State and Regional Control of Geological Carbon Sequestration (Part I)

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Editors' Summary

In the near future the use of coal may be legally restricted due to concerns over the effects of its combustion on atmospheric carbon dioxide concentrations. Carbon capture and geologic sequestration offer one method to reduce carbon emissions from coal and other hydrocarbon fuel. While the federal government is providing increased funding for carbon capture and storage, congressional legislative efforts to limit carbon emissions have failed. However, regional and state bodies have taken significant actions both to regulate carbon and to facilitate its capture and storage, addressing the technical and legal problems that must be resolved in order to have a viable carbon storage program. Several regional bodies have formed regulations and model laws that affect carbon capture and storage, and three bodies comprising 23 states have cap-and-trade programs in various stages of development. New state laws are being enacted that encourage carbon storage, and existing state laws affect the liability and viability of carbon storage projects. A subsequent Article will examine specific legislation concerning carbon capture and storage, or the lack of it, in 18 western states.

I. Carbon Storage

Carbon sequestration may be accomplished through either storage in a geologic depository or by using a biologic process in which carbon dioxide (CO_2) is removed from the atmosphere by plants that store carbon.[1] Biological sequestration is a well-established and cost-effective way to sequester carbon, but it is difficult to quantify the benefits. Geologic sequestration involves the separation of CO_2 from an exhaust gas stream and compressing it, transporting it to a suitable site, and injecting it into a deep underground formation. It will be some time in the future before sequestration in geologic formations is proven to be an effective and economical way to reduce CO_2 emissions to the atmosphere, but a major benefit from developing effective geologic sequestration is that America's abundant supply of coal could be utilized without the adverse environmental impacts associated with CO_2 emissions. However, there are risks from geologic sequestration that have been identified, including changes in soil chemistry that could harm the ecosystem, effects on water quality due to acidification, effects of geologic stability, and the

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1. 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).

potential for large releases that could harm or suffocate people and animals.[2]

After a brief discussion of the main components of CO_2 storage (CO_2 capture, transportation, storage, and long-term liability), this Article explores major legal and policy actions taken by regional and state bodies that will impact CO_2 storage. Federal control of geologic storage has been covered in another publication.[3]

A. Carbon Capture

Carbon capture and storage (CCS) begins by separating CO_2 from other gases, which may be done before or after fuel is combusted.[4] Post-combustion capture involves concentrating the exhaust gases into a stream of nearly pure CO_2, and then compressing it to convert it from gas to a supercritical fluid before it is transported to the injection site by pipeline. 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.

The majority of the costs of storage result from separating and capturing CO_2 from flue gas.[5] 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 low 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 certain carbon capture processes. Conventional power plant CO_2 emissions are about 13% to 15% by volume, which increases 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.[6] If the nitrogen in air is removed prior to combustion, such as occurs in the oxyfuel process, the CO_2 in the exhaust stream is concentrated, and it is less costly to separate a given amount of the gas.[7] Integrated Gasification Combined Cycle (IGCC) plants also have lower CO_2 separation costs than conventional power plants because the CO_2 concentration is higher, therefore less energy is required to remove a ton of CO_2.[8] An Intergovernmental Panel on Climate Change (IPCC) report estimates the cost of carbon capture at 1.8 to 3.4 cents/kilowatt hour (kWh) for a pulverized coal plant; 0.9 to 2.2 cents/kWh for a coal-burning IGCC plant; and 1.2 to 2.4 cents/kWh for a natural gas combined-cycle power plant.[9]

After the CO_2 is removed from the exhaust gas stream at either a conventional or an IGCC facility, it must be compressed to liquefy it for transport.[10] This reduces the efficiency of the electric generation process because of the energy required to liquefy CO_2. It is estimated that carbon capture from a new IGCC plant would increase the cost of electricity production by less than one-half the cost of carbon capture from a new pulverized coal plant, in part because it produces a higher concentration CO_2 stream, which lowers energy requirements for liquefying the CO_2.[11] But it is pulverized coal plants that generate 99% of the electricity produced from burning coal.[12] Carbon capture from most conventional power plants that use pulverized coal would require post-combustion capture using technologies such as chilled ammonia, which could increase the cost of electricity by 59% according to a 2007 U.S. Department of Energy (DOE) report.[13]

CCS will dramatically increase the cost of energy. In 2009, DOE stated that 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%.[14] Overall CO_2 storage costs are estimated at $25 to $90 per metric ton, depending on the source.[15] DOE estimates that storage from an IGCC facility will increase the average cost of electricity from 7.8 cents per kWh to 10.2 cents per kWh.[16] A report prepared at the University of Utah found the cost of carbon capture to be about $40 per ton and underground storage costs about $10 per ton, which would add 7.5 cents to the cost of a kWh.[17] This cost would be added to the average delivered

2. *International Climate Study Examines Feasibility of CO_2 Storage,* XVI Clean Air Report (Inside EPA) 4:4 (Feb. 24, 2005). *See also* IPCC Special Report: Carbon Dioxide Capture and Storage (Bert Metz et al. eds., 2005), *available at* http://www.ipcc.ch/pdf/special-reports/srccs/srccs_summaryforpolicymakers.pdf [hereinafter IPCC Special Rep.].
3. Arnold W. Reitze Jr., *Federal Control of Geological Carbon Sequestration,* Pace Envtl. L. Rev. (forthcoming 2011).
4. U.S. Government Accountability Office (GAO), 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].
5. *See* National Energy Technology Laboratory (NETL), Technologies: Carbon Sequestration, http://www.netl.doe.gov/technologies/carbon_seq/ (last visited Dec. 30, 2010).
6. GAO, *supra* note 4, at 18.
7. Oxyfuel, Institue for Clean and Secure Energy, Univ. of Utah (2009).
8. *Id.*
9. IPCC Special Rep., *supra* note 2, at 341.
10. *Id.* at 22.
11. *Id.* at 18.
12. NETL, Carbon Sequestration: CO_2 Capture, http://www.netl.doe.gov/technologies/carbon_seq/core_rd/co2capture.html (last visited Dec. 30, 2010).
13. *Industry Downplays DOE Report Doubting CO_2 Capture Process,* XVIII Clean Air Rep. (Inside EPA) 15:4 (July 26, 2007).
14. U.S. DOE, Carbon Capture and Storage R&D Overview, http://www.fossil.energy.gov/programs/sequestration/overview.html (last visited Dec. 30, 2010).
15. IPCC Special Rep., *supra* note 2.
16. NETL, *supra* note 12.
17. Stephen Sicilliano, *Sequestration Called Best Way to Achieve Short-Term Reductions of Carbon Emissions*, 38 Env't Rep. (BNA) 2286 (Oct. 26, 2007).

