to section 216 of the Federal Power Act.[355] The court made it clear that NEPA applies to every proposed transmission project subject to FERC jurisdiction and also requires a programmatic EIS when federal actions are connected or cumulative.[356] The Ninth Circuit has held the BLM must account for the cumulative impacts of all activities in the area in its environmental assessments in two mining cases.[357]

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[346] 42 U.S.C. §§ 1701 *et seq* (West 2010).
[347] 42 U.S.C. § 1732(b) (West 2010). *See also* 43 C.F.R. §3809.5.
[348] 588 F.3d at 725.
[349] *Id*. at 726 (citing Klamath-Siskiyou Wildlands Center v. BLM, 387 F.3d 989, 997 (9th Cir. 2004)).
[350] *Id*. at 727, (citing Robertson v. Methow Valley Citizens Council, 490 U.S. 332,352 (1989)).
[351] *Id.* (citing Robertson v. Methow Valley Citizens Council, 490 U.S. at 351-52).
[352] *Id*. (citing National Parks and Conservation Ass'n v. Babbitt, 241 F.3d 722, 733 (9th Cir. 2001).
[353] *Id.*
[354] *Id*. at 728.
[355] 558 F.3d 304 (4th Cir. 2009), *cert. denied,* No. 09-343 (Jan. 19, 2010). This FPA provision was added by the Energy Policy Act of 2005, Pub.L. No. 109-58, 119 Stat. 594 (2005).
[356] 558 F.3d at 324.
[357] Great Basin Mine Watch v. Hankins, 456 F.3d 955 (9th Cir. 2006); Te-Moak Tribe of Western Nevada v. Dep't of the Interior, 608 F.3d 592 (9th. Cir. 2010).

On February 18, 2010, the Council on Environmental Quality released two draft guidance documents concerning the application of the NEPA process to climate change and GHG emissions.[358] The first document is "Draft NEPA Guidance on Consideration of the Effects of Climate Change and Greenhouse Gas Emissions,"[359] and the second document is "Draft Guidance for NEPA Mitigation and Monitoring."[360] Neither document is to become effective until issued in final form.

The first document affirms the applicability of NEPA and the applicable regulations at 40 C.F.R. parts 1500-1508 to GHG emissions and climate change and the need for federal agencies to reduce their adverse impacts through GHG emission reduction efforts and adaptation measures. The guidance requires agencies to consider the effects of GHG emissions of a proposed action and alternative actions as well as the effects of climate change on the proposed action or alternative actions. Carbon capture and sequestration are among the alternatives that may be considered. The guidance makes a direct annual release of 25,000 metric tpy of CO_{2e} emissions, or more, a base indicator of the need for a quantitative and qualitative assessment. However, long-term releases of less than 25,000 tons of direct or indirect emissions require NEPA-based analysis if the impacts are meaningful. This guidance is not applicable to federal land and resource management, but CEQ "seeks public comment on the appropriate means of assessing the GHG emissions and sequestration that are affected by federal land and resource management decisions." EPA's tailoring rule uses a 75,000 tpy of CO_{2e} threshold for new stationary sources seeking PSD permits, so it is possible that projects that do not require a construction permit will need to comply with NEPA.

The NEPA analysis serves two principal goals. It can reduce vulnerability to climate change impacts by mitigating adverse effects and providing guidance for adaptation response. It can also aid in achieving reductions in GHG emissions through energy conservation measures, reductions in energy use, and by promoting the use of renewable energy technologies. The guidance document encourages the quantification of cumulative emissions over the life of a project and adoption of measures to reduce GHG emissions, including the consideration of reasonable alternatives. An agency may use a programmatic analysis for agency activities that can be incorporated by reference into subsequent NEPA-based analysis for individual projects. The guidance refers to the use of techniques specified in the CAA's mandatory reporting of GHGs rule for the quantification of GHG emissions.[361] The guidance concludes that it is not creating a new component of NEPA analysis,

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[358] *National Environmental Policy Act (NEPA) Draft Guidance, Consideration of the Effects of Climate Change and Greenhouse Gas Emissions,* 75 Fed. Reg. 8,046 (Feb. 23, 2010).

[359] The draft guidance may be downloaded from http://ceq.hss.doe.gov/nepa/regs/Consideration_of_Effects_of_GHG_Draft_NEPA_Guidance_FINAL_02182010.pdf (last visited Dec. 3, 2010).

[360] The draft guidance may be downloaded from http://preti.com/CEQ-Issues_Draft_NEPA-Guidance-Regarding-Greenhouse-Gases (last visited Dec. 3, 2010).

[361] U.S. Envtl. Protection Agency, Mandatory Reporting of Greenhouse Gases, 74 Fed. Reg. 56,259 (2009) (to be codified at 40 C.F.R. pts. 86,87,89).

but climate change is a potentially important factor to be considered within the existing NEPA framework.

The second document provides guidance concerning how mitigation and monitoring of GHGs should be treated in the NEPA process. The document's appendix includes an overview of the Department of the Army Regulation, which the CEQ considers to be a model that should be adopted by other agencies.[362] Mitigation is to be used " to avoid, minimize, rectify, reduce, or compensate the adverse environmental impacts associated with [agency] actions."[363] Mitigation measures should be binding commitments. Monitoring is to ensure mitigation measures are implemented and are effective. Public participation should be supported through proactive disclosure. Mitigation goals should be clear and subject to measurable performance standards. Mitigation can be in the form of alternatives, and it can be an integral element in the design of a project. If mitigation is used to avoid the need for an EIS, it should be binding and enforceable and included in the finding of no significant impact (FONSI). A substantial mitigation failure, in either implementation or effectiveness, should trigger a response from the agency.

Monitoring should ensure that mitigation agreements by agencies are carried out. The lead federal agency is responsible for ensuring mitigation requirements are carried out and the monitoring information is available to the public through online or print media. If mitigation measures required to reduce environmental impacts below significance levels are found to be ineffective, an EIS should be prepared.

The draft CEQ guidance provides an exemption from NEPA-based review for federal land management activities involving oil and gas leasing. This has led to a lawsuit in which a federal district court in New Mexico agreed to hear a challenge to the BLM's granting of oil and gas leases without considering emissions of the GHG methane.[364]

In addition to NEPA obligations, federal agencies must comply with applicable executive orders. On October 5, 2009, Executive Order 13514, Federal Leadership in Environmental, Energy, and Economic Performance, declared "that Federal Agencies shall increase energy efficiency; measure, report, and reduce their greenhouse gas emissions from direct and indirect activities." To implement this policy a "Strategic Sustainability Performance Plan" must be developed. This executive order adds to the requirements for GHG reporting and requires agency-wide reductions in GHG emissions, but it does not specifically address carbon sequestration. It does require planning to reduce GHG emissions from sources

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[362] The Army's regulations are found at 32 C.F.R. § 651 (2010).

[363] Nancy H. Sutley, Chair, CEQ. Draft Guidance for NEPA Mitigation and Monitoring. Memorandum for Heads of Fed. Depts. and Agencies. Feb. 18, 2010.

[364] Amigos Bravos v. Bureau of Land Mgmt., No. Cir. 09-0037, slip op. (D.N.M. Feb. 9, 2010); *see also* Molly Davis, *Court To Weigh GHG Review For Federal Lands Exempt Under NEPA Guide,* XXVII ENVTL. POL'Y ALERT (Inside EPA) 5:26 (Mar. 10, 2010).

controlled by a federal agency and reductions in GHG emissions from the generation of electricity purchased by a federal agency. On January 29, 2010, President Obama announced that the federal government is to reduce its GHG emissions by 28 percent by 2020. The federal target is based on the aggregate of 35 federal agencies self-reported targets.[365]

In March 2010 the Forest Service endorsed a "no action" alternative to oil and gas exploration in Bridger-Teton National Forest because of unacceptable levels of air pollution after the federal Interior Board of Land Appeals reopened the EIS because it failed to consider air quality impacts and the effects on the Canada lynx.[366]

On April 6, 2010, DOE published a notice that it would prepare an EIS for a 390 MW power plant located near Tupman, California[367] because the facility is eligible for a Coal Power Initiative grant of $308 million, which will cover about eleven percent of the project's cost.[368] The plant plans to gasify coal and petcoke to produce synthetic gas. CO_2 will be captured and transported to an underground injection site. NEPA's requirements provide EPA the opportunity to pressure other agencies to add mitigation measures to proposed projects. For example, EPA's Region IX asked the BLM to consider voluntary mitigation measures, including the purchase of offset credits, before approving the White Pine Energy Station Project in Nevada.[369] DOE is planning to prepare EISs for two CCS projects it is helping to fund in West Virginia and Texas.[370]

After the British Petroleum oil spill in the Gulf of Mexico, President Obama announced on May 14, 2010, that the Council on Environmental Quality (CEQ) and the DOI would review whether the Mineral Management Service is meeting its NEPA obligations.[371] Such a review could impact other DOI leasing programs, including CCS. The State Department, for example, has agreed to expand its NEPA review of the permit application to construct a pipeline to move high-carbon tar sands oil from Canada to refineries in Texas.[372] This project is opposed by environmentalists

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[365] President Obama Sets Greenhouse Gas Emissions Reduction Target for Federal Operations, White House Press Release (Jan. 29, 2010), *available at* http://www.whitehouse.gov/the-press-office/president-obama-sets-greenhouse-gas-emissions-reduction-target-federal-operations (last visited Dec. 3, 2010).

[366] Stuart Parker, *In Major Reversal, Forest Service Opposes Drilling EIS Due To Air Impacts,* XXI CLEAN AIR REP. (Inside EPA) 7:31 (Apr. 1, 2010).

[367] Hydrogen Energy California's IGCC Project, Notice of Intent To Prepare an EIS and Notice of Potential Floodplain and Wetlands Involvement, 75 Fed. Reg. 17,397 (Apr. 6, 2010).

[368] Ari Natter, *Energy Department to Examine Proposal For Kern County, Calif., Carbon Project,* 41 Env't Rep. (BNA) 782 (Apr. 9, 2010).

[369] Nick Juliano, *White House Faces Test On GHG Emissions Threshold For NEPA Guidelines,* XXI CLEAN AIR REP. (Inside EPA) 12:27 (June 10, 2010).

[370] Steven D. Cook, *DOE Seeks Comment on Assessments Of Carbon Capture Projects in Two States,* 41 Env't Rep. (BNA) 1298 (June 11, 2010).

[371] Charlotte Tucker, *Obama Orders Review of NEPA Policy; BP Exploration Plan Minimized Spill Impacts,* 41 Env't Rep. (BNA) 1155 (May 21, 2010).

[372] *Pipeline Permit Delay May Allow State Dept. To Address GHG Concerns,* XXI CLEAN AIR REP. (Inside EPA) 16:17 (Aug. 5, 2010).

because the life cycle carbon emissions of oil from tar sands is about 82 percent greater than crude oil refined in the U.S.[373]

The Internal Revenue Service (IRS) plays a role in CCS because Congress in the Energy Improvement and Extension Act of 2008 provided tax credits for taxpayers that capture and sequester CO_2 from a qualified facility. The IRS issued guidance 2009-44 IRB (IRS, 2009) for taxpayers seeking to claim tax credits for capturing and sequestering CO_2. Under IRC § 45Q, a taxpayer who stores CO_2 under the predetermined conditions may qualify for the tax credit of $10 per metric ton of qualified CO_2 at ER projects or $20 per metric ton of qualified CO_2 at non-ER projects. The tax credit amounts will be adjusted for inflation for any taxable year beginning after 2009. To provide guidance regarding eligibility for this tax credit, computation of the tax credit, reporting requirements concerning the tax credit, and rules regarding adequate security measures for "secure geological storage of CO_2" the Internal Revenue Service published IRS Notice 2009-83. Taxpayers claiming the section 45Q tax credit must follow the appropriate SDWA's UIC requirements (e.g., Class II or Class VI), which includes following the SDWA's monitoring, reporting, and verification procedures finalized in the CO_2 Injection and Geologic Sequestration Reporting Rule that is part of the GHG Reporting Program.[374]

§ 3(d). Laws Administered by The Department of the Interior

The BLM within the DOI has jurisdiction over CO_2 injected on federal lands. BLM does not regulate pipelines, but it is the agency that grants rights-of-way to place pipelines on federal lands. It is not clear whether BLM has authority to establish a funding mechanism for management of sequestration on its lands.[375] Moreover, it has not yet been resolved which federal agency will have oversight over long-term liability for sequestration or other aspects of the program.[376] The Climate Change Technology Program (CCTP) that was authorized by the Energy Policy Act of 2005 is charged with interagency coordination and can be expected to play a role in CCS development.[377]

The Energy Independence and Security Act of 2007 expanded DOI's responsibility for carbon sequestration.[378] Section 714 of the 2007 Act directs DOI to report on its framework for managing geological sequestration on public lands. Section 711 directs DOI to develop a methodology for assessing the potential for geologic storage of CO_2 and to use the methodology to assess the nation's capacity

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[373] *EPA Backs Growing Calls For GHG Analysis Of Key Tar Sands Pipeline,* XXVII ENVTL POL'Y ALERT (Inside EPA) 15:23 (July 28, 2010).
[374] UIC Rule, 75 Fed. Reg. at 77,236.
[375] GAO, *supra* note 45, at 30.
[376] Energy Law Gives EPA Shared Powers Over CO2 Storage Program, XIX CLEAN AIR REP. (Inside EPA) 2:8 (Jan. 24, 2008).
[377] Pub. L. No. 109-58 (Aug. 8, 2005).
[378] Pub. L. No. 110-140 (2007).

for storage. Section 712 requires DOI to assess the capacity of ecosystems to sequester carbon. Section 713 requires DOI to maintain records, and an inventory, of the quantity of CO_2 stored within federal mineral leaseholds. Section 714 directs DOI to report on its recommended regulatory framework for managing geologic carbon sequestration on public lands. DOI is to assess the options for obtaining fair market value for using public lands, procedures for public participation in the process, and recommend procedures for protecting natural and cultural resources. It must also assess the status of liability related to geologic sequestration on public land, including situations where the government owns the mineral rights but not the overlying surface estate. DOI is to identify issues relating to pipeline rights-of-way. It is to recommend additional legislation that may be needed to carry out its responsibilities for land management, leasing, and pipeline rights-of-way.

On June 3, 2009, the report, entitled "Framework for Geological Carbon Sequestration on Public Land" was released.[379] The report recommends criteria for identifying potential sites for geological carbon sequestration and proposes a regulatory regime for leasing public lands for sequestration. The report identifies four challenges that need to be addressed in developing a regulatory regimen. First, it must be determined whether CO_2 is "a commodity, resource, contaminant, waste, or pollutant", and pure CO_2 must distinguished from the mixtures containing hydrogen sulfide, carbon monoxide, methane, oxides of nitrogen and sulfur, and other contaminants that can be expected to be found in sequestered streams of CO_2.[380] Second, potential conflicts with other lands uses, including mining, oil and gas production, coal production, geothermal development, ground water use as well as potential impacts on surface land uses such as recreation, grazing, cultural resources, and community development need to be addressed.[381] Third, the issue of long-term liability including its scope and the terms of stewardship needs to be addressed, including the potential conflict of sequestration with the BLM's mandate to manage public lands for multiple uses.[382] Fourth, geological carbon sequestration on public lands involving split estates or lands where the surface is managed by agencies other than BLM need to be addressed.[383]

Currently there is no specific authority for leasing lands administered by BLM for CCS. However, FLPMA authorizes the Secretary of Interior to issue leases, permits, and easements for the use, occupancy, and development of the public lands.[384] Carbon sequestration on public lands will require amending the applicable BLM Resource Management Plan (RMP).[385] Because CCS leases could prevent future uses of the land for other purposes or withdrawal of the land for military or other

[379] U.S. Dept. of the Interior, *Framework for Geological Carbon Sequestration on Public Land* (June 3, 2009).
[380] *Id.*at 1.
[381] *Id.*
[382] *Id.*
[383] *Id.* at 2. BLM is responsible for 700 million acres of lands with federal mineral estates. *Id.* at 10.
[384] 43 U.S.C. § 1732(b).
[385] U.S. Dep't of the Interior, Framework for Geologic Carbon Sequestration, *supra* note 94, at 10.

federal uses, it is expected that Reasonable Foreseeable Development Scenarios (RFDS) similar to the process used for oil and gas leasing will be required prior to leasing.[386] Leasing provisions of the MLA will be applicable.[387] It is unclear what federal liability under the MLA will be for carbon sequestration on lands administered by BLM or what BLM's options will be if its property interests are adversely affected. If the mineral estate has been split then determining the obligations and benefits of interests in land will be further complicated.[388]

The Endangered Species Act (ESA) is another statute that could be a barrier to geological carbon sequestration. The law was enacted in 1973[389] and has been amended a number of times, most recently in 1988.[390] The purpose of the Act includes the conservation of ecosystems upon which endangered and threatened species depend. The statute requires all federal departments and agencies to use their authority to conserve endangered and threatened species and to cooperate with State and local agencies to resolve water issues to conserve these species.[391] The Secretaries of Commerce and Interior share the responsibility for achieving the Act's goals.[392] The Department of Interior delegates implementation of the Act to the Fish and Wildlife Service (FWS).[393] The Department of Commerce delegates responsibility to the National Marine Fisheries Service (NMFS) within the National Oceanic and Atmospheric Administration (NOAA).[394]

FWS and NMFS determine which species are endangered or threatened based on ESA § 4 criteria.[395] After a species is listed, regulations must be promulgated to conserve the species,[396] and a recovery plan must be developed and implemented to protect the species.[397] Designating critical habitat is mandatory unless it is not prudent or not determinable.[398] The ESA § 11 contains numerous prohibitions to prevent harm to listed species,[399] as well as a permit program that allows incidental taking of a listed species.[400] Violations of the Act can result in the imposition of civil or criminal penalties.[401]

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[386] *Id.* at 7.
[387] 30 U.S.C. § 226.
[388] U.S. Dep't of the Interior, Framework for Geologic Carbon Sequestration, *supra* note 94, at 12.
[389] Pub. L. No. 93-205, 87 Stat 884 *et.seq* (Dec. 28, 1973). The Act repealed the Endangered Species Conservation Act of 1969, Pub. L. No. 91-135 (1969), which modified the Endangered Species Preservation Act of 1966, Pub. L. No. 89-669 (1966).
[390] The Act is codified at 16 U.S.C. §§ 1531 – 1544.
[391] 16 U.S.C. § 1531(b) & (c).
[392] 50 C.F.R. pt. 402.
[393] Regulations are found at 50 C.F.R. pts 17, 451-453.
[394] Regulations are found at 50 C.F.R. Part 222-224 pertaining to this responsibility.
[395] 16 U.S.C. § 1533.
[396] 16 U.S.C. § 1533(d).
[397] 16 U.S.C. § 1533(f).
[398] Center for Biological Diversity v. U.S. Fish & Wildlife Service, 450 F.3e 930, 935 (9th Cir. 2006). Non determinable is defined at 50 C.F.R. § 424.12(a)(2).
[399] 16 U.S.C. § 1538.
[400] 16 U.S.C. § 1539.
[401] 16 U.S.C. § 1540.

Climate change already is adversely affecting animal and plant species. In Yosemite National Park, for example, pika habitat has moved from 7,800 feet to 9,500 feet, which diminishes its habitat.[402] In Hawaii, some native birds are now rarely found below 4,500 feet.[403] A decline in the Walrus population in the Pacific Ocean is believed to be the result of climate change.[404] Petitions seeking the listing of ten penguin species and three seal species have been filed.[405] On January 5, 2010, NOAA proposed designating more than 70,000 square miles of critical habitat for the leatherback turtle off of the West Coast of the U.S. This could impact any offshore oil, gas or wind project that may require federal regulatory approval.[406]

In the Arctic the plight of the polar bear due to climate change has been well documented and resulted in the bear being listed as threatened by the FWS.[407] The ESA § 4 gives FWS and NMFS the right to designate critical habitat,[408] but because there is no discrete area that can used to protect the polar bear from the effects of climate change, the FWS found its critical habitat was indeterminable.[409] The ESA § 4(f) requires recovery plans for the conservation of endangered and threatened species unless a plan would not promote conservation of species.[410] This provision has the potential to be imposed on energy development activities. The ESA § 7 requires each federal agency to consult with FWS or NMFS to ensure that any action authorized, funded, or carried out by the agency is not likely to jeopardize the continued existence of any endangered or threatened species.[411] If jeopardy is found additional requirements are applicable.[412] A FWS memorandum of May 14, 2008, said that ESA § 7's consultation requirement was not applicable to sources of GHG emissions because of the lack of data to establish the causal connection with adverse effects on listed communities.[413] However, as data continues to be collected and evaluated this position could change.

In *Natural Resources Defense Council v. Kempthorne* a coalition of environmental organizations filed an action against the DOI and FWS challenging a biological opinion (BiOP) issued by FWS pursuant to the ESA that concluded water

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402 Lawrence Liebesman, Elizabeth Lake, and Peter Landreth, *The Endangered Species Act and Climate Change,* 39 Envtl L. Rep. (ELI) 11173, 11174 (Dec. 2009).
403 *Id.*
404 Yereth Rosen, *Results of Pacific Walrus Survey Suggest Population Decline, Effects of Climate Change,* 41 Env't Rep. (BNA) 84 (Jan. 8, 2010).
405 Liebesman, *supra* note 407, at 11176.
406 Tom Alkire, *70.000 Square Miles of Critical Habitat Proposed for Sea Turtles on West Coast,* 41 Env't Rep. (BNA) 84 (Jan. 8, 2010).
407 *Determination of Threatened Status of the Polar Bear Throughout Its Range*, 73 Fed. Reg. 28212 (May 15, 2008.
408 16 U.S.C. § 1533.
409 73 Fed. Reg. at 28,298.
410 16 U.S.C. § 1533(f).
411 16 U.S.C. § 1536(a).
412 16 U.S.C. § 1536(b).
413 Memorandum from Dave Hall, Director, F&WS, to Regional Directors, Regions 1-8, Expectations for Consultations on Actions That Would Emit Greenhouse Gases (May 14, 2008).

diversion projects in the California Bay Delta area would not jeopardize the Delta smelt (Hypomesus transpacificus).[414] A final BiOp is a "final" agency action[415] for judicial review based on the Administrative Procedure Act.[416] An important part of the decision was the court's holding that the failure of the BiOp to consider data on climate change was arbitrary and capricious. The usual deference to an agency is not owed when the agency fails to address a factor that is essential to making an informed decision.[417] Moreover the court held that mitigation measures included in the BiOp "must be reasonably specific, certain to occur, and capable of implementation; they must be subject to deadlines or otherwise-enforceable obligations; and most important, they must address the threats to the species in a way that satisfies the jeopardy and adverse modification standards."[418] The BiOP must evaluate the proposed action on the survival of the species and any potential destruction or adverse modification of its critical habitat. Both direct and indirect effects must be evaluated.[419] A proposed project should help critical habitat recover.[420]

The best available science should be used to prepare the BiOp, which gives "the benefit of the doubt to the species."[421] In *Conner v. Burford,* the Ninth Circuit used the benefit of doubt language in a challenge to oil and gas leases on National Forest Land.[422] The court held FWS violated the ESA by failing to use the best information available to prepare a comprehensive biological opinion. Although the precise location of future oil and gas activities were unknown, there was extensive information concerning the habitat of species covered by the ESA for the areas subject to the proposed leases. Thus FWS could have determined whether post-leasing activities were incompatible with the continued existence of protected species.[423]

The climate change issue was important aspect of the planning to protect the Delta Smelt, because the BiOp assumed the hydrology of the water bodies affected by the project would follow historical patterns. The court found that many studies have been produced dealing with the impact of global warming on water availability in the Western United States. At the very least FWS should analyze this issue.[424]

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[414] 506 F. Supp.2d 322 (E.D. Ca. 2007).
[415] 5 U.S.C. § 706(2)(A,D). *See* Bennett v. Spear, 520 U.S. 154, 178 (1977).
[416] ESA § 2 *et seq.,* 16 U.S.C. § 1531 *et seq. See* American Rivers v. Nat'l Marine Fisheries Serv., 126 F.3d 1118, 1124-25 (9th Cir. 1997).
[417] 506 F. Supp.2d at 348.
[418] 506 F. Supp.2d at 350, 359, *citing* Ctr. for Biological Diversity v. Rumsfeld, 198 F. Supp.2d 1139, 1152 (D. Ariz. 2002) *citing* Sierra Club v. Marsh, 816 F.2d 1376 (9th Cir. 1987).
[419] 506 F. Supp.2d at 331-32, 383. *See also* Thomas v. Peterson, 753 F.2d 754,763 (9th Cir. 1985). To determine whether actions are considered interrelated or interdependent to the primary action, the court refers to the Endangered Species Consultation Handbook, which provides guidance on this issue.
[420] Gifford Pinchot Task Force v. U.S. Fish & Wildlife Serv., 378 F.3d 1059, 1069 (9th Cir. 2004).
[421] 506 F. Supp.2d at 361.
[422] 848 F.2d 1441, 1454 (9th Cir. 1988).
[423] *Id.* at 1454.
[424] 506 F. Supp.2d, at 369.

"FWS acted arbitrarily and capriciously by failing to address the issue of climate change."[425]

A year after the *Kempthorne* decision the same Federal District Court ruled on a similar case, the *Pacific Coast Federation of Fisherman's Associations v. Gutierrez.*[426] This case involved a challenge by fishermen's associations, environmental groups, and an Indian Tribe to an ESA BiOp that was issued by NMFS for three species of salmon. The defendants were the Department of Commerce and the Bureau of Reclamation and the target was California's Central Valley project, which is the largest federal water management project in the United States. Among numerous claims for relief were the claim that NMFS failed to consider climate change and its impact on the hydrology of Northern California's river systems.[427] Another claim was that the conclusion in the BiOp of no jeopardy was unsupported by the record.[428] The court held that scientific data concerning the effects of climate change on the hydrology of the project area were readily available.[429] However, the court denied the Fisherman's motion for summary judgment because the consideration of the effects of climate change was not required by established law at the time the BiOp was completed. But the Bureau nevertheless was required to complete a legally sufficient BiOp, which by definition included considering global climate change.[430]

There are more than one hundred species in the Western United States that qualify for protection under the ESA or under state programs for sensitive species. Species of concern include fish, amphibians, reptiles, birds, mammals, and mollusks.[431] BLM has rescinded drilling permits for coal-bed methane projects in Wyoming because of concern for elk habitat.[432] The Prairie Dog Recovery and Implementation Plan is a limitation on economic development in southern Utah.[433] Restrictions imposed by the BLM to protect the sage-grouse concern the oil and gas industry and the wind energy industry.[434] On March 5, 2010, the Fish and Wildlife

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[425] 506 F. Supp.2d, at 371.
[426] 606 F. supp.2d 1122 (E. D. Cal. 2008).
[427] *Id.* at 1150.
[428] *Id.*
[429] *Id.* at 1183.
[430] *Id.* at 1190.
[431] *See e.g.* State of Utah, *Utah Sensitive Species List*, *available at* http://dwrcdc.nr.utah.gov/ucdc/ (last visited Dec. 3, 2010). *See also* J.B. Ruhl, *Adapting the Endangered Species Act to climate change,* 41 TRENDS (ABA) 2:8 (Nov./Dec. 2009).
[432] Tripp Baltz, *Wyoming BLM Office Halts Oil, Gas Drilling After Concerns Raised About Elk Habitat,* 40 Env't Rep. (BNA) 2902 (Dec. 18, 2009).
[433] Mark Havnes, *Plan Could Make Peace Between Humans, Beasts,* SALT LAKE TRIBUNE, Feb. 15, 2010, at B5.
[434] Tripp Baltz, *BLM Office in Wyoming Issues Policy For Sage Grouse, Resource Planning,* 41 Env't Rep. (BNA) 82 (Jan. 8, 2010); Tripp Baltz, *Departments of Agriculture, Interior Reach Agreement on Sage Grouse Habitat,* 41 Env't Rep. (BNA) 851 (Apr. 16, 2010). The wind energy off the coast of Massachusetts is being challenged based on the Endangered Species Act and the Migratory Bird Treaty. Martha Kessler, *Opponents of Nantucket Sound Wind Farm File Lawsuit in Federal Court To Halt Project,* 41 Env't Rep. (BNA) 1462 (July 2, 2010).