cost of 8.9 cents per kWh.[18] The American Coalition for Clean Coal Electricity, a coal-fired electric industry group, estimates the cost of having carbon storage available by 2025 at $17 billion.[19] The added cost is projected by a Massachusetts Institute of Technology (MIT) study to nearly double the cost of a kWh of electricity.[20] These increases to the cost of electricity may encourage the use of various funding mechanisms that hide the costs. These could include investment tax credits, carbon storage credits, subsidies based on a cap-and-trade program, federal loan guarantees, and federal financing.[21]

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 per kWh. Thus, CCS, according to the IPCC, would increase the cost of producing electricity by about 30% to 60%. These estimates are considerably lower than the DOE estimates. 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.[22] The cost of storage 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. A California Public Utilities Commission report of June 12, 2009, estimates electric power will cost 16.7% more in 2020, even without a storage requirement.[23]

B. CO_2 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, transportation will be costly, because a 1,000-megawatt (MW) plant will consume about 13,000 tons of coal each day.[24] 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.[25] Thus, a 1,000-MW power plant using 13,000 tons per day of Powder River Basin coal would produce about 26,824 tons of CO_2 per day.[26] 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.[27] 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.[28] Electrical generation in 2008 in the United States produced 2,363.5 million metric tons of CO_2.[29] This would result in the generation of 163,081 million cubic feet of super critical CO_2 per year, which is a column one square mile at its base and over 1.11 miles high.[30]

In addition to the significant engineering and economic issues concerning transporting CO_2, carbon storage raises legal issues concerning CO_2 transport and the potential liability for transportation mishaps. CO_2 is compressed into a supercritical fluid for transport, usually via a pipeline, to a site where it can be injected far below the ground. Safety regulations for these pipelines will be within the jurisdiction of the U.S. Department of Transportation's (DOT's) Pipeline and Hazardous Materials Safety Administration (PHMSA) for pipelines that affect interstate commerce. The PHMSA also provides minimum standards for states that regulate intrastate pipelines.

Before large-scale CO_2 transport occurs, the agency with responsibility for rates and terms of service for interstate CO_2 pipelines must develop regulations. The Federal Energy Regulatory Commission (FERC) has the statutory responsibility to regulate sites, rates, and terms for interstate natural gas pipelines. However, FERC does not appear to have legal authority over CO_2 pipelines. The Surface Transportation Board (STB) has jurisdiction over pipelines that transport any commodity other than water, gas, or oil.[31] But the STB's predecessor interpreted its statutory authority to exclude all gas types, including CO_2. Thus, it would

18. GAO, *supra* note 4, at 23.
19. Michael Kinsley, *U.S. Shouldn't Give Up on Clean Coal,* Salt Lake Trib., Mar. 21, 2009, at A13.
20. MIT, The Future of Coal, Summary Report 19 (2007), *available at* http://web.mit.edu/coal/The_Future_of_Coal.pdf (MIT 2007) (last visited Dec. 30, 2010).
21. Steven D. Cook, *Dorgan Report Sees Minimum of $110 Billion Needed to Deploy Carbon Capture, Storage,* 40 Env't Rep. (BNA) 2762 (Dec. 4, 2009).
22. IPCC Special Rep., *supra* note 2, at 10.
23. Carolyn Whetzel, *Report Says State's Plan to Boost Renewable Portfolio Ambitious, Costly,* 40 Env't Rep. (BNA) 1463 (June 19, 2009).
24. *See* Power 4 Georgians, http://power4georgians.com/wcpp.aspx (last visited Dec. 30, 2010).
25. 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 CO_2 that weighs 3.664 times the weight of the carbon, based on the atomic weights of oxygen and carbon. Babcock & Wilcox, Steam, Its Generation and Use 2-4, 2-8, tbl. 10 (37th ed. 1960); B.D. Hong & E.R. Slatick, *Carbon Dioxide Emission Factors for Coal*, U.S. DOE, Energy Information Administration (EIA), http://www.eia.doe.gov/cneaf/coal/quarterly/co2_article/co2.html (last visited Dec. 30, 2010).
26. For Powder River Basin coal, 13,000 tons of coal per day, minus its moisture content, multiplied by its carbon content is the weight of the carbon, and multiplied by the relative weight of CO_2 will produce 26,824 tons per day of CO_2 (13,000 x .76 x .741 x 3.664). Calculated from data found in Babcock & Wilcox, *supra* note 25, at 2-8, 2-9.
27. Chemical Engineer Handbook, 5th ed. 3-162 (Robert H. Perry ed. 1953). The *IPCC Special Report*, *supra* note 2, provides a range of numbers, but says the density is 1,032 kilograms per cubic meter at 20 degrees C and 19.7 bar pressure, which converts to 64.4 pounds per cubic foot.
28. An NFL football field is 360 by 160 feet, which is 57,600 square feet. *See* http://www.sportsknowhow.com (last visited Dec. 30, 2010). A power plant's production of 26,824 tons per day of CO_2 at 69 cubic feet per ton results in 1.85 million cubic feet of super critical CO_2. Divided by 57,600, this gives a depth of 32.13 feet.
29. U.S, Envtl. Protection Agency (EPA), *2010 Inventory of Greenhouse Gas Emissions and Sinks,* at 3-1, *available at* http://www.epa.gov/climatechange/emissions/downloads10/US-GHG-Inventory-2010_Chapter3-Energy.pdf.
30. 5,280 x 5,280 = 27.88 million sq. ft. 163,081 million/ 27.88 million = 5,849.4 ft or 1.11 miles.
31. 49 U.S.C. §15301.

appear that legislation is needed to establish which agency will regulate pipelines used for CO_2 transport.[32]

If pipelines are to be constructed, "not in my backyard" (NIMBY) opposition should be expected. In Montana, H.B. 338 became law on April 16, 2009, which grants owners of pipelines transporting CO_2 common carrier status. This allows them to use eminent domain over private property owners.[33]

C. CO_2 Storage

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.[34] 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 storage in the United States and to then assess the capacity.[35] On June 3, 2009, the U.S. Department of the Interior (DOI), in consultation with DOE, the U.S. Environmental Protection Agency (EPA), and the USGS, issued their report recommending a framework for identifying suitable CO_2 storage sites.[36] The report is more conservative than DOE estimates, because it does not include coal deposits as potential storage sites[37]; it only evaluates available sites that are 3,000 to 13,000 feet deep; and it limits evaluation to sites that can store 2 million cubic meters of CO_2 or more. This amount could be emitted in a short time by a single coal-burning power plant. The report 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 and topped with an impervious cap that prevents the loss of the sequestered CO_2 because of physical and geochemical trapping.[38] Issues of concern in the report include the effect of storage on mineral extraction and surface activities, such as grazing, recreation, and community development. Sites also need to be evaluated for their potential to induce earthquakes.[39]