Service added the sage-grouse to the list of candidate species for protection under the ESA.[435] Oil, gas, and coal-bed methane development as well as wind energy development are negatively affecting sage-grouse populations, which has resulted in an agreement by the Departments of Agriculture and Interior, signed on April 13, 2010, to promote and preserve the habitat of the greater sage grouse and sagebrush ecosystems in the eleven Western states.[436] Other species that are the basis of efforts to prevent energy development included Penguins[437] and Beluga Whales. [438]

A CCS program will require the construction of a pipeline system, which may be subject to environmental opposition. For example, the Ruby gas pipeline that will run from Wyoming to Oregon is a project of a subsidiary of El Paso Corporation. It has been the target of litigation brought by the Center for Biological Diversity based on a claim it will harm species such as the Lahontan cutthroat trout, Warner Creek sucker, Lost River sucker and the Colorado pikeminnow. Two other environmental groups ended their opposition after El Paso agreed to spend $20 million to protect sagebrush habitat, but an association of ranchers is seeking $15 million for rangeland improvements and the Sierra Club is seeking to force the use of a longer alternative route with less adverse environmental impact.[439]

§ 3(e). The Department of Energy

The DOE, primarily through NETL, has been active in promoting the development of a framework and infrastructure needed to validate and deploy carbon sequestration technologies. DOE established its carbon sequestration program in 1997. It created seven Regional Carbon Sequestration Partnerships (RCSPs) with more than 350 organizations in forty-three states, three Native American Organizations, and four Canadian provinces as participants.[440] The seven regional partnerships encompass 97% of the nation's coal-fired CO_2 emissions, 97% of the industrial CO_2 emissions, 96% of the U.S. land, and nearly all of the potential sequestration storage sites.[441] The partnership program was to develop

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[435] U.S. Fish and Wildlife Service, *Endangered Species Act Listing Decision for the Greater Sage-Grouse* (Mar. 5, 2010).

[436] *Id.* Nevertheless, the Fish and Wildlife Service is being sued for not acting aggressively enough to protect the sage-grouse. Tripp Baltz, *Activists Sue Fish and Wildlife for Delaying Protection of Sage Grouse in Western States,* 41 Env't Rep. (BNA) 1540 (July 9, 2010).

[437] Carolyn Whetzel, *Agency to List Penguins for Protection From Threats Posed by Climate Change,* 41 Env't Rep. (BNA) 1316 (June 11, 2010).

[438] Yereth Rosen, *State Sues NOAA to Overturn Listing of Cook Inlet Beluga Whales as Endangered,* 41 Env't Rep. (BNA) 1319 (June 11, 2010.

[439] Mead Gruver, *Group Sues to Block Ruby Pipeline,* SALT LAKE TRIBUNE, Aug. 1, 2010, at B5; *Ranchers Reach Tentative $15M Deal over Ruby Pipeline,* SALT LAKE TRIBUNE, Aug. 9, 2010, at B6.

[440] http://www.netl.doe.gov/technologies/carbon_seq/partnerships/partnerships.html (last visited Dec.3, 2010).

[441] http://fossil.energy.gov/programs/sequestration/partnerships/ (last visited Dec. 3, 2010). The RCSPs are: Big Sky RCSP; Plains CO_2 RCSP; Midwest Geological Sequestration Consortium; Midwest Regional

partnerships, identify potential carbon sources and projects, and evaluate infrastructure needs, establish monitoring, mitigation, and verification protocols and implement sequestration projects. The DOE's RCSPs' initiative is being implemented in three phases: the characterization phase (2003-2005); the validation phase involving small scale field tests (2005-2010); and the development phase that involves large scale carbon storage projects (2008-2017).[442] Data from the partnerships characterizing sources and sinks are integrated into the National Carbon Sequestration Database and Geographic Information System (NATCARB).[443] The RCSPs have assessed the storage capacity for CO_2 and published their findings in November 2008.[444]

Other DOE programs related to sequestration include: the IGCC and FutureGen programs previously discussed, the Innovations for Existing Plants program, and the Clean Coal Power Initiative, which supports research and development of advanced coal-based technologies that capture and sequester CO_2 emissions.[445] DOE also is charged with monitoring, verification and accounting for the sequestration program in order to demonstrate projects meet the DOE goal of 95% to 99% retention. A challenge for this effort is to develop the technology and procedures to assure leakage of 5% or less can be detected.[446]

In Phase III of the RCSP program nine large-scale projects represent a major expansion of the twenty-two small-scale projects that were part of the validation phase. The Southwest Regional Partnership includes Arizona, Colorado, Kansas, New Mexico, Oklahoma, Texas, Utah, and Wyoming. The partnership plans to work with Resolute Natural Resources Company and the Navajo Nation Oil Company to inject CO_2 for 3.5 years leading up to 150,000 tpy. This is equivalent to the CO_2 produced by a 1,000 MW_e plant in about nine minutes of operation.[447] The injection site is the Greater Aneth Field, which is the largest oil field in the Paradox Basin located in Southeast Utah near Bluff, Utah. The CO_2 will come from the McElmo Dome and is 98% pure. It arrives at a pressure of about 2,750 psi, which allows injection without additional compression.[448]

The Southeast RCSP will inject CO_2 into Tuscaloosa Massive Sandstone at two locations. The first stage involves injecting 1.5 million tons of CO_2 a year into the saline reservoir associated with an oil field. The second stage will be to inject post-

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Sequestration Partnership; Southeast RCSP; Southwest Regional Partnership on Carbon Sequestration; and the West Coast RCSP.

[442] http://www.netl.doe.gov/technologies/carbon_seq/partnerships/partnerships.html (last visited Dec. 3, 2010).

[443] www.natcarb.org/ (last visited Dec. 3, 2010).

[444] 2008 Carbon Sequestration Atlas of the United States and Canada, available at http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlasII (last visited Mar. 3, 2010).

[445] GAO, *supra* note 45, at 14.

[446] http://www.netl.doe.gov/technologies/carbon_seq/core_rd/mva.html (last visited Dec.3, 2010).

[447] This assumes about one ton of CO_2 is emitted for each MWhr.

[448] Energy & Geoscience Institute, The University of Utah, *available at* http://co2.egi.utah.edu/projectsites/paradox/index.htm (last visited Dec.3, 2010).

combustion CO_2 from an existing power plant into a sequestration site below the plant. The Plains CO_2 RCSP is the largest of the regional partnerships and is working with the owner of the largest gas production plant in North America to inject 1.8 million tons of CO_2 into a deep saline sandstone formation in Northwest British Columbia. Another project involves injecting one million tpy of CO_2 into a carbonate saline formation over 10,000 feet below ground.

The Midwest Geologic Sequestration Consortium plans to inject one million tons of CO_2 at depths over 6,000 feet in the Mount Simon sandstone formation. The Midwest RCSP is planning a large volume CO_2 storage test, but a site has not been selected. The West Coast RCSP will inject one million tons of CO_2 more than 7,000 feet in the San Joaquin Basin in Central California below a 170 MW, zero emission power plant that uses natural or synthesis gas in an oxyfuel system that produces a relatively pure stream of CO_2. The Big Sky Carbon Sequestration Partnership will inject one million tpy of CO_2 into the Nugent Sandstone formation at depths of approximately 11,000 feet at Riley Ridge in Southwest Wyoming. These projects are designed to store CO_2 at a scale that is representative of a typical power plant.[449]

The Basin Electric Power Cooperative was selected for another demonstration project to begin in 2009 that will test CO_2 capture and storage using an ammonia solution in a post-combustion, regenerative process. The ammonia is recovered and reused, so there is no by-product created. CO_2 capture occurs after the nitrogen oxides, sulfur dioxide, mercury and fine particulates have been removed. The project is located at a 900 MW coal-fired electrical generating facility near Beulah, North Dakota and is expected to be operational in 2011.[450]

At this time there is no commercial-scale demonstrated technology for use at electric generating plants to capture and store CO_2.[451] NETL seeks to develop a portfolio of safe, cost-effective, commercial-scale GHG sequestration technologies. Its primary objectives are to reduce the cost and energy penalty of CO_2 capture and to improve storage permanence and safety of geological storage.[452] DOE has the major federal responsibility for developing carbon sequestration programs, but other government agencies are increasingly getting involved. Two EPA regional offices are participants in several of the regional partnerships and state regulatory agencies, and the companies in the private sector are among the participants. As the RCSP program matures, participation by other government agencies is expected to grow. DOE also is providing $126.6 million to conduct large-scale carbon capture

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[449] http://fossil.energy.gov/programs/sequestration/partnerships/ (last visited Dec. 3,, 2010).

[450] Basin Electric Power Cooperative Selects New Technology for Carbon Capture Demonstration, *available at* http://www.nreca.org/AboutUs/CooperativeDifference/20080414.htm (last visited Dec. 3, 2010).

[451] Lynn Garner, *Coal, Electricity Industries Ask White House To Double Funding for Carbon Technologies,* 39 Env't Rep. (BNA) 157 (Jan. 25, 2008).

[452] *See* http:www.netl.doe.gov/technologies/carbon_seq/index.html (last visited Dec. 3, 2010).

and sequestration tests in Ohio and California.[453] The Canadian government is planning to spend U.S. $114 million for eight CCS projects in western Canada.[454] On March 25, 2009, EPA approved a permit for a small carbon sequestration project in Arizona conducted by the West Coast Regional Carbon Sequestration Partnership (WESTCARB). EPA and Arizona's Department of Environmental Quality approved permits for a pilot sequestration project at the Arizona Public Service Company's Cholla Power Plant in Joseph City, AZ. This project is to study sequestration, but it is not intended to sequester CO_2.[455] Virginia Dominion Power is seeking federal money to capture CO_2 from its Virginia City Hybrid Energy Center that is now under construction, but environmental groups are litigating to prevent the plant from being completed.[456]

The Energy Independence and Security Act of 2007 requires the Department of Energy, the DOI, and EPA to establish programs to encourage CCS projects.[457] On October 3, 2008, the Emergency Economic Stabilization Act became law.[458] Section 115 provides a $20 tax credit for each ton of CO_2 that is sequestered. On May 15, 2009, DOE announced it would spend $2.4 billion to expand and accelerate commercial deployment of CCS technology, with the money coming from the 2009 American Recovery and Reinvestment Act (ARRA).[459] On June 10, 2010, DOE announced grants of as much as $612 million to support CCS projects at a new methanol plant, an oil refinery, and an ethanol plant.[460] On July 7, 2010, DOE announced grants totaling $51.7 million for CCS projects at electric power plants.[461]

§ 3(f). Financial Liability/Insurance

An issue in moving CCS projects forward is the long-term liability of those participating in such projects. Texas and Illinois addressed this problem by enacting legislation providing protection through indemnification.[462] But unless a broad indemnification program is created to limit the risk associated with unforeseen

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[453] Leora Falk, *Energy Department to Provide Funds For West Coast, Midwestern Projects,* 39 Env't Rep. (BNA) 898 (May 9, 2008).
[454] Peter Menyasz, *Canadian Agency Commits $114 Million For Eight Carbon Capture, Storage Projects,* 40 Env't Rep. (BNA) 761 (Apr. 3, 2009).
[455] *EPA Plan to Seek Comment on Sequestration Data May Delay CCS Rule,* XXVI ENVTL POL'Y ALERT (Inside EPA) 7:35 (Apr. 8, 2009).
[456] Jeff Day, *Virginia Tech, Dominion Seek Stimulus Funds For Carbon Capture Demonstration Project,* 40 Env't Rep. (BNA) 2056 (Aug. 28, 2009).
[457] 42 U.S.C. §16293.
[458] Pub. L. No. 110-343 (2008).
[459] Steven D. Cook, *Carbon Capture, Storage to Get $2.4 Billion In Recovery Funds, Secretary Chu Announces,* 40 Env't Rep. (BNA) 1164 (May 22, 2009).
[460] Steven D. Cook, *More Than $600 Million in Stimulus Grants Support Industrial Carbon Capture, Storage,* 41 Env't Rep. (BNA) 1356 (June 18, 2010).
[461] Steven D. Cook, *DOE Announces $51.7 Million to Fund Post-Combustion Carbon Capture Projects,* 41 Env't Rep. (BNA) 1515 (July 9, 2010). The projects include $14,756,199 to capture CO_2 at Arizona Public Services' Cholla Power Plant. *Id.*
[462] *California Struggles With Carbon Sequestration Policies,* ENVTL POL'Y ALERT (Inside EPA) 1:23 (Jan. 2, 2008).

environmental consequences from CCS, it is unlikely that major sequestration projects will proceed.