CO_2 storage can be based on physical trapping or geochemical trapping. With physical trapping, the buoyant CO_2 is trapped by rock, 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 usually contain other gases and liquids, primarily brine, that will be displaced or have their pressure increased by the injection.[40] Geothermal trapping occurs when CO_2 reacts chemically with minerals in the geological formation and forms solid minerals.[41] It is expected that the CO_2 will be injected at depths of over 800 meters (2,600 feet) into geological formations that will sequester it for hundreds to thousands of years.[42]

While CO_2 injection has been widely used to enhance oil recovery and to force methane out of coal beds for recovery and use,[43] we do not yet 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. The supercritical liquid will be injected, using proven technology, at a depth of about 800 meters (2,625 feet) in order to keep the CO_2 in a supercritical state where it cannot be distinguished whether it is in a liquid or a gas phase.[44]

It is estimated by the International Energy Agency (IEA) that about 10,000 large-scale CCS projects will be needed by 2050 to hold global warming to three degrees Celsius by the end of this century. There are now four: Sleipner in the North Sea and Snohvit in the Barents Sea, Norway, both operated by StatoilHydro; the Salah project in Algeria, operated by British Petroleum, Somatrach, and StatoilHydro; and the North Dakota facility discussed below.[45] Since 1996, the 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.[46]

Some CO_2 is captured at natural gas plants, but it is not sequestered.[47] 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 in this process, CO_2, sulfur dioxide, and mercury are removed from the gas stream. The gas stream, which is 96% CO_2, is pressurized until it

32. GAO, *supra* note 4, at 45.
33. Perri Knize, *Montana Governor Signs Measures Easing Path to Carbon Sequestration, Transport,* 40 Env't Rep. (BNA) 1202 (May 22, 2009).
34. The Future of Coal, Summary Report 44, *supra* note 20.
35. Pub. L. No. 110-140 (2007).
36. U.S. DOI, Framework for Geological Carbon Sequestration on Public Land (2009).
37. *See* NETL. Carbon Sequestration: Storage, http://www.netl.doe.gov/technologies/carbon_seq/core_rd/storage.html (last visited Dec. 30, 2010) (citing coal seams as one viable storage option for CO_2).
38. Leora Falk, *U.S. Geological Survey Develops Methodology to Assess Carbon Dioxide Storage Potential,* 40 Env't Rep. (BNA) 618 (Mar. 20, 2009).
39. Steven D. Cook, *Site Selection Criteria Recommended for Geologic Storage of Carbon Dioxide,* 40 Env't Rep. (BNA) 1292 (June 5, 2009).
40. Alexandra B. Klass & Sara E. Bergan, *Carbon Sequestration and Sustainability,* 44 Tulane L. Rev. 237, 248 (2008).
41. GAO, *supra* note 4, at 10.
42. *Id.*
43. Cook, *Site Selection Criteria*, *supra* note 39.
44. U.S. EPA, 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 CO_2 is 88 degrees F.
45. 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 4, 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, n.7 [hereinafter Klass & Wilson, *Liability*].
46. GAO, *supra* note 4, at 28. A list of the sequestration projects throughout the world is maintained by the IEA, *available at* http://co2captureandstorage.info/co2db.php.
47. GAO, *supra* note 4, at 17.

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 transported 205 miles by pipeline to an oil field near Weyburn, Saskatchewan, Canada, where it is injected into one of 37 injection wells used to enhance oil recovery. The facility began sequestering CO_2 in 2000. It handles 8,000 metric tons of CO_2 each day.[48] None of the four existing storage projects was designed for long-term storage. They all are used to enhance hydrocarbon recovery. However, it appears that some of the injected CO_2 may remain in the depleted oil reservoirs permanently.[49]

DOE, on December 4, 2009, announced three new projects that will receive up to $979 million in federal funds, to be leveraged with $2.2 billion in private funds to help demonstrate commercial-size CCS deployment. American Electric Power, Inc. will design, construct, and operate a chilled ammonia capture process projected to capture 90% of the CO_2 from a 235-MW flue gas stream at the 1,300-MW Mountaineer Power Plant near New Haven, West Virginia. The CO_2 will be injected into two saline formations approximately 1.5 miles below the surface.[50] The Southern Company Services will retrofit a 160-MW flue gas stream at Alabama Power's Barry facility near Mobile, Alabama, to capture CO_2 and sequester up to one million metric tons per year in deep saline formations.[51] Summit Texas Clean Energy, LLC, will capture 90% of the CO_2 at a 400-MW plant to be built near Midland-Odessa, Texas. The CO_2 will be compressed and transported to oilfields in the Permian Basin of west Texas to be used for enhanced oil recovery.[52] President Barack 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 storage projects operational by 2016.[53]

Many technical problems need to be overcome in order to have a viable carbon storage program, but cost-effective environmental protection requirements, settlement of the ownership issues concerning carbon storage, and resolution of long-term liability are also issues that need to be resolved. Perhaps the first step will be to define CO_2 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."[54] While large-scale CCS has not yet occurred, a body of law has developed concerning enhanced oil recovery (EOR) and the use of geologic reservoirs for the storage of natural gas 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 coming from EOR. This reduces the potential conflicts, since all property owners are participants. If operations have not been unitized, the operator would have significant exposure to tort or property-based litigation.[55] Natural gas storage requires compliance with the state law on ownership of the depleted oil and gas reservoir pore space. Under the Natural Gas Act of 1938, interstate pipelines have eminent domain powers that apply to subsurface storage facilities.[56] Storage of natural gas requires payment to the subsurface owner of the fair market value of the right to store natural gas, "but the law of valuation remains unclear in most states and is largely undecided."[57]

II. Regional Storage Efforts

In an effort to control and influence greenhouse gas (GHG) regulation, some states work with the IOGCC, which represents the oil and gas interests of its 38 member states and nine international affiliates and has been an advocate of states' rights to govern petroleum resources within their borders.[58] Because the IOGCC views CCS as one of the best available methods to deal with the CO_2 released from current methods of fossil-fueled electric power generation, it formed a Geological Sequestration Task Force in 2002. In 2007, the task force, now the Carbon Capture and Storage Task Force, produced a comprehensive model legal and regulatory framework for geologic storage of CO_2 that advocates state- and provincial-level regulation of stored CO_2.[59]

Other efforts to control GHG regulation and influence federal policy led 23 eastern, midwestern, and western states to participate in three different regional approaches to GHG control.[60] Although each group emphasizes different goals and uses different paths to regulate and enforce its policies, these regional bodies provide varying levels of cooperation, investment, and direction for addressing climate change issues. Since 2005, cap-and-trade programs have been the main approach favored by regional programs attempting to reduce emissions of GHGs, with some programs specifically incorporating CCS as one type of reduction method. The oldest and most developed group, the

48. CO_2 Sequestration, http://www.basinelectric.com:80/Gasification/CO2/index.html (last visited Mar. 3, 2010).
49. *See* Dakota Gasification Company, *Carbon Capture and Sequestration: The Greatest CO_2 Story Ever Told*, http://www.dakotagas.com/CO2_Capture_and_Storage/index.html (last visited Dec. 7, 2010).
50. U.S. DOE, *Secretary Chu Announces $3 Billion Investment for Carbon Capture and Sequestration* (Dec. 4, 2009), http://www.netl.doe.gov/publications/press/2009/09081-Secretary_Chu_Announces_CCS_Invest.html (last visited Dec. 30, 2010).
51. *Id.*
52. *Id.*
53. Lynn Garner, *Obama Establishes Interagency Task Force to Expedite Carbon Capture at Power Plants,* 41 Env't Rep. (BNA) 263 (Feb. 5, 2010).
54. IOGCC. *Storage of Carbon Dioxide in Geologic Structures: A Legal and Regulatory Guide for States and Provinces* 10 (2007).
55. Victor B. Flatt, *Paving the Legal Path for Carbon Sequestration From Coal,* 19 Duke Envtl L. & Pol'y F. 211, 231 (2009).
56. 15 U.S.C. §717.
57. Flatt, *supra* note 55, at 237 (citing Elizabeth J. Wilson & Mark A. de Figueiredo, *Geologic Carbon Dioxide Sequestration: An Analysis of Subsurface Property Law*, 36 ELR 10114, 10116-18 (Feb. 2006)).
58. *See, e.g.*, IOGCC, Strategic Plan: The Domestic Resource, http://www.iogcc.state.ok.us/strategic-plan (last visited Sept. 23, 2010).
59. *See* IOGCC. States Are Best Positioned to Regulate Carbon Dioxide Storage, Report Concludes. IOGCC Press Release (Sept. 26, 2007), *available at* http://www.iogcc.state.ok.us/states-are-best-positioned-to-regulate-carbon-dioxide-storage-report-concludes.
60. *See generally* Kirsten H. Engel, *Mitigating Global Climate Change in the United States: A Regional Approach*, 14 N.Y.U. Envtl. L.J. 54 (2005).

Regional Greenhouse Gas Initiative (RGGI), has quarterly allowance auctions that have raised over $729 million.

Each of the three regional groups takes a different stance on how CCS will fit into its system. Recently, these regional groups have collaborated on policy and may be looking for broader influence on national solutions by adopting common approaches to dealing with GHGs and cap-and-trade regulations.[61] The material that follows discusses these regional developments, but whether these efforts survive is unknown. Federal legislation like the U.S. House of Representatives-passed H.R. 2454 would block the use of state or regional programs from 2012 to 2017, even if the federal program does not begin in 2012, as called for in the legislation. The U.S. Senate Bill 1733 also includes a moratorium on sub-national programs during 2012 to 2017, but it allows existing programs to continue until nine months after the first auction of federal allowances.[62] But while federal legislation has stalled during 2010, the regional groups are pushing forward to establish policy and organize actual and projected GHG auctions.[63]

A. Regional Programs—the IOGCC

While the IOGCC's main mission is to help states develop regulatory policies to maximize their oil and gas resources, it established a task force on carbon storage because of member states' interest in "the most immediate and viable strategies available for mitigating the release of CO_2 into the atmosphere."[64] The resulting guide, issued in 2007, derived from the task force's conclusion that states had the best experience, expertise, and jurisdiction to regulate CCS.[65] The IOGCC emphasizes state control rather than a regional approach, and the guide suggests legal regulations for CCS to facilitate and protect state interests.

The IOGCC defines CO_2 as "anthropogenically sourced carbon dioxide of sufficient purity and quality as to not compromise the safety and efficiency of the reservoir to effectively contain carbon dioxide."[66] This definition is less precise than its previous definition, requiring 95% purity, to allow for "evolving capture technologies and new research regarding reservoir storage capabilities."[67] While the IOGCC does not directly address legal issues associated with a cap-and-trade program, it does recommend that any regulatory frameworks for emissions trading should use the regulatory experience of the states, especially for natural gas and underground storage. Based on its analysis of states' experience with property rights, resource management, and tort issues such as trespass and damages, the IOGCC makes the following recommendations related to CCS:

- State oil and gas regulatory agencies are the most logical and best equipped agencies to implement rules and regulations for CCS;
- CO_2 should be regulated as a resource rather than a waste or pollutant to allow beneficial uses;
  - As part of this paradigm, IOGCC emphasizes that CCS is an economic solution rather than just a regulatory necessity;
  - But, IOGCC also recommends a cradle to grave regulatory framework for CCS, much like that used for hazardous waste by EPA;
- Control of long-term underground carbon storage rights should be a required part of site licensing for CCS and be under state control;
- Long-term storage rights should also include eminent domain or unitization powers to allow control of the entire storage reservoir;
- States should develop a two-stage closure process made up of an initial closure period, with liability still attached to the project manager, and a long-term post-closure period, with liability shifting to a state trust;
  - States must have the power to implement needed monitoring, verification, and remediation regulations in the post-closure phase;
- States, rather than EPA, should regulate the post-operational phase of storage.[68]

With its main goal of protecting property rights, the IOGCC advocates maintaining the status quo for regulation of CO_2 injections for EOR, which means the right to inject CO_2 is a property right, governed by the oil and gas lease. Only when active oil production has ceased and injection is for the distinct purpose of long-term storage would storage rights move into new regulatory territory. The IOGCC recommends the state enter at this point to control long-term storage. If underground storage is a property right and carbon is a resource rather than a waste product, state laws and lease interpretations are the logical legal pathways for regulation.