Because of the pressure exerted by the compressed CO_2 and the large quantities that will need to be sequestered, a release could have catastrophic consequences to the health of humans and animals downwind. Two issues that will need to be addressed are both short-term and long-term liability. In the short-term, industry will control injection sites. The operator would have primary responsibility for the life of the facility and a post-closure period. The time frequently mentioned for post-closure industry supervision is about 30 years.[463] After that the government would take responsibility for long-term monitoring and remediation if needed.

It should be noted that indemnification was a key element of the Price Anderson Act's insurance program associated with the nuclear industry, which has evolved into an industry-funded no-fault insurance program.[464] The number of industry participants allows for a manageable distribution of risk-related costs in the event of the worst-case event.[465] Such programs are not practical during the initial development of a technology wherein there exist few participants and a minimal economic base, thereby requiring indemnification by government to enable development investment to be made with definable down side risk to investors. Technology development implemented by corporations with substantial capital usually requires the avoidance of unlimited development-related risks that effectively place the company's net worth at risk as a necessary precondition to project approval and implementation. It has been suggested that a program similar to the Price-Anderson Act be enacted to cover both short-term and long-term liability.[466] Such a program would help make CCS facilities a more attractive investment for the private sector, but could reduce the incentive for avoiding risky behavior in the quest for profit maximization. The Price-Anderson Act, however, may not be a useful model. It applies to a well-capitalized industry with more than 100 units and provides financial protection for liability that may develop in a short time frame. Sequestration will initially involve a few units that may not have a significant cash flow and the potential liability will continue for a century or more.

In developing a financial liability program it will be important to do more than limit corporate financial exposure. It will be prudent to look more broadly at risk management issues to reduce risks associated with CCS. It is also important to

[463] However, the EPA set the time at 50 years, with some flexibility, in its final UIC Rule. UIC Rule, 75 Fed. Reg. at 77,300 (to be codified at 40 C.F.R. § 146.93).
[464] 42 U.S.C. § 2210 *et seq.*
[465] 42 U.S.C. § 2210.
[466] *EPA Finance Advisers Eye Price-Anderson Model For CCS Liability,* XXVI ENVTL POL'Y ALERT (Inside EPA) 6:39 (Mar. 25, 2009). The Price Anderson Act, 42 U.S.C. § 2210, requires each nuclear plant operator to obtain up to $300 million in primary insurance. A secondary insurance program provides for up to $95.8 million per unit to be paid in annual installment. Thereafter, the federal government assumes any remaining liability.

assure that the interests of the public, state and local governments, and investors are protected when an accident occurs. A financial protection program could utilize a mix of performance bonds, insurance, surety instruments, and other financial instruments in order to protect those that may be harmed by CCS. Performance bonds have long been used to assure reclamation of mined lands and for injection wells under the UIC program, but they can be expensive for small businesses. Bond premiums are often 1% to 5% of the face value, but small firms may have premiums of 15% to 25%.[467] Bonds to be effective need to have a specified time for coverage, an identified responsible party, and an amount sufficient to monitor, verify, and remediate damages. However, bonds may not be as effective with a sequestration program because the inherent long time-frame for post-closure would result in costly bonds and would make insurance a more attractive alternative approach.[468] However, private insurers may be reluctant to insure risks that are largely unknown and may be difficult to quantify.

A useful model for handling CCS liability could be the Trans-Alaska Pipeline Liability Fund (TAPL)[469], which has been integrated into the funding available under the Oil Pollution Act (OPA).[470] If an incident occurs on water, TAPL provides for up to $14 million being paid quickly based on strict liability principles. Any amount not covered by TAPL may be sought from ship operators, up to $100 million per incident, based on federal or state law.[471] As an alternative approach, a compensation fund could be provided by the government with the costs to be assumed by taxpayers.

The Southern Company, Duke Energy, the Environmental Defense Fund and the Zurich Insurance Company have developed an insurance plan that they are urging Congress to codify. It calls for a four tiered liability program for CCS operations. Under the first tier CCS operators would be liable for $50 million or more as determined by Congress. The second tier would be an industry-wide pool that would have a liability of $12.5 million per entity that would become a substantial additional source of coverage as CCS operations grow. The third tier would consist of a government funded insurance program that would have a lifetime cap of $300 million to $900 million per operator. The fourth tier would require the operator to cover any liabilities that exceeded the first three tiers of coverage.[472] The American Power Act, discussed in § 4(d) *infra,* does not address CCS liability. Senate Bill 1462, the American Clean Energy Leadership Act of 2009 (ACELA), sponsored by Senator Jeff Bingman (D-NM), discussed in § 4(b) *infra,* covers indemnification and S. 3590 and S. 3591 sponsored by Senators Jay Rockefeller (D-

[467] Klass & Wilson, *supra* note 330, at 161.
[468] *Id.* at 162.
[469] 14 U.S.C. § 1653.
[470] Oil Pollution Act §§ 1001 to 7002, 33 U.S.C. §§ 2701 to 2761.
[471] 43 U.S.C. § 1653(c)(1).
[472] Kate Williams, *Coalition Offers Deal On CCS Liability For Future Climate Change Bill,* XXI CLEAN AIR REP. (Inside EPA) 16:27 (Aug. 5, 2010).

W.Va.) and George Voinovich (R-Ohio, discussed in § 4(e) *infra,* would create a fund paid for by utilities to cover potential CCS liability.

§ 4. Federal Legislative Proposals

On March 24, 2009, Rep. Boucher introduced his latest version of the Carbon Capture and Storage Early Deployment Act (H.R. 1689). The bill would raise $10 billion over the next ten years by taxing fossil fuel generated electric power.[473] On April 2, 2009, the Senate authorized a new fund to accelerate commercial-scale deployment of CCS.[474] On May 21, 2009, Senator Robert Casey (D-Pa.) introduced S. 1134, the Responsible Use of Coal Act, to provide for research, development and deployment of CCS technology. [475] On May 7, 2009, Senate Energy and Natural Resources Chairman Jeff Bingaman (D-N.M.) introduced the Department of Energy Carbon Capture and Sequestration Program Amendments Act of 2009 (S. 1013) that would authorize $100 million over ten years to establish a program to support up to ten commercial-scale CCS projects that would store more than 1 million tons of carbon dioxide emissions a year.[476] Other CCS bills introduced in the 110th Congress include S.962 and H.R. 931 that deal with technology development and include provisions promoting separation and capture of CO_2 and S.731 and H.R. 1267 that call for the expansion of the nation's capacity for long-term CO_2 storage in geologic reservoirs. Most of the legislative efforts of the Congress, however, have been directed at passing cap-and-trade legislation, and each of these bills have provisions dealing with CCS.

§ 4(a). The American Clean Energy and Security Act of 2009 (H.R. 2454)

The House Committee on Energy and Commerce reported H.R. 2454, the American Clean Energy and Security Act of 2009 (ACES) on May 21, 2009.[477] The bill, also known as the Waxman-Markey bill was introduced May 15, 2009 "to create clean energy jobs, achieve energy independence, reduce global warming pollution and transition to a clean energy economy."[478] On June 26, 2009, the House approved

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[473] Dean Scott, *Boucher Introduces Revised Legislation For $1 Billion Annual Carbon Capture Fund,* 40 Env't Rep. (BNA) 681 (Mar. 27, 2009).
[474] Dean Scott, *Senate Paves Way for Carbon Capture Fund, Raises Bar for Passage of Cap-and-Trade,* 40 Env't Rep. (BNA) 807 (Apr. 10, 2009).
[475] Steven D. Cook, *Casey Bill Would Accelerate Deployment Of Carbon Capture, Storage Technology,* 40 Env't Rep. (BNA) 1241 (May 29, 2009).
[476] Ari Natter, *Senate Bill Would Authorize $100 Million For 'Large-Scale' Carbon-Capture Projects,* 40 Env't Rep. (BNA) 1108 (May 15, 2009).
[477] PEW Center on Global Climate Change, The American Clean Energy and Security Act (Waxman-Markey Bill), available at http://www.pewclimate.org/acesa (last visited Mar. 5, 2010).
[478] American Clean Energy and Security Act of 2009, House of Rep., 11th Cong., 1st Sess., Rept. 111-137, Pt. 1, at 277.

the H.R. 2454 by a vote of 219 to 212. Eight Republicans voted for the bill, but 44 Democrats did not.[479] The debate then moved to the Senate.

Much of the ACES legislation deals with its cap-and-trade program.[480] This bill allows GHG emitters to avoid emission reductions if they hold enough allowances. Emissions in excess of the covered entities emissions allowances are prohibited, and penalties for violation are provided.[481] Once an allowance is obtained it can be used or traded or banked, which makes them a valuable asset that the federal government is giving away or selling in order to fund a variety of programs.[482] The legislation provides for 70.4% of the allowances to be freely allocated in 2012 and this will increase to 82.5% in 2019.[483] The remaining 29.6% to 17.5% of the allowances are to be auctioned.[484] The Committee of Energy and Commerce estimated the total value of allowances created by H.R. 2454 would range from $60 billion in 2012 to $113 billion in 2025, which is an approximate annual average value during that time span of $82.5 billion.[485] About 13.8% of the value of the allowances is to be used to invest in clean energy technologies of which 2.6% will go for CCS programs. About 73.4% of the allowances will be used to fund assistance to energy consumers and industry, of which 14.8% will be given those with low-incomes. [486]

Title III of ACEs, which includes the cap-and-trade program, creates a new CAA Title VII. CAA § 700 (13) defines "covered entity" to include any geologic sequestration site. CAA § 700(1) and (2) define "additional" and "additionality" for purposes of the offset program to include sequestration of GHGs. CAA § 700 (26) and (27) define "geologic sequestration" and "geologic sequestration site" as a site where GHGs are sequestered in a subsurface geologic formation for purposes of permanent storage. CAA § 700 (35) defines "mineral sequestration" as "sequestration of carbon dioxide from the atmosphere by capturing carbon dioxide into a permanent mineral, such as the aqueous precipitation of carbonic minerals that results in the storage of carbon dioxide in a mineral form." CAA § 700(45) defines sequestered and sequestration to "mean the separation, isolation, or removal of greenhouse gases from the atmosphere, as determined by the

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[479] Richard G. Stoll, *House Global Climate Bill Mandates Many EPA Rulemakings With Tight Deadlines,* 40 Env't Rep. (BNA) 1672 (July 10, 2009).
[480] For a review of H.R.2454's cap and trade program see Tom Mounteer, *Comprehensive Federal Legislation to Regulate Greenhouse Gas Emissions,* 39 Envtl L. Rep. (ELI) 11068 (Nov. 2009).
[481] ACES § 311, which creates CAA Title VII, Part C, §§ 722-723.
[482] *Id.* at CAA §§ 724-725.
[483] Congressional Budget Office Cost Estimate, H.R. 2454, American Clean Energy and Security Act of 2009, 6 (June 5, 2009) (hereinafter CBO).
[484] ACES § 321, which creates CAA § 781.
[485] House Committee on Energy and Commerce, American Energy and Security Act (H.R. 2454) 4 (June 2, 2009), available at
<http://energycommerce.house.gov/Press_111/20090602/hr2454_reported_summary.pdf> (last visited Apr. 6, 2010).
[486] Breakthrough Institute, Kerry-Boxer Climate Bill Allowance Allocation Breakdown, available at http://the breakthrough.org/blog/2009/10/kerryboxer_climate_bill_allowa.shtml (last visited Dec. 4, 2010).

Administrator. The terms include biological, geologic, and mineral sequestration, but do not include ocean fertilization techniques."

Title I, Subtitle B addresses CCS. [487] ACES § 111 gives the Administrator one year after the date of enactment to identify the key legal, regulatory and other barriers to CCS and to inform Congress what additional federal legislation is needed. AECS § 112 amends Title VIII of the CAA (which is added by H.R. 2454, § 331) to require the Administrator to establish a coordinated approach to certifying and permitting geologic sequestration taking into account the requirements of the SDWA.[488]

ACES § 112(b) requires EPA to promulgate regulations to protect human health and the environment by minimizing the risk of CO_2 escaping from geologic sequestration within two years of enactment of this title. Within one year after enactment, section 112(e) requires regulations to be promulgated for carbon dioxide geological sequestration wells. These regulations "shall include requirements for maintaining evidence of financial responsibility, including financial responsibility for emergency and remedial response, well plugging, site closure, and post-injection site care." Financial responsibility may be established in accordance with regulations by: "insurance, guarantee, trust, standby trust, surety bond, letter of credit, qualification as a self-insurer, or any other method satisfactory to the Administrator." Section 113 calls for additional studies and reports.

ACES § 114(b) provides for the creation of a Carbon Storage Research Corporation. Formation of the corporation would occur if a referendum among the electric generating industry approved, but once approved it would be subject to considerable federal control although it would not be a government agency. Pursuant to section 114(d), the corporation would levy annual assessments based on the amount of fossil fuel-based electricity delivered to retail customers, but the assessment would vary depending on the fuel used to generate electricity with coal being assessed at almost twice the charge per kilowatt hour of natural gas. It would generate between $1 billion and $1.1 billion a year that would be used to accelerate the commercial availability of CCS. Fifty percent of the funds are to be provided to electric utilities that have committed resources to CCS.