While the IOGCC is not focused on combating climate change, it raises important federalism issues that should be considered in any approach to regulating CO_2 and underground storage. However, issues of patchwork regulations, financing, developing infrastructure, freeriders and cost-sharing, business migration, and environmental justice

61. *See* Three-Regions Offsets Working Group, *Ensuring Offset Quality: Design and Implementation Criteria for a High-Quality Offset Program*, May 2010, *available at* http://www.midwesternaccord.org/News%20Page/Three-Regions_Offsets_Whitepaper%2005_17_10.pdf.
62. *Senate Brokers Climate Preemption Compromise,* XX Clean Air Rep. (Inside EPA) 21:36 (Oct. 15, 2009).
63. *See, e.g.*, Plan B—Going It Alone: Regional Programs in North America, Point Carbon (Feb. 25, 2010), *available at* http://www.pointcarbon.com/research/cmana/cmana/1.1416963; Brian J. Donovan. Regional Greenhouse Gas Cap-and-Trade Programs May Be the Solution. The Donovan Law Group, Apr. 5, 2010, *available at* http://donovanlawgroup.wordpress.com/2010/04/05/regional-greenhouse-gas-cap-and-trade-programs-may-be-the-solution/.
64. IOGCC, CO_2 Storage: A Legal and Regulatory Guide for States (Dec. 2007), *availableat*http://groundwork.iogcc.org/topics-index/carbon-sequestration/executive-white-papers/co2-storage-a-legal-and-regulatory-guide-fo.
65. *Id.* at 3.
66. *Id.* at 32.
67. *Id.* at 24.
68. *Id.* at 10-12.

involve interstate issues that would benefit from a regional or national approach. The three programs discussed below are attempting to affect and control climate change from a regional perspective. But before discussing the individual programs, initial collaborative efforts between the three programs are introduced.

B. Regional Programs—Three-Regions Collaborative Process

There is speculation that because federal legislation seems to have stalled, the three regional programs will link together to pressure and incentivize other states to adopt climate change strategies.[69] Collaboration between the three regional programs, however, has been limited. A white paper on offsets has been developed that provides common definitions and review processes.[70] It defines offsets and lays out minimum requirements an offset must meet to qualify for allowance credit under any of the three regional cap-and-trade programs. According to the document, an offset is "a project-based greenhouse gas emissions reduction or removal that occurs outside the capped emissions sector or sectors regulated by the cap-and-trade program."[71] To earn allowances for a regulated entity, each offset must meet the outlined standards to show it is real, additional, verifiable, permanent, and enforceable. These requirements and definition bring more clarity to the concept of offsets, which had somewhat different definitions and requirements under the three separate programs.

C. Regional Programs—the RGGI

Ten northeastern and midatlantic states that are part of the RGGI[72] seek to reduce carbon emissions through a cap-and-trade "Budget Trading Program" imposed on the region's fossil-fueled electric-generating facilities that have the capacity to produce 25 MW or more of energy.[73] The program seeks to stabilize CO_2 emissions at 2009 levels until 2014 and then gradually reduce emissions 2.5% per year to reach a 10% reduction by 2018.[74] On December 20, 2005, the RGGI became the first mandatory regional GHG program.[75] The RGGI program does not attempt to regulate GHGs other than CO_2, although it allows offset projects for methane and sulfur hexafloride. The RGGI is implemented by each of the 10 member states: Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont.[76] Pennsylvania refused to join the RGGI, because of concerns that a cap-and-trade program aimed at power plants will increase emissions as power distributors purchase lower cost out-of-state power.[77] Each state is to implement a CO_2 control program using the RGGI Model Rule (Model Rule)[78] as a guide to state regulation, and each state is to designate a state regulatory agency, typically the Department of Environmental Quality, to administer the program.[79] On March 18, 2011, the New Hampshire House of Representatives voted to withdraw from the RGGI cap-and-trade program. The New Hampshire Senate is expected to do the same.

The RGGI program approval was aided by the fact that all of the involved states were at various stages of developing a CO_2 control program. New Jersey was the first state to develop a GHG reductions plan aimed at reducing CO_2 by 3.5% by 2005.[80] On April 20, 2007, Maryland became the last state to formally join the RGGI.[81] Each state establishes emission limits for electric power plants, creates CO_2 allowances, and determines appropriate allocations. The state regulations may be found on the RGGI website.[82]

The 10 participating states agreed to stabilize emissions from electric power plants at the 2009 level of 188 million tons per year until 2014 and to reduce CO_2 by 2.5% per year for four years beginning in 2015.[83] Each regulated electric power plant received a cap and must hold enough allowances to cover its emissions. The states retain at least 25% of their total allowances to sell to power plants and use the money for programs that promote energy efficiency, energy conservation, or to provide rebates to consumers. These goals were seen as relatively modest when the program began, and since they were set, a nationwide recession and falling natural gas prices have already led to a 34% reduction in regional emissions. Thus, under the current cap goals, most sources will reach their final reduction goals without having to make any additional changes.[84]

The RGGI Model Rule allows emission sources to invest in CO_2 offset projects and deduct the resulting sequestered or avoided CO_2 from their total emissions for the year.[85] While the definition and regulation of offsets has been updated by the Tri-Regional white paper, the Model Rule provides more specific guidelines for the amount and type of offsets regulated entities can use. Power plants may offset up to 3.3% of their GHG emissions.[86] However, the Model

69. Nathanial Gronewold, *RGGI Gathering May Be First Step Toward Trading Revisions*, Env't & Energy Pub., Aug. 25, 2010.
70. RGGI, Midwestern Regional Greenhouse Gas Reduction Accord (MGGA), & Western Climate Initiative (WCI), Ensuring Offset Quality: Design and Implementation for a High-Quality Offset Program (May 2010), *available at* http://www.westernclimateinitiative.org/component/remository/general/Ensuring-Offset-Quality-Design-and-Implementation-Criteria-for-a-High-Quality-Offset-Program/ [hereinafter Tri-Regional Offsets].
71. *Id*. at 6.
72. RGGI, About RGGI, http://www.rggi.org/about (last visited Dec. 30, 2010).
73. RGGI, RGGI Model Rule, at 20, http://www.rggi.org/design/history/model_rule (last visited Dec. 30, 2010) [hereinafter RGGI Model Rule].
74. RGGI, RGGI Fact Sheet, http://www.rggi.org/design/fact_sheets (last visited Dec. 30, 2010) [hereinafter RGGI Fact Sheet].
75. *Id.*
76. XIX Clean Air Report (Inside EPA) 1:24 (Jan. 10, 2008).
77. Dean Scott, *Concerns Over Potential Emissions "Leakage" Keep Pennsylvania Out of Regional Initiative*, 39 Env't Rep. (BNA) 263 (Feb. 8, 2008).
78. *See generally* RGGI, Model Rule, *supra* note 73.
79. RGGI, Participating States, http://www.rggi.org/states (last visited Dec. 30, 2010).
80. *Id.*
81. *See* http://www.rggi.org/design/regulations (last visited Dec. 30, 2010).
82. *See* http://www.rggi.org/design/regulations (last visited Dec. 30, 2010).
83. Martha Kessler, *Connecticut Official Says States Not Ready to Cede Role in Developing Climate Policy,* 39 Env't Rep. (BNA) 2355 (Nov. 28, 2008).
84. *See* Gronewold, *supra* note 69.
85. *See generally* RGGI Model Rule, *supra* note 73, subpt. xx-10.
86. *Id.* xx- 6.5(a)(3)(i).