ACES § 115 amends CAA Title VII (added by ACES § 311) to add CAA § 786 that requires EPA to promulgate regulations within two years after H.R. 2454 is enacted to provide for the distribution of emission allowances to support commercial deployment of CCS technologies.

ACES § 116 requires new coal-burning power plants permitted after 2020 to use CCS when they commence operations. Plants permitted between 2015 and 2020 lose eligibility for federal financial assistance if they do not use CCS when they

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[487] ACES §§ 111-116.
[488] SDWA § 1421, 42 U.S.C. § 300h

commence operations. Such plants must retrofit CCS by 2025. Coal plants permitted between 2009 and 2015 lose eligibility for federal financial assistance if they do not retrofit CCS within five years after commencing operations, after which they must retrofit by 2025 without federal financial assistance. The 2025 retrofit requirement is accelerated if four gigawatts of electricity generation is utilizing CCS before 2025, but on a case-by-case basis compliance may be extended by EPA for up to eighteen months.[489] This acceleration provision does not allow adequate experience with the technology to demonstrate it is cost effective and safe.

Title III of ACES also deals with sequestration as part of its offset program that it creates in a new CAA Title VII, §§ 731-743. CAA § 731(c)(2) requires the Administrator to establish an "Offsets Integrity Advisory Board" to provide advice and comments on methodologies to "address the issues of additionality, activity baselines, measurement, leakage, uncertainty, permanence, and environmental integrity" of offset projects. CAA § 732 gives EPA two years to promulgate regulations that include provisions to assure offset credits for sequestration that are only issued for GHG reductions that are permanent. CAA § 734 specifies requirements for offset projects that include "additionality" requirements to prevent sequestration from receiving offset credit unless it is not required by "any law, including any regulation or consent order." This would appear to remove most sequestration projects from being used for offsets. CAA § 734(b) includes provisions to deal with offset projects involving a sequestration reversal or failure. Section 734(b) (3)(B)(iii) deals with unintentional reversals, but it is not clear what time period is to be used to determine whether a reversal has occurred. CAA § 735 deals with approval of offset projects, and CAA § 735(f) authorizes EPA to develop a preapproval review process. CAA § 736 requires EPA to develop a verification process for offset projects, including sequestration projects, that includes third party verification.

§ 4(b). The American Clean Energy Leadership Act of 2009 (S. 1462)

The Senate Committee of Energy and Natural Resources (ENR Committee) focused on S. 1462, the American Clean Energy Leadership Act of 2009 (ACELA), sponsored by Senator Jeff Bingman (D-NM).[490] On June 17, 2009 the committee voted 15 to 8 to report ACELA, which was placed on the Senate's legislative calendar on July 16, 2009. It indirectly reduces GHG emissions by encouraging efficient, alternative, and low carbon energy production and use. ACELA achieves these goals by amending and supplementing previous energy bills. It is a comprehensive

[489] American Energy and Security Act (H.R. 2454) § 115(June 2, 2009), available at http://energycommerce.house.gov/Press_111/200906701/hr2454_house.pdf (last visited Mar. 5, 2010).

[490] Senate Committee on Energy and Natural Resources Legislative Calendar, http://energy.senate.gov/public/index.cfm?FuseAction=Legislation.ViewByBillType&Type_ID=07f15fd7-6014-478c-ab8b-fa78441de9d0&Congress_ID=111 (last visited Dec. 4, 2010).

approach to reducing energy use while encouraging development of domestic sources of oil and natural gas. It provides funding for demonstrating large-scale geologic storage of industrial sources of carbon dioxide.[491] Its most striking feature is that it does not include a cap-and-trade program.

S. 1462 creates a Clean Energy Deployment Administration to facilitate new financing of tens of billions of dollars to achieve breakthroughs in the deployment of clean energy technologies. It also requires electric utilities to meet fifteen percent of their electricity sales by 2021 using renewable energy. It requires the establishment of a national electrical energy transmission grid.

> ACELA in Title I establishes a Clean Energy Development Administration ("the administration") that may "issue direct loans, letters of credit, loan guarantees, insurance products, or such other credit enhancements (including through participation as a co-lender or a lending member of a syndication) as the Administrator considers appropriate to deploy clean energy technologies if the Administrator has determined that deployment of the technologies would benefit or be accelerated by the support."[492] Clean energy is defined to include efforts that contribute to a stabilization of atmospheric greenhouse gas concentrations through reduction, avoidance, or sequestration of energy-related emissions.[493]

ACELA establishes the Clean Energy Investment Fund ("the Fund"), a revolving fund created to carry out the administrative functions of Title XVII, Incentives for Innovative Technologies, of the Energy Policy Act of 2005 ("2005 Act").[494] Under Title XVII of the 2005 Act, the Secretary may make loan guarantees for up to eighty percent of the cost of projects[495] that "avoid, reduce, or sequester air pollutants or anthropogenic emissions of greenhouse gasses and employ new or significantly imported technologies as compared to commercial technologies in service in the United States at the time in the guarantee is issued."[496] The money for

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[491] Senate Report 111-048, at 111 (2009) *also available at* http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=111_cong_reports&docid=f:sr048.111.pdf or http://thomas.loc.gov/cgi-bin/cpquery/?&dbname=cp111&sid=cp111nrwv6&refer=&r_n=sr048.111&item=&sel=TOC_3251& (last visited Dec. 4, 2010).

[492] The American Clean Energy Leadership Act of 2009, S. 1462, 111th Cong. §106(a)(1)(A)(2009). *See also* §1(a)(2) regarding Congressional mandate to provide "indirect support" to help develop and mobilize private financial support and investment for developing and aggregating small clean energy projects. S.1462, 111th Cong. §106(a)(2)(2009).

[493] S.1462, 111th Cong. § 102(5) (2009).

[494] The American Clean Energy Leadership Act of 2009, S. 1462, 111th Cong. § 103(a)(2009). The Energy Policy Act of 2005, 42 USC § 16511 et. seq. (2005).

[495] 42 USC § 16512(c). *See also* S. 1462, 111th Cong. §104(b)(amending 42 USC § 16512, which details the requirements for a government loan).

[496] 42 USC § 16513(a). *See also* 42 USC § 16513(b)(listing eligible projects as; 1) Renewable energy systems; 2) Advanced fossil energy technology (including coal gasification meeting the criteria in subsection (d) of this section); 3) Hydrogen fuel cell technology for residential, industrial, or

the ACELA Fund is the amount authorized in the Energy Policy Act of 2005,[497] plus new funds provided for under ACELA, and any other funds appropriated to supplement the fund.[498]

ACELA's carbon capture program incorporates the existing provisions found in the Energy Policy Act of 2005. The goal of § 963 of the 2005 Act is to create "a 10-year carbon capture and sequestration research, development, and demonstration program to develop carbon dioxide capture and sequestration technologies related to industrial sources of carbon dioxide for use in new coal utilization facilities and on the fleet of coal-based units in existence on August 8, 2005."[499]

The 2005 Act enumerates five key objectives to fulfill the goals of the program. They are 1) to develop technologies for CO_2 capture including techniques and chemical processes for adsorption and absorption and the removal of CO_2 from gas streams;[500] 2) develop technologies to produce streams of concentrated CO_2 for sequestration;[501] 3) increase efficiency of power producing systems to reduce CO_2 emissions per megawatt generated;[502] 4) promote a robust carbon sequestration program through continued work in the Department of Energy and the private sector through regional sequestration partnerships;[503] and 5) advance large-scale carbon sequestration testing projects in a variety of geologic formations to provide cost and feasibility information for deployment of the technology.[504]

The 2005 Act lists 6 actions needed to realize these objectives. First, research and development and demonstration is needed to support carbon capture and sequestration technologies and carbon use activities.[505] This research and development includes laboratory scale experiments, modeling, and simulations[506] that are integrated into and applied to energy technology development activities.[507] Second, there needs to be field validation testing and "geologic sequestration tests involving carbon dioxide injection and monitoring, mitigation, and verification

transportation applications; 4) Advanced nuclear energy facilities; 5) Carbon capture and sequestration practices and technologies, including agricultural and forestry practices that store and sequester carbon; 6) Efficient electrical generation, transmission, and distribution technologies; 7) Efficient end-use energy technologies; 8) Production facilities for the manufacture of fuel efficient vehicles or parts of those vehicles, including electric drive vehicles and advanced diesel vehicles; 9) Pollution control equipment; and 10) Refineries, meaning facilities at which crude oil is refined into gasoline.

497 S. 1462, 111th Cong. § 103(a)(1)(B)

498 S. 1462, 111th Cong. §103(a)(1).

499 42 U.S.C. § 16293(a) (2005).

500 42 U.S.C § 16293(b)(1) (2005).

501 42 U.S.C § 16293(b)(2) (2005).

502 42 U.S.C § 16293(b)(3) (2005).

503 42 U.S.C § 16293(b)(4) (2005).

504 42 U.S.C § 16293(b)(5) (2005).

505 42 U.S.C § 16293(c)(1)(2005).

506 42 U.S.C § 16293(c)(1)(A)(2005).

507 42 U.S.C § 16293(c)(1)(B)(2005). *See* 42 U.S.C § 16293(c)(1)(B)(i)-(vi)(2005) for specific types of activities or technologies the research is to be applied.

operations in a variety of candidate geologic settings."[508] Third, the 2005 Act mandates large-scale carbon dioxide sequestration testing including no less than seven projects, not including the FutureGen facility, in a variety of geologic formations to "collect and validate information on the cost and feasibility of commercial deployment of technologies for geologic containment of carbon dioxide."[509] Fourth, projects submitting competitive applications for government assistance will be given preference for demonstrating partnerships among industrial, academic, and government entities and ensuring laborers are paid a competitive wage.[510] Fifth and sixth, potential projects and research and development activities must comply with cost sharing requirements,[511] and during 2011 the Secretary shall conduct a review and give recommendations for continuance of the projects.[512] The 2005 Act authorizes to be appropriated $240 million per fiscal year from 2008 through 2012 for the program.[513]

In addition to the incorporating the above criteria found in the 2005 Act, ACELA adds a new Section, 963A, to the 2005 Act.[514] This new section of ACELA mandates, "the Secretary shall carry out a program to demonstrate the commercial application of integrated systems for the capture, injection, monitoring, and long-term geological storage of carbon dioxide from industrial sources."[515]

The Secretary of Energy may enter into cooperative agreements for financial and technical aid for up to ten demonstration projects.[516] Selection will be competitively based on project applications.[517] Applicants must provide information demonstrating the site is geologically suitable for long-term CO_2 storage by including information regarding; the location, extent, and storage capacity of the geological storage unit at the site into which the carbon dioxide will be injected; the principal potential modes of geomechanical failure in the geological storage unit; the

508 42 U.S.C § 16293(c)(2)(A)(2005). *See* 42 U.S.C § 16293(c)(2)(A)(i)-(vi)(2005) for specific types of geologic formations where testing should occur.

509 42 U.S.C § 16293(c)(3)(A)(2005). *See* 42 U.S.C § 16293(c)(3)(B)(2005) for specific types of geologic formations where testing should occur.

510 42 U.S.C § 16293(c)(4)(2005).

511 42 U.S.C § 16293(c)(5)(2005). The cost sharing requirements under the 2005 Act are as follows:
(1) In general :Except as provided in paragraphs (2) and (3) and subsection (f) of this section, the Secretary shall require not less than 20 percent of the cost of a research or development activity described in subsection (a) of this section to be provided by a non-Federal source.
(2) Exclusion: Paragraph (1) shall not apply to a research or development activity described in subsection (a) of this section that is of a basic or fundamental nature, as determined by the appropriate officer of the Department.
(3) Reduction" The Secretary may reduce or eliminate the requirement of paragraph (1) for a research and development activity of an applied nature if the Secretary determines that the reduction is necessary and appropriate. 42 U.S.C § 16352(b)(2005).

512 42 U.S.C § 16293(c)(6)(2005).

513 42 U.S.C § 16293(d)(2005).

514 S. 1462, 111th Cong. § 371 (2009).

515 S. 1462, 111th Cong. § 371(a)(2009)(adding 42 U.S.C. § 16293A(b))

516 S. 1462, 111th Cong. § 371(a)(2009) (adding 42 U.S.C.§ 16293A(c)).

517 S. 1462, 111th Cong. § 371(a)(2009) (adding 42 U.S.C. § 16293A(d)).

ability of the geological storage unit to retain injected carbon dioxide; and the measurement, monitoring, and verification requirements necessary to ensure adequate information on the operation of the geological storage unit during and after the injection of CO_2.[518] Applicants must possess the land or interest in land that is necessary for the injection and storage of carbon and have a plan to assure long-term closure, monitoring, and stewardship of the site.[519] Similarly the applicants must have or reasonably expect to obtain the necessary federal and state permits[520] and must agree to comply with the terms and conditions of the ACELA.

For a carbon capture project under ACELA to obtain government assistance it must:

1. comply with all applicable federal and state laws (including regulations), including a certification by the appropriate regulatory authority that the project will comply with federal and state requirements to protect drinking water supplies;
2. inject only CO_2 captured from industrial sources in compliance with the Clean Air Act,[521] if the sources are subject to the CAA;
3. comply with all applicable construction and operating requirements for deep injection wells;
4. verify that CO_2 injected into the injection zone is not (A) escaping from or migrating beyond the confinement zone; or (B) endangering an underground source of drinking water by measuring, monitoring and testing;
5. comply with applicable well-plugging, post-injection site care, and site closure requirements, including maintaining financial assurances during the post-injection closure and monitoring phase until a certificate of closure is issued by the Secretary; and promptly undertaking remediation activities for any leak from the geological storage unit that would endanger public health or safety or natural resources; comply with subsection (f)[detailed below];
6. comply with applicable long-term care requirements;
7. maintain financial protection in a form and in an amount acceptable to the Secretary of DOE, the Secretary with jurisdiction over the land, and the Administrator of EPA; and
8. provide the assurances concerning labor standards described in section 963(c)(4)(B).[522]

Subsection (f) enumerates the post injection closure and monitoring elements required for government assisted carbon capture projects. To be in compliance with subsection (e)(5), listed above, a project shall demonstrate compliance with each of the following

[518] S. 1462, 111th Cong. § 371(a)(2009) (adding 42 U.S.C. § 16293A(d)(1)).
[519] S. 1462, 111th Cong. § 371(a)(2009) (adding 42 U.S.C. § 16293A(d)(2)).
[520] S. 1462, 111th Cong. § 371(a)(2009) (adding 42 U.S.C. § 16293A(d)(3)(4)).
[521] 42 U.S.C. § 7401 *et seq.*
[522] S. 1462, 111th Cong. § 371(a)(2009) (adding 42 U.S.C. § 16293A(e)(1)-(8)).

elements for a period of not less than ten years after the injected CO_2 has stabilized.[523] The required components are: 1) the size and extent of the project's estimated footprint has not substantially changed and is contained within the geologic unit; 2) the formation pressure has not increased after injection of CO_2 into the formation has stopped; 3) there is no CO_2 leakage or displaced formation fluid that endangers public health and safety, including underground sources of drinking water and natural resources; 4) injected or displaced formation fluids are not anticipated to migrate towards a potential leakage pathway; and 5) injection wells are plugged and abandoned in accordance with applicable federal and state law.[524]

The final three ACELA amendments to the Energy Act of 2005 regarding carbon capture address indemnification agreements, title to lands for long term monitoring, and federal lands. ACELA's indemnity agreements requires that "[n]o later than 1 year after the date of the receipt . . . [of a] completed application for a demonstration project, the Secretary may agree to indemnify and hold harmless the recipient of a cooperative agreement under this section from liability arising out of or resulting from a demonstration project in excess of the amount of liability covered by financial protection maintained by the recipient. . . ."[525] ACELA indemnity agreements must also include exceptions for gross negligence and intentional misconduct, ACELA's statutorily enumerated fee schedule, and ACELA's statutory conditions for the agreements.[526]

For carbon capture on federal land the Secretary concerned [either the Secretary of the Interior or Agriculture][527] may authorize the siting of a project on federal land under the jurisdiction of the Secretary concerned in a manner consistent with applicable laws and land management plans and subject to such terms and conditions as the Secretary concerned determines to be necessary. In determining whether to authorize a project on federal land, the Secretary concerned shall take into account the framework for geological carbon sequestration on public land prepared in accordance with section 714 of the Energy Independence and Security Act of 2007 (Public Law 110-140; 121 Stat. 1715).[528]

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[523] S. 1462, 111th Cong. § 371(a)(2009) (adding 42 U.S.C. § 16293A(f)).
[524] S. 1462, 111th Cong. § 371(a)(2009) (adding 42 U.S.C. § 16293A(f)(1)-(5)).
[525] S. 1462, 111th Cong. § 371(a)(2009) (adding 42 U.S.C. § 16293A(g)(2)).
[526] S. 1462, 111th Cong. § 371(a)(2009) (adding 42 U.S.C. § 16293A(g)(3)-(6)).
[527] S. 1462, 111th Cong. § 371(a)(2009) (adding 42 U.S.C. § 16293A(a)(3)).
[528] S. 1462, 111th Cong. § 371(a)(2009) (adding 42 U.S.C. § 16293A(h)). Section 714 of the Energy Independence and Security Act of 2007 requires:
(a) Report- Not later than 1 year after the date of enactment of this Act, the Secretary of the Interior shall submit to the Committee on Natural Resources of the House of Representatives and the Committee on Energy and Natural Resources of the Senate a report on a recommended framework for managing geological carbon sequestration activities on public land.
(b) Contents- The report required by subsection (a) shall include the following:
(1) Recommended criteria for identifying candidate geological sequestration sites in each of the following types of geological settings: (A) Operating oil and gas fields; (B) Depleted oil and gas fields; (C) Unmineable coal seams; (D) Deep saline formations; (E) Deep geological systems that may be used as engineered reservoirs to extract economical quantities of heat from geothermal resources of low permeability or porosity; (F) Deep geological systems containing basalt formations; (G) Coalbeds

ACELA amends the 2005 Act by permitting "the Secretary [to] accept title to, or transfer of administrative jurisdiction from another federal agency over, any land or interest in land necessary for the monitoring, remediation, or long-term stewardship of a project site."[529] The goal of accepting or transferring title is to "ensure the sure the geologic integrity of the site and prevent any endangerment of public health or safety."[530]

In addition to the 2005 Act amendments, ACELA includes a new provision creating a program to distribute grants to State agencies for training programs related to permitting, management, inspection, and over oversight of carbon capture, transportation, and storage projects.[531] ACELA authorizes $10,000,000 a year from 2010 through 2020 for this training program.[532]

§ 4(c). The Clean Energy Jobs and American Power Act (S. 1733)

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being used for methane recovery. (2) A proposed regulatory framework for the leasing public land or an interest in public land for the long-term geological sequestration of carbon dioxide, which includes an assessment of options to ensure that the United States receives fair market value for the use of public land or an interest in public land for geological sequestration.
(3) A proposed procedure for ensuring that any geological carbon sequestration activities on public land-- (A) provide for public review and comment from all interested persons; and (B) protect the quality of natural and cultural resources of the public land overlaying a geological sequestration site.(4) A description of the status of Federal leasehold or Federal mineral estate liability issues related to the geological subsurface trespass of or caused by carbon dioxide stored in public land, including any relevant experience from enhanced oil recovery using carbon dioxide on public land.(5) Recommendations for additional legislation that may be required to ensure that public land management and leasing laws are adequate to accommodate the long-term geological sequestration of carbon dioxide.(6) An identification of the legal and regulatory issues specific to carbon dioxide sequestration on land in cases in which title to mineral resources is held by the United States but title to the surface estate is not held by the United States. (7)(A) An identification of the issues specific to the issuance of pipeline rights-of-way on public land under the Mineral Leasing Act (30 U.S.C. 181 et seq.) or the Federal Land Policy and Management Act of 1976 (43 U.S.C. 1701 et seq.) for natural or anthropogenic carbon dioxide. (B) Recommendations for additional legislation that may be required to clarify the appropriate framework for issuing rights-of -way for carbon dioxide pipelines on public land.
(c) Consultation With Other Agencies- In preparing the report under this section, the Secretary of the Interior shall coordinate with-- (1) the Administrator of the Environmental Protection Agency; (2) the Secretary of Energy; and (3) the heads of other appropriate agencies.
(d) Compliance With Safe Drinking Water Act- The Secretary shall ensure that all recommendations developed under this section are in compliance with all Federal environmental laws, including the Safe Drinking Water Act (42 U.S.C. 300f et seq.) and regulations under that Act.

[529] S. 1462, 111th Cong. § 371(a)(2009) (adding 42 U.S.C. § 16293A(i)(1) (2005)).
[530] S. 1462, 111th Cong. § 371(a)(2009) (adding 42 U.S.C. § 16293A(i)(2) (2005)).
[531] S. 1462, 111th Cong. § 372(a)(2009).
[532] S. 1462, 111th Cong. § 371(b)(2009).

The Senate Environment and Public Works Committee Chair Barbara Boxer (D-CA) and Senator John Kerry (D-Mass.) on September 30, 2009, introduced the Clean Energy Jobs and American Power Act (S.1733). On November 5, 2009, a modified S. 1733 was reported out of the Environment and Public Works Committee by a vote of 11-1, with only Senator Max Baucus (D-Mont.) voting against the bill. None of the seven Republicans on the committee voted on the bill.[533] S.1733 is opposed by most Republican Senators because of the bill's cost, its cap-and-trade program, and its failure to provide a major impetus for nuclear power development.[534]

The heart of both H.R. 2454 and S. 1733 is the cap-and-trade program. Both bills specify how allowances will be allocated with most of the allocations being politically driven payoffs to pressure groups whose support is needed to have the legislation enacted. Because cap-and-trade legislation will increase the cost of energy, an issue that should be addressed is the treatment of imported goods from countries with less stringent GHG requirements. If sequestration requirements imposed by the United States are to avoid adversely affecting the economy an appropriate treatment of foreign produced products in countries without sequestration requirements will be needed that does not violate international trade agreements. Both H.R. 2454 and S. 1733 provide free allowances for trade-vulnerable industries that are valued at over a billion dollars during 2012-2021.[535] Cap-and-trade costs, including those associated with sequestration, that affect the competitiveness of U.S. business are not addressed in the legislation.

Title I, Subtitle B of S. 1733, deals with carbon capture and sequestration.[536] The Senate seeks to provide more incentives for CCS that the House bill. The House bill provides incentives for plants that use CCS for the first six gigawatts of power to come online, but some senators are seeking benefits for the first twenty gigawatts to achieve widespread commercial deployment of CCS by 2030. [537]

S.1733 establishes a "national strategy" for carbon sequestration.[538] The Administrator of EPA, in consultation with the Secretary of Energy, the Secretary of

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533 Press Release, Majority Page, Senate Environment and Public Works Committee, Boxer Statement on Committee Passage of S. 1733 – The Clean Energy Jobs and American Power Act (November 5, 2009) *available at* http://www.epw.senate.gov/public/index.cfm?FuseAction=Majority.PressReleases&ContentRecord_id=c512ac4d-802a-23ad-4884-2b95a8405efe (last visited Dec. 4, 2010).

534 Dean Scott, *Senate Environment Committee Passes Bill To Cap Emissions; Republicans Boycott Vote,* 40 Env't Rep. (BNA) 2552 (Nov. 6, 2009); Leora Falk, *Bill Maintains Emissions Cuts, EPA Authority, Leaves Negotiating Room for Senate Debate,* 40 Env't Rep. (BNA) 2282 (Oct. 2, 2009).

535 Breakthrough Institute, *supra* note 491.

536 S. 1733, 111th Cong. § 121 et seq. (2009).

537 Dean Scott, *Eight Senators Seek Boost in Incentives For Coal Plant Carbon Capture in Senate Bill,* 40 Env't Rep. (BNA) 2179 (Sept. 18, 2009). The senators are Robert Byrd (D-W.Va.), Bob Casey (D-Pa.), Joseph Lieberman (I/D-Conn.), Mark Warner (D-Va.), Tom Carper (D-Del.), Max Bacus (D-Mont.), Arlen Spector (D-Pa.), and Amy Klobuchar (D. Minn.).

538 S. 1733, 111th Cong. § 121 (c) (2009).

the Interior, and the heads of other relevant federal agencies the President may designate, must submit a report to Congress that includes a comprehensive strategy to identify the regulatory, legal and other barriers to the commercial-scale deployment of carbon capture and storage not later than one year after enactment of this Act.[539] The report is to address how these barriers could be overcome through existing federal statutory authority, new federal legislation, if needed, or State, tribal, or regional efforts.[540]

The Kerry-Boxer Bill would add a new Title VIII to the CAA. CAA § 813 would create a Coordinated Certification and Permitting Process, administered by EPA, to coordinate the certifying and permitting of geologic storage sites.[541] This coordinated process is to reduce the burden on implementing authorities by taking into account and reducing redundancies with other federal statutes and initiatives including the SDWA[542] and the proposed "Federal Requirements Under the Underground Injection Control Program for Carbon Dioxide Geological Sequestration Wells."[543] Within two years of passage of S. 1733, the Administrator is to promulgate regulations to protect human health and environment by minimizing the risk of escaped CO_2.[544] These regulations are to include a certification process and requirements for: monitoring, recordkeeping, and reporting of emissions associated with injection into, and escape from, geological storage sites, taking into account any requirements or protocols developed under CAA § 713; public participation in the certification process that maximizes transparency; sharing of data among States, Indian tribes, and EPA; and any other safeguards necessary to achieve the purpose of the regulation.[545]

Two years after promulgating rules, and not less than once every three years afterwards, the Administrator is to submit[546] a report on the state of geologic storage in the United States and, where relevant, other countries in North America.[547] This report is to include:

> (A) data regarding injection, emissions to the atmosphere, if any, and performance of active and closed geological storage sites, including those at which enhanced hydrocarbon recovery operations occur;
> (B) an evaluation of the performance of relevant federal environmental regulations and programs in ensuring environmentally protective geological storage practices; and

[539] S. 1733, 111th Cong. § 121(a) (2009).
[540] S. 1733, 111th Cong. § 121(b) (2009).
[541] S. 1733, 111th Cong. § 122 (2009)(adding CAA § 813).
[542] 42 U.S.C § 300h.
[543] 73 Fed. Reg. 43,492 (July 25, 2008). SB 1733, 111th Cong. § 122(a) (2009)(adding § 813 (a)(1)(2)).
[544] S. 1733, 111th Cong. § 122 (2009)(adding CAA § 813(b)).
[545] S. 1733, 111th Cong. § 122(a) (2009)(adding CAA § 813 (c)(1)-(2)).
[546] This report shall be submitted to the Committee on Energy and Commerce of the House of Representatives and the Committee on Environment and Public Works of the Senate. S. 1733, 111th Cong. § 122(a) (2009)(adding CAA § 813 (d)(1)).
[547] S. 1733, 111th Cong. § 122(a) (2009)(adding CAA § 813 (d)(1)).