Rule provides that if the market prices for an allowance exceed $7.00 in 2005 dollars[87] the percentage of allowable offset deductions is raised to 5%,[88] and if the price of an allowance exceeds $10.00 in 2005 dollars,[89] the percentage of allowable offset deductions is raised to 10%.[90] As of December 28, 2010, allowances were available for $1.86, making the possibility of additional offsets remote.[91]

The Model Rule recognizes five offset projects: (1) landfill methane capture and destruction; (2) reduction in emissions of sulfur hexafluoride; (3) sequestration of carbon due to afforestation; (4) reduction or avoidance of CO_2 emissions from natural gas, oil, or propane end-use combustion due to end-use energy efficiency; and (5) avoided methane emissions from agricultural manure management operations.[92] The only sequestration of CO_2 allowed under the RGGI is the biological sequestration of carbon in trees through the afforestation process. The RGGI program does not address geological storage.

The RGGI program was challenged in New York by a natural gas-fired cogeneration plant, seeking to overturn the state's regulations that implement the RGGI.[93] The lawsuit claimed the RGGI violated the Compact Clause of the U.S. Constitution, and that the cap-and-trade program was an impermissible tax that was not authorized by the state legislature. However, the major concern of the litigant was that it would not be able to pass the cost on to the buyer of its electricity as other providers could, because it has a long-term fixed price contract with Consolidated Edison (Con Edison).[94] The parties reached a settlement agreement in December 2009, which preserved New York's participation in the RGGI by negotiating a way for Indeck Corinth to recover the costs of CO_2 allowances.

> Under the terms of the settlement, Con Edison will pay the cogeneration plants for costs they incur in purchasing CO_2 emissions allowances at RGGI auctions. The state, in turn, will essentially reimburse Con Edison by making about $2.6 million in annual investments in the company's infrastructure and smart grid technologies.[95]

Thus, the court never ruled on the constitutional legitimacy of the RGGI, but the cogeneration plant is participating in the cap-and-trade program through concessions from the state and its electricity purchaser.

RGGI CO_2 auctions produced $729 million in nine auctions over two years. According to regulatory documents, and about two-thirds of the money should be invested in energy-efficiency and alternative-energy technologies, which would reduce the need for CCS. However, in 2009, both New Jersey and New York used $155 million from these funds to reduce their deficits, and despite specific funding requirements in RGGI documents, it does not appear that the RGGI has any legal authority over how states use their funds.[96] The clearing price for allowances sold in the June 2010 auction was $1.86, down from the initial price of $3.07 and a high of $3.51 in March 2009. Ninety-two percent of the allowances for immediate use and all the allowances for use after 2013 were purchased by electric power generators.[97] After the recession lowered demand for electricity, sales of allowances went down 33% from 2005 compared to 2009. Besides the recession, lower demand for electricity was attributed to increased use of nuclear and wind-generated power, and fuel-switching due to lower natural gas prices.[98] The market for allowances has collapsed, and the Chicago Climate Exchange ended GHG allowance trading at the end of 2010.[99]

D. Midwestern Regional Greenhouse Gas Reduction Accord (MGGA)

On November 15, 2007, nine governors of midwestern states and the Premier of Manitoba signed the MGGA.[100] The states now participating are Illinois, Iowa, Kansas, Michigan, Minnesota, South Dakota, and Wisconsin, as well as Manitoba. Indiana, Ohio, and Ontario are participating as observers. Nebraska and North Dakota are cooperating with the Accord states in regional initiatives to address climate change. The MGGA states seek to reduce GHG emissions through a regional cap-and-trade system and complementary policies that encourage regional development of renewable energy, energy efficiency, biofuels, and carbon capture and storage.[101] In addition, the MGGA has established GHG reduction targets and time frames consistent with member states' targets. It has also established tracking, management, and crediting systems, and more than any other regional group, MGGA has embraced CCS as an important and effective regional resource for

87. *Id.* xx-1.2(b)(j).
88. *Id.* xx 6.5(a)(3)(ii).
89. *Id.* xx-1.2(b)(l).
90. *Id.* xx-6.5(a)(3)(iii).
91. *See* RGGI website, http://www.rggi.org/home.
92. RGGI Model Rule, *supra* note 73, subpt. xx-10.3(a)(1)(i)-(v).
93. Indeck Corinth, L.P. v. Paterson, Case No. 2009 369, RJI No. 2009/0369 (N.Y. Sup. Ct.).
94. Gerald B. Silverman, *Cogeneration Plant Sues New York to Overturn State's RGGI Regulations,* 40 Env't Rep. (BNA) 302 (Feb. 6, 2009); Gerald Silverman, *State Agency Approves Spending Plan for Proceeds From RGGI Allowance Auction*, 40 Env't Rep. (BNA) 1023 (May 1, 2009). *See also* http://www.nyserdarg/RGGI/default.asp (last visited Dec. 30, 2010).
95. Gerald B. Silverman. *State Settles Lawsuit With Plant Owners That Challenged Implementation of RGGI*, 41 Env't Rep. (BNA) 36 (Jan. 1, 2010).
96. *See* Steve Jones. *Preemption of Regional Climate Compacts: A Hot Topic in the Global Warming Debate*, 2010 Emerging Issues 5016 (May 6, 2010); *Environmentalists to Push RGGI Expansion During Program Review*, Carbon News (Aug. 30, 2010).
97. *See* RGGI, Auction Results, *available at* http://rggi.org/home (last visited Dec. 30, 2010); Gerald B. Silverman, *Regional Initiative Carbon Allowances Sell for $1.88 Each in Eighth Auction,* 41 Env't Rep. (BNA) 1357 (June 18, 2010).
98. Gerald B. Silverman, *Report Says Carbon Dioxide Emissions Fell by 60.7 Million Tons in RGGI States,* 41 Env't Rep. (BNA) 2512 (Nov. 12, 2010); Gerald B. Silverman, *RGGI Sells Carbon Dioxide Allowances for $1.86 Each, Raises $66.4 Million,* 41 Env't Rep. (BNA) 2064 (Sept. 17, 2010).
99. Leora Falk, *Chicago Climate Exchange to Halt Trading at Year's End, Will Become Offset Registry,* 41 Env't Rep. (BNA) 2406 (Oct. 29, 2010).
100. *See* http://www.midwesternaccord.org (last visited Dec. 30, 2010).
101. *See* MGA, Midwestern Energy Security and Climate Stewardship Roadmap (2009), http://www.midwesterngovernors.org/publications.htm (last visited Sept. 29, 2010).