(C) recommendations on how those programs and regulations should be improved or made more effective.[548]

Regulations are required to be promulgated within one year after the enactment of the act and require evidence financial responsibility, including responsibility for emergency and remedial response, well plugging, site closure, and post-injection site care.[549]

Section 123 of the Kerry-Boxer Bill mandates studies and reports regarding carbon capture.[550] The first required study is of the legal framework for geologic storage sites.[551] To produce this study the Administrator must establish, within 180 days of the enactment, a task force composed of: subject matter experts; nongovernmental organizations with expertise regarding environmental policy; academic experts with expertise in environmental law; state and tribal officials with environmental expertise; representatives of state and tribal attorneys general; representatives of EPA, the Department of the Interior, the Department of Energy, the Department of Transportation, and other relevant federal agencies; and members of the private sector.[552]

The Task Force is to study existing state, federal, and common laws that may serve as tools for risk management, health and environmental protection, financial security, and assumption of liability.[553] The Task Force also is to address private sector mechanisms like insurance and bonding, to manage environmental, health, and safety risks from closed geological storage sites.[554] Additionally, the Task Force shall study "the subsurface mineral rights, water rights, and property rights issues associated with geological storage of carbon dioxide, including issues specific to Federal land."[555] Eighteen months from the date of the enactment of S. 1733, the Task Force shall submit to Congress a report describing their findings and any recommendations.[556] In addition to the Task Force's report, the Administrator shall also conduct an independent study identifying under what circumstance EPA may apply the environmental statutes under its jurisdiction to $C0_2$ injection and storage.[557] The results of the study shall be submitted to Congress no longer than 18 months after the enactment of the Kerry-Boxer Bill.[558]

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[548] S. 1733, 111th Cong. § 122(a) (2009)(adding CAA § 813 (d)(2)(A)-(D)).
[549] S. 1733, 111th Cong. § 122(b) (2009)(adding 42 USC § 1421(e)(1)(2)). Evidence of financial responsibility can be demonstrated by: Insurance; Guarantee; Trust; Standby trust; Surety bond; Letter of credit; Qualification as a self-insurer; and any other method satisfactory to the Administrator. S. 1733, 111th Cong. § 122(b) (2009)(adding 42 USC § 1421(e)(2)(B)).
[550] *See generally* S. 1733, 111th Cong. § 123 (2009).
[551] S. 1733, 111th Cong. § 123(a) (2009).
[552] S. 1733, 111th Cong. § 123(a)(1)(A)(i)-(vii) (2009).
[553] S. 1733, 111th Cong. § 123(a)(1)(B)(i)-(iii) (2009).
[554] S. 1733, 111th Cong. § 123(a)(1)(B)(iv) (2009).
[555] S. 1733, 111th Cong. § 123(a)(1)(B)(v) (2009).
[556] S. 1733, 111th Cong. § 123(a)(2) (2009).
[557] S. 1733, 111th Cong. § 123(b)(1) (2009).
[558] *Id.*

The Kerry-Boxer Bill also adds a new CAA § 812, "Performance Standards for Coal-Fired Power Plants."[559] Not more than two years after enactment, the Administrator is to promulgate rules[560] for new standards that require covered electric generating units (EGUs)[561] initially permitted[562] after January 1, 2020, in order to achieve a sixty-five percent or more reduction in CO_2 emissions.[563] EGUs initially permitted between January 1, 2009 and January 1, 2020, are required to achieve a fifty percent reduction in CO_2 emissions.[564]

These standards are to be achieved by the earlier of January 1, 2025,[565] or four years after the Administrator releases her report on US commercial carbon capture facilities.[566] This report will be released when facilities using CSS technology meet, in the aggregate, several criteria. First, there must be facilities with least ten gigawatts (gW) of nameplate generating capacity and at least three gW must be EGUs and up to one gW may be from industrial applications "for which capture and sequestration of 3,000,000 tons of carbon dioxide per year on an aggregate annualized basis shall be considered equivalent to 1 gigawatt."[567] Second, there needs to be at "least 3 electric generating units, each with a nameplate generating capacity of 250 megawatts or greater, that capture, inject, and sequester

[559] S. 1733, 111th Cong. § 124 (2009)(adding CAA § 812).
[560] S. 1733, 111th Cong. § 124 (2009)(adding CAA § 812(e)).
[561] S. 1733, 111th Cong. § 124(a) (2009)(adding CAA § 812(a)(1)). A covered EGU is a utility unit that is required to have a permit under section 503(a) and is authorized under State or Federal law to derive at least 30 percent of its annual heat input from coal, petroleum coke, or any combination of these fuels. *Id.*
[562] S.1733, 111th Cong. § 124(a) (2009)(adding CAA § 812(a)(2)). Initially permitted is defined as: the owner or operator has received a preconstruction approval or permit under this Act, for the covered EGU as a new (not a modified) source, but administrative review or appeal of such approval or permit has not been exhausted. A subsequent modification of any such approval or permits, ongoing administrative or court review, appeals, or challenges, or the existence or tolling of any time to pursue further review, appeals, or challenges shall not affect the date on which a covered EGU is considered to be initially permitted under this paragraph. *Id.*
[563] S. 1733, 111th Cong. § 124(a) (2009)(adding CAA § 812(b)(1)). Emissions are measured annually.
[564] S. 1733, 111th Cong. § 124(a) (2009)(adding CAA § 812(b)(2)).Emissions are measured annually.
[565] S. 1733, 111th Cong. § 124(b)(1) (2009)(adding CAA § 812(b)(2)(B)). "If the deadline for compliance with paragraph (2) is January 1, 2025, the Administrator may extend the deadline for compliance by a covered EGU by up to 18 months if the Administrator makes a determination, based on a showing by the owner or operator of the unit, that it will be technically infeasible for the unit to meet the standard by the deadline. The owner or operator must submit a request for such an extension by no later than January 1, 2022, and the Administrator shall provide for public notice and comment on the extension request." S. 1733, 111th Cong. § 123(b)(1) (2009)(adding CAA § 812(b)(3)).
[566] "Not later than 18 months after the date of enactment of this title and semiannually thereafter, the Administrator shall publish a report on the nameplate capacity of units (determined pursuant to subsection (b)(2)(A)) in commercial operation in the United States equipped with carbon capture and sequestration technology, including the information described in subsection (b)(2)(A) (including the cumulative generating capacity to which carbon capture and sequestration retrofit projects meeting the criteria described in section 775(b)(1)(A)(ii) and (b)(1)(A)(iv)(II) has been applied and the quantities of carbon dioxide captured and sequestered by such projects)." S. 1733, 111th Cong. § 124(b)(1) (2009)(adding CAA § 812(d)).
[567] S. 1733, 111th Cong. § 124(a) (2009)(adding CAA § 812(b)(2)(A)(i))).

carbon dioxide into geologic formations other than oil and gas fields."[568] Third, there must be facilities capturing and sequestering in the aggregate at least 12 million tons of carbon dioxide per year, calculated on an aggregate annualized basis.[569]

No later than 2025 and at five-year intervals thereafter, the Administrator shall promulgate a rule reducing the maximum CO_2 emission rate "to a rate which reflects the degree of emission limitation achievable through the application of the best system of emission reduction, which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated."[570]

S. 1733 creates the Carbon Capture and Sequestration and Early Deployment Program[571] that encourages fossil fuel facilities to invest in CSS technology. Under this provision, in the absence of state regulatory objections,[572] private industry organizations may conduct a referendum to create a Carbon Storage Research Corporation[573] that shall operate as a division of the Electric Power Research Institute.[574]

The general purpose and mission of the Corporation is to administer a program to accelerate the commercial availability of carbon dioxide capture and storage technologies and methods, including technologies that capture and store, or capture and convert, carbon dioxide. Under such program competitively awarded grants, contracts, and financial assistance shall be provided and entered into with eligible entities. Except as provided in paragraph (8), the Corporation shall use all funds derived from assessments under subsection (d) to issue grants and contracts to eligible entities.

The grants, contracts, and assistance are to support commercial-scale demonstrations of carbon capture or storage technology projects capable of advancing the technologies to commercial readiness. Projects should encompass a range of different coal and other fossil fuel varieties, be geographically diverse, involve diverse storage media, and employ capture or storage, or capture and conversion, technologies potentially suitable either for new or for retrofit applications. To the extent feasible, the Corporation shall seek, to support at least five commercial-scale demonstration projects integrating carbon capture and sequestration or conversion technologies.[575]

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[568] S. 1733, 111th Cong. § 124(a) (2009)(adding CAA § 812(b)(2)(A)(ii))).
[569] S. 1733, 111th Cong. § 124(a) (2009)(adding CAA § 812(b)(2)(A)(iii))).
[570] S. 1733, 111th Cong. § 124(a) (2009)(adding CAA § 812(c)).
[571] *See generally,* S. 1733, 111th Cong. § 125 (2009).
[572] S. 1733, 111th Cong. § 125(b)(1)(B) (2009).
[573] S. 1733, 111th Cong. § 125(b)(1) (2009).
[574] S. 1733, 111th Cong. § 125(b)(3) (2009). *See also* S. 1733, 111th Cong. § 125(b),(c)(5) (2009) for the general composition, governance, status, and administration of the Corporation.
[575] S. 1733, 111th Cong. § 125(c)(1) & (2) (2009).

Entities eligible for Corporation assistance may include distribution utilities, electric utilities and other private entities, academic institutions, national laboratories, federal research agencies, state and tribal research agencies, nonprofit organizations, or consortiums of two or more entities but not pilot or small-scale projects.[576] All projects must also meet eligibility criteria of CAA § 780(b).[577] To reward early action, at least fifty percent of funds are to be used to defray costs for a least five generating units where utilities have already committed resource to a large scale generation unit with integrated carbon capture and sequestration or conversion applied to a substantial portion of the unit's carbon dioxide emissions.[578] Grants maybe used for test projects consistent with purposes of the Corporation, which shall publish the results of these tests.[579]

S. 1733 includes provisions concerning administrative expenses,[580] programs and budgets,[581] records and audits,[582] public access,[583] and annual reports.[584] Funds for the Corporation are to come from an assessment on distribution utilities based on relative carbon dioxide emission rates of different fossil fuel-based electricity.[585] Assessments per KWh shall not be less than, $0.00043 for coal, $0.00022 for natural gas, and $0.00032 for oil.[586] The Corporation may adjust assessments if needed to reflect fuel changes and to generate between $1 and 1.1 billion dollars annually.[587] No Corporation assessment funds my used for lobbying.[588] The Corporation may bring an action to compel payment of assessments and if successful may require costs for bringing such action.[589] The costs to utilities shall be recoverable costs.[590]

To maintain the legitimacy of the Corporation, no later than five years after the establishment of the Corporation the Comptroller General of the United States is required to analyze and report to Congress, assessing the Corporation's activities, including project selection and methods of disbursement of assessed fees, the prospects for commercialization of carbon capture and storage technologies, and

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[576] S. 1733, 111th Cong. § 125(c)(3) (2009).
[577] S. 1733, 111th Cong. § 125(c)(3) (2009).
[578] S. 1733, 111th Cong. § 125(c)(4) (2009).
[579] S. 1733, 111th Cong. § 125(c)(6) (2009).
[580] S. 1733, 111th Cong. § 125(c)(7) (2009).
[581] S. 1733, 111th Cong. § 125(c)(8) (2009).
[582] S. 1733, 111th Cong. § 125(c)(9) (2009).
[583] S. 1733, 111th Cong. § 125(c)(10) (2009).
[584] S. 1733, 111th Cong. § 125(c)(11) (2009).
[585] S. 1733, 111th Cong. § 125(d)(1) (2009).
[586] S. 1733, 111th Cong. § 125(d)(1)(A) (2009).
[587] S. 1733, 111th Cong. § 125(d)(1)(B) (2009).
[588] S. 1733, 111th Cong. § 125(k) (2009
[589] S. 1733, 111th Cong. § 125(g) (2009). *See also* S. 1733, 111th Cong. § 125(d)(2,(3)) (2009) (for investment and reversion of unused funds); S. 1733, 111th Cong. § 125(e) (2009)(for assessment, collection, and remittance provisions); S. 1733, 111th Cong. § 125(f)(for determined what qualifies as a fossil fuel based electricity deliveries from which the value of assessments are determined, this includes DOE rulemaking on the subject).
[590] S. 1733. 11th Cong. § 125(i).

the adequacy of funding, and administration of funds. The report shall also make such recommendations as may be appropriate in each of these areas. The Corporation shall reimburse the Government Accountability Office for the costs associated with performing this midcourse review.[591]

§ 4(d) American Power Act

Because S. 1733 was expected to have great difficulty in obtaining the sixty votes needed to prevent a filibuster,[592] on May 12, 2010 a compromise senate bill was released that is known as the American Power Act (AmPA).[593] The bill is primarily the work of John Kerry (D-Mass), Chairman of the Foreign Relations Committee, and Joe Lieberman (I-Conn), Chairman of the Homeland Security and Governmental Affairs Committee. Senator Lindsey Graham (R-S.C.) played a major role until he ended his participation when it appeared Senator Reid was going to give priority to immigration legislation.[594] The AmPA deals with energy policy and climate change through a comprehensive program that involves the federal government playing a more important role in nearly ever aspect of the nation's economy. The bill aims to reduce CO_2 equivalent emissions by 17% in 2020 and by over 80% by 2050.[595] The nearly one thousand pages of the bill are divided into five titles.

Title I subsidizes nuclear power, encourages domestic oil and gas production (including offshore production), subsidizes carbon capture and sequestration deployment, and supports energy efficiency improvement programs. Title II mandates GHG reduction through a cap-and-trade program, with both floor and ceiling prices, which adds a new Title VII to the CAA. This title also adds new requirements for hydrofluorocarbons and black carbon. Title III is titled "Consumer Protection." It specifies how the allowances that are distributed will be used to benefit energy consumers including relief for households with incomes of up to 250 percent of the poverty line. Title IV is titled "Job Protection and Growth." It is primarily a subsidy program for industry that will offset the costs of compliance with the bill's GHG emissions reduction requirements, and it provides for charges to be imposed on imports from countries that have not taken action to limit GHG emissions. Title IV also has a program to subsidize natural gas-powered vehicle production and use, and it contains a carbon biological sequestration program that is essentially a subsidy for the agriculture industry. Title V is a program to fund international efforts to reduce GHG emissions and to fund mitigation and adaptation

[591] S. 1733, 111th Cong. § 125(h) (2009).

[592] Leora Falk, *Senators Seek 17 Percent Emissions Cut, Support for Nuclear Power in Compromise,* 40 Env't Rep. (BNA) 2814 (Dec. 11, 2009).

[593] American Power Act, Discussion Draft, 11th Congress, *available at* http://kerry.senate.gov/imo/media/doc/APBill3.pdf (last visited Dec. 4, 2010).

[594] Dean Scott, *Bill Release Now Set for Week of May 10; Offshore Drilling Provisions Being Rewritten,* 41 Env't Rep. (BNA) 984 (May 7, 2010).

[595] American Power Act, *supra* note 598, at § 702(2) & (4).

efforts. Title VI has various provisions aimed at protecting communities from climate change impacts through adaptation strategies.

Title I, Subtitle C provides for a program to encourage the commercialization of carbon capture and sequestration technology to enable coal to be used with reduced adverse environmental impact.[596] One year after the enactment of this Act, the Administrator of EPA, working with the Secretary of Energy and the Secretary of Energy is to submit to Congress a report that addresses the key legal, regulatory, and other barriers to carbon capture and storage.[597] Section 1402 calls for a study of the legal framework for geological storage sites that is due eighteen months after enactment and a study of how environmental laws would apply to CO_2 sequestration that is to be submitted not later than one year after enactment. If thirty or more states (including the District of Columbia) seek federal assistance, the Secretary of Energy shall establish a special funding program.[598] The Secretary is to establish a Carbon Capture and Sequestration Program Partnership, with a majority of the voting members from the fossil-fueled electric power industry, to make recommendations to the Secretary concerning activities carried out using the special funding programs.[599] The special funding programs are to support projects that accelerate the commercial availability CCS.[600] Funding will be derived from an assessment on electricity for all fossil fuel-based electricity sold to electric consumers to generate about $2 billion a year.[601] The assessments are to be collected as specified in §1417 and as specified in regulations to be promulgated within 180 days of enactment of the AmPA.[602] Costs are to be recovered from consumers of electricity, and recovery may not be denied by rate-making authorities.[603]

Commercial deployment of CCS technology is regulated pursuant to section 1431, which amends a newly created CAA §794 to require the Administrator to promulgate regulations providing for the distribution of emission allowances, consistent with the statute, "to support the commercial deployment of carbon capture and permanent sequestration technologies in electric power generation and industrial operations".[604] At least a 50 percent reduction in CO_2 is required from the electric power industry, and the gas must safely and permanently be sequestered in a geologic formation in the United States.[605] Bonus allowances are available for CCS at levels of CCS efficiency above 50 percent.[606] CAA §794 is structured to provide incentives for facilities to embrace CCS early and capture as much CO_2 as possible.

[596] *Id*. at §§ 1401-1432.
[597] *Id*. at § 1401.
[598] *Id* . at § 1412.
[599] *Id*. at § 1413.
[600] *Id*. at § 1414.
[601] *Id*. at § 1415.
[602] *Id*. at § 1417(c).
[603] *Id.* at § 1420.
[604] *Id*. at § 1431 (adding CAA § 794(b)).
[605] *Id*. at § 1431 (adding CAA §794(c)).
[606] *Id*. at § 1431 (adding CAA §794(d)).

This is to be accomplished by the Administrator allocating the allowances provided in CAA §781(c)(1), which begin in 2017 with 0.8% of the total allowances and climb to 10.0% in 2030 through 2034 to deploy commercial scale CCS. Up to 15% of these allowances may be used by industrial sources to utilize CCS.[607]

Within two years after enactment of the AmPA the Administrator is to promulgate regulations concerning the distribution of allowances.[608] The Administrator may use reverse auctions in which qualifying electric generating units and industrial sources bid on how many allowances they require per ton of CO_2 they plan to sequester and the estimated quantity they will permanently sequester in a ten-year period. The Administrator will select the projects that have the lowest cost and that meet the EPA specifications.[609]

Section 1432 amends the CAA to create a section 789. It directs the Comptroller General, when directed by the Administrator, to study CCS technology and the barriers to deployment and recommend how to address these barriers. The study can be used as a basis for adjusting the quantity of allowances used for CCS incentives if directed to do so by the Secretary of Energy.[610]

Subtitle C, Part IV, § 1441, would impose new performance standards on coal-fired power plants through a new CAA "Title VIII—Greenhouse Gas Standards." EGUs permitted in 2009 or thereafter must reduce CO_2 emissions by 50% four years after the Administrator publishes a finding that CCS is commercially viable based on operating facilities actually capturing and sequestering at least 12 million tons per year.[611] Plants permitted in 2020 and thereafter are to meet emission limitations that represent at least a 65% reduction in CO_2 releases.[612] The CAA amendments aim to promote the acceleration of a transition of coal-fueled power plants to lower GHG emissions by using more efficient technologies.[613]

Title II, Subtitle B, § 2101, deals with the disposition of allowances by creating a Part G in the new CAA Title VII. CAA §721 lists the number of allowances from 2013 to 2050 and thereafter; the declining number of allowances creates a steady reduction of the allowable emissions called the cap. Entities subject to the allowance program include `geological sequestration sites as defined at CAA §700(26) & (27), but GHGs captured and sequestered are not considered to be GHG emissions, except to the extent they are later released into the atmosphere.[614]

[607] *Id*. at § 1431 (adding CAA §794(g)(1)).
[608] *Id*. at § 1431 (adding CAA §794(b) & (e)).
[609] *Id*. at § 1431 (adding CAA §794(e)).
[610] *Id*. at § 1432 (adding CAA § 789).
[611] *Id*. at § 1441 (adding CAA § 801(b)(2)(B))
[612] *Id*. at § 1441 (adding CAA § 801(b)(1)).
[613] *Id*. at § 1441 (adding CAA § 802).
[614] *Id*. at § 2101 (adding CAA §§ 700(12)(E) & 700(19)(B)).

Sequestration is defined at CAA §700(48)(B)(ii) to include geological sequestration.[615]

CAA §781 allocates allowances for: consumer protection; job protection; clean energy development and deployment (including commercial deployment of carbon capture and sequestration). CAA §781(e)(1)(A) provides allowances for the deployment of CCS technology that are a percentage of all allowances. In 2017 and 2018 the percentage is 0.8. In 2020 it increases to 4.5 and from 2021 to 2030 it increases from 5.0 to 10.0 where it remains through 2034. The requirements for reporting GHG emissions are modified to include mandating regulations to be promulgated to require reporting of data concerning the capture and sequestration of GHGs.[616]

§ 4(e). S. 3590 & S. 3591

On July 14, 2010, Senators Jay Rockerfeller (D-W.Va.) and George Voinovich (R-Ohio), introduced legislation that would provide $2 billion a year for ten years to fund CCS demonstrations at large fossil-fuel electric power plants. It would be funded by a charge on electricity. The proposed legislation also would authorize $20 billion in loan guarantees for CCS projects. The bills would require at least 50 percent of the CO_2 at new plants to be sequestered. It would establish a fund to cover the cost of accidents and long-term storage at CCS sites to be paid by the utilities. The CAA would no longer be applicable to CCS facilities.[617]

The November 2010 national elections will have a major effect on climate change legislation. In the House the Republican Party will assume the leadership role. In the Senate, committees will operate with fewer Democrats. Republicans have elected not to continue the House Select Committee on Energy Independence and Global Warming.[618] Legislative proposals will become more narrowly focused on issues that can obtain Republican support.[619] How this change in the composition of the Congress will effect the development of CCS is unknown at this time.

[615] *Id*. at § 2101 (adding CAA §700(48)(B)(ii)).
[616] *Id*. at § 2101 (adding CAA §713(b)(1)(A)(iv)).
[617] Steven D. Cook, *Rockefeller, Voinovich Bill Would Provide $2 Billion a Year for Carbon Sequestration,* 41 Env't Rep. (BNA) 1570 (July 16, 2010).
[618] *House GOP Kills Global Warming Committee,* NEW HAVEN REGISTER, Dec. 2, 2010, *available at* http://www.nhregister.com/articles/2010/12/02/news/aa9globalwarmingcomm120210.txt (last visited Jan. 3, 2011).
[619] Dean Scott, *Democrats See Hope in Piecemeal Approach To Advancing Climate Change, Energy Bills,* 41 Env't Rep. (BNA) 2178 (Oct. 1, 2010).

§ 5. Conclusion

For the foreseeable future costs will be the primary barriers to the implementation of CCS. This includes the high retrofit costs for existing pulverized coal-fired plants, the high costs of separating carbon dioxide from the other gases and liquefying it, the costs of the needed transportation infrastructure, the costs of creating a storage facility and monitoring long-term storage, and the costs of alternative generating technologies such as IGCC. The absence of any commercial-scale use of CCS at a large power plant is an important constraint on program development because meaningful cost data is difficult to obtain. DOE has focused on IGCC as a promising technology for use with CCS, but it is more costly than conventional technology, it does not result in significant further reductions of conventional emissions, and it is not an effective solution to emissions from existing facilities.

The projected high cost of CCS will also be affected by whatever develops concerning a CO_2 emissions trading program. If cap-and-trade legislation is enacted and it significantly raises the costs of using fossil-fuel energy in the United States, CCS could be an attractive option to potentially avoid both the cap on emissions and the cost of allowances. Sequestration may also become more attractive after EPA develops and implements a regulatory regimen to control CO_2 based on the CAA. However, EPA's endangerment finding for CO_2 may also create additional regulatory hurdles on the CCS development path.

At this time carbon sequestration has not been demonstrated to be a commercially viable technology. No sequestration application has been successfully deployed at the scale necessary for demonstrating it is a practical and reasonable way to deal with releases of carbon to the atmosphere. The fact that sequestration has been used for enhanced oil and gas production does not demonstrate that long-term sequestration of commercial quantities of CO_2 will be a viable option. The experience of Yucca Mountain regarding disposal of nuclear waste demonstrates the difficulty of making a prospective case that a hypothetical hazard or occurrence will not occur. For this reason, if sequestration on a commercial scale is to occur the Department of Energy will need to play a major role in funding and evaluating this technology at a commercial scale and the federal government will need to provide a legal environment that nurtures a new industry.

CO_2 capture and storage could become a necessity if coal is to be used for electric power generation in a carbon constrained economy, but the high costs of CCS could make natural gas fired plants as well as nuclear power and renewable power more attractive to utilities than trying to deal with sequestration. Coal accounted for 48% of the U.S. electric power generated in 2008, but the majority of the coal-fired plants are more than thirty years old.[620] Natural gas-fired power plants generated 21% of the electricity, but most plants were built in the past ten years, and it is the technology favored by the electric power sector.[621] Natural gas has lower carbon and conventional emissions than coal, but it has enhanced attractiveness because prices dropped from a high of $10.82 per thousand cubic feet (mcf) in mid-2008[622] to $4.21 per mcf on December 1, 2010, as domestic production increased.[623] Many coal-burning power plants are being retired or repowered to use natural gas.[624] Renewable portfolio requirements are helping to spur wind and solar generation.[625] Energy efficiency improvements can reduce demand at less than half the cost of constructing new generating facilities.[626] While regulatory demands to reduce carbon emissions could make CCS more attractive, the continuously more stringent pollution control requirements and the associated costs make coal-fired power plants a questionable investment. Sequestration is a way of dealing with emissions from an electric generation technology that needs to be improved if it is to avoid being phased out. This creates ongoing pressure on sequestration supporters to lower costs and demonstrate the commercial viability of geological carbon sequestration in order to use the nation's lowest cost and most plentiful source of energy—coal.

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620 Christopher Van Atten, *et al.,Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the United States* 9 (June 2010), available at http://www.nrdc.org (last visited Dec. 4, 2010).
621 *Id.* at 9, 12.
622 *Id.* at 12.
623 U.S. Energy Information Administration, available at http://tonto.eia.doe.gov/oog/info/ngw/ngupdate.asp (last visited Dec. 4, 2010).
624 Van Atten, *supra* note 623, at 13.
625 *See generally,* Lincoln L. Davies*, Power Forward: The Argument For A National RPS*, 42 CONN. L. REV. 1339 (2010).
626 Van Atten, *supra* note 623, at 15.