reducing carbon emissions.[102] It developed specific carbon storage goals, paths to commercialization, and legal and regulatory models to encourage both more carbon capture and state policies to facilitate the infrastructure needed for transportation and storage of CO_2.[103] One of the most important methods for making CCS an economically viable technology, the MGGA cap-and-trade program is scheduled to begin in January 2012, with a final model rule released in April 2010.[104]

The 2007 MGGA document does not specifically mention geologic carbon sequestration or geologic storage, but the *Energy Security and Climate Stewardship Platform for the Midwest* (MGA Platform) that was released by the Midwestern Governors Association (MGA) to accompany the 2007 Accord has as its third listed objective to "(i)mplement geologic CO_2 storage, terrestrial carbon sequestration and other technological utilization of CO_2 on a large scale."[105] To fulfill the carbon sequestration objective, the MGA Platform seeks as a key strategy to "(a)ccelerate the commercialization of advanced coal and natural gas technologies and infrastructure for the capture and geologic storage of CO_2 emissions, including for enhanced oil and gas recovery."[106]

The MGA Platform enumerates specific goals and measures, and a "Cooperative Regional Initiative" specifies how member states are to achieve their carbon sequestration goals.[107] In fulfillment of one of these goals, the MGA released a regulatory "Toolkit" in 2009, providing a regulatory framework to enable permanent geologic storage and clear direction to allow for CO_2 capture, injection, monitoring, verification, and compliance, and address liability for stored CO_2.[108] The MGA Toolkit suggests statutory and regulatory actions states can take to promote CCS, broken down by issues related to transport, ownership, and liability and financial responsibility. The Toolkit is based on the IOGCC's regulatory framework and World Resources Institute CCS guidelines, as well as a regional survey of state statutes and regulations. Key markers for the MGA Platform include siting and permitting for a multijurisdictional pipeline by 2012 to transport CO_2 from power plants to a reservoir for use in enhanced oil and gas recovery. By 2012, the region should also have at least one commercial-scale IGCC power plant using bituminous coal that uses CCS. By 2015, the region plans to have three or more commercial-scale IGCC plants with CCS that use bituminous coal, at least one IGCC plant with CCS that uses sub-bituminous coal, at least one plant with CCS that uses lignite coal, and one or more pulverized coal plants that use commercial-scale post-combustion CO_2 capture of emissions. By 2020, all new coal gasification and coal-combustion plants are to capture and store CO_2 emissions, and by 2050, the region's fleet of coal plants will have transitioned to CCS.[109]

A 2009 Roadmap laid out four priorities for regional development of advanced coal and CCS.[110] The first priority, to develop a legal and regulatory framework for CCS, was fulfilled by release of the Toolkit and Inventory. States may now modify Toolkit models to fit their own situations. The second priority is to lay the groundwork for a Geologic Storage Utility. A Geologic Storage Utility would serve some of the same functions as the IOGCC state trust discussed above, such as taking long-term responsibility for stored CO_2 and assuring that an entire storage reservoir is under a single managing entity. But the MGA plan envisions an even broader role.

> Such a utility could facilitate the development of the commercial CCS industry in the region by taking responsibility for the planning, development, financing, management and long-term site stewardship associated with multiple projects developed in storage formations such as deep saline formations that may cross jurisdictional boundaries. Centralized coordination of such projects would reduce the complexity of managing multiple geologic storage projects in the same geologic formation and provide certainty and transparency to accelerate scale-up of the industry.[111]

The MGA Commercial Plan also identifies establishment of a Geologic Storage Utility as an important assurance for CCS developers, because it will provide a "more stable and predictable environment" as well as relieving long-term liability concerns.[112]

The Roadmap's third CCS priority is to use the long-term experience and commercial nature of EOR to incentivize CO_2 storage. Both the Roadmap and Commercial Plan emphasize EOR as the best pathway to develop the necessary technology, funding, and legal framework for large-scale, commercial CCS.[113] The Natural Resources Defense Council also sees the integration of CCS and EOR as a positive development for reducing GHGs: "CO_2-EOR has a substantial immediate to long-term role to play in both increasing domestic oil production in a responsible way, and in sequestering CO_2 underground. Policies that incentivize the capture of industrial CO_2 can help the

102. *See* MGGA, Final Model Rule for the Midwestern Greenhouse Gas Reduction Accord, April 2010, http://www.midwesternaccord.org/ (last visited Sept. 29, 2010) [hereinafter MGGA Model Rule].

103. *See* MGGA, Advisory Group Final Recommendations, May 2010, http://www.midwesternaccord.org/ (last visited Dec. 30, 2010); Midwestern Governors Association (MGA); MGA, Regional Commercial Plan for Carbon Capture and Storage, Sept. 2009, http://www.midwesterngovernors.org/energy.htm (last visited Dec. 30, 2010) [hereinafter MGA Commercial Plan]; MGA, Legal and Regulatory Inventory for Carbon Capture and Storage & Analogues, Mar. 2009, http://www.midwesterngovernors.org/energy.htm (last visited Dec. 30, 2010) [hereinafter MGA Inventory]; MGA, Toolkit for Carbon Capture and Storage: Statutory and Regulatory Issues, Mar, 2009, http://www.midwesterngovernors.org/energy.htm (last visited Dec. 30, 2010) [hereinafter MGA Toolkit].

104. MGGA Model Rule, *supra* note 102.

105. MGA, Energy Security and Climate Stewardship Platform for the Midwest, at 4 (2007) [hereinafter MGA Platform].

106. *Id.* at 5.

107. *Id.* at 18-27.

108. MGA Toolkit, *supra* note 103, at 4.

109. MGA Platform, *supra* note 105, at 18.

110. MGA, Midwestern Energy Security and Climate Stewardship Roadmap (2009), http://www.midwesterngovernors.org/energy.htm (last visited Dec. 30, 2010) [hereinafter MGA Roadmap].

111. *Id.* ix.

112. MGA Commercial Plan, *supra* note 103, at 6, 12.

113. *See id.* at 9; MGA Roadmap, *supra* note 110, ix.

country access an untapped domestic oil resource while reducing global warming pollution."[114]

The MGA Platform recommends that states and industry assist existing small to medium oil and gas producers in finding EOR methods that are cost effective.[115] States should support comprehensive assessments of geologic reservoirs at the state and federal levels to determine the CO_2 storage potential and feasibility. The Commercial Plan outlines two phases to expand CCS commercially: Phase I (through 2015) develops commercial-scale capture projects and associated infrastructure related to EOR projects in Kansas, Manitoba, Michigan, Missouri, and North Dakota. It also develops a CO_2 pipeline to connect capture projects in Illinois, Indiana, Kentucky, and Ohio to Gulf Coast EOR projects. Phase II (2015-2025) expands the pipeline network and connects all midwestern jurisdictions by pipeline, so that states lacking geologic storage capacity can still capture CO_2 and transport it to other midwestern states for storage.[116] The MGA recommends funding large-scale geologic storage tests to assist in developing commercial storage capability.[117] Member states can evaluate the feasibility of CO_2 transport and advanced sequestration to assist jurisdictions without geologic storage potential.[118]

The Roadmap's fourth priority is to reduce capital costs of CCS projects and pipelines. The MGA Platform provides suggestions for financial and regulatory incentives to build advanced coal-generation projects with CCS.[119] For example, states should enact state tax incentives for front-ended engineering and design studies for power plant costs.[120] States should match the Energy Policy Act of 2005 plant development incentives and should assure cost recovery for approved advanced coal projects that use CCS technology.[121] States should encourage low-CO_2 coal technologies and modify state policies and regulatory programs to favor advanced-generation technologies that limit CO_2 emissions and use CCS to replace conventional pulverized coal units.[122] The MGA Platform lists several specific means to achieve this goal, including, inter alia, requiring a low-carbon electricity portfolio standard, a CCS portfolio standard, and market-based regulatory programs to encourage investment in low-carbon technologies.[123] It also advocates incentives for deployment of innovative coal gasification technologies, including co-gasification of biomass and underground coal gasification, and the utilization of captured CO_2.[124]

To support advanced coal and CCS technology, the member states made specific resolutions.[125] Several of these resolutions have now been fulfilled.

1. Quantify the potential costs and benefits of EOR: This resolution was at least partly fulfilled by an Advanced Resources International report submitted to the MGA in June 2009. It examines the technical and economic potential of EOR, using CO_2 in eight of the 12 midwestern states.[126]

2. Expand assessment of geologic reservoirs for CO_2 storage in Partnership states that lack oil- and gas-bearing formations known to be suitable for CO_2 injection and storage, notably Minnesota and Wisconsin.

3. Produce a state-by-state inventory of Partnership member's regulations governing or potentially relating to CO_2 capture, compression, pipeline transportation, and underground injection. This resolution was fulfilled by the MGA Inventory discussed above.[127]

4. Develop a uniform regional model state regulatory framework specific to CO_2 capture, compression, pipeline transport, and underground injection and storage, informed by emerging federal approaches and the draft Interstate Oil and Gas Commission regulations: This resolution was fulfilled by the MGA Toolkit discussed above. The MGA's most recent meeting discussed ways to implement this framework either state-by-state or regionally.[128]

5. Study and propose a regional pipeline system serving more than one Partnership member (and possibly connecting Partnership members with other regions) that links one or more sources of captured CO_2 with appropriate geologic reservoirs (e.g., Illinois Basin and Michigan, Ohio, and Northern Plains EOR formations) and injection and storage facility for EOR and deep saline aquifer storage: While the pipeline system has been proposed, there is still much more work to be done before it can be actualized.[129]

6. Create a Partnership-wide commercial plan for CO_2 management that incorporates the above elements and emphasizes EOR as an important step toward deep saline aquifer CO_2 storage: This resolution was fulfilled by the MGA Commercial Plan.

114. Natural Resources Defense Council, Tapping Into Stranded Domestic Oil: Enhanced Oil Recovery With Carbon Dioxide Is a Win-Win-Win, July 2008, *available at* http://www.nrdc.org/energy/eor.pdf.
115. MGA Platform, *supra* note 105, at 20.
116. MGA Commercial Plan, *supra* note 103, at 7-8.
117. MGA Platform, *supra* note 105, at 20.
118. *Id.*
119. *Id.* at 22.
120. *Id.* at 23.
121. *Id.*
122. *Id.*
123. *Id.*
124. *Id.* at 25.
125. *Id.* at 27.
126. MGA, CO_2-Enhanced Oil Recovery Potential for the MGA Region (June 2009), http://www.midwesterngovernors.org/energy.htm (last visited Dec. 30, 2010).
127. *See* MGA Inventory, *supra* note 103.
128. MGA, Carbon Capture and Storage Task Force: Meeting One Notes, Columbus, Ohio, Aug. 25-26, 2010, http://www.midwesterngovernors.org/CCS.htm (last visited Dec.30, 2010).
129. *See* MGA Commercial Plan, *supra* note 103, at 7 (showing map of proposed pipeline systems).

7. Coordinate the Partnership's FY 2009 request for federal investment in CO_2 capture and storage infrastructure in the MGA region.

In May 2010, the MGGA's Advisory Group Final Recommendations (Final Recommendations) were released.[130] The Final Recommendations do not directly discuss CCS, but the broader workings of the program, combined with the above MGA initiatives, identify the role CCS may play in the implementation of the MGGA.

The Final Recommendations recommend reducing emissions of the six GHGs 20% below 2005 levels by 2020, and 80% below 2005 levels by 2050. These goals are subject to revision and updates based on technology and program results.[131] The first deliverer of electricity,[132] industrial combustion sources, and the final blender or distributor of transportation or other residential, commercial, or industrial combustion fuels ("covered sectors") are the regulatory targets.[133] Entities with annual emissions greater than 25,000 metric tons, calculated on a three-year rolling average, will be subject to the program. If emissions from any source drop below 25,000 metric tons for a three-year period, that source can apply for exemption from the program.[134] Electric units generating less than 25 MW of energy or that are fueled using 100% biomass are exempt from regulation. Entities in the covered sectors producing more than an annual equivalent of 20,000 metric tons of CO_2 must begin collecting GHG emission data in January 2010, and begin reporting emissions to the Climate Registry Information System[135] in 2011.[136] The MGGA is to become effective January 2012.[137]

Each participating jurisdiction[138] is responsible for implementing, regulating, and enforcing the provisions of the MGGA's cap-and-trade program and must create an accounting system for allowances and/or offsets.[139] Each regulated entity will demonstrate compliance by surrendering allowances matching their emissions to the appropriate state regulatory agency[140] or surrender penalty allowances or pay a fee for every metric ton of CO_2 equivalent (CO_2e) not accounted for.[141] States may also levy additional penalties and fees.[142] Regulated entities will make public all emission records that are not subject to confidentiality.[143] The Final Recommendations also recommend that each jurisdiction establish market oversight rules to promote sound markets and prevent fraud.[144] These rules should be "a flexible and adaptive cost containment framework that includes a desired trading price range," stability, avoidance of market failure triggers, and "orderly operation of the allowance trading market."[145] The Final Recommendations also recommend linking the MGGA to other GHG reduction programs, including the RGGI, the Western Climate Initiative, and the European Emission Trading System.[146]

The Final Recommendations recommend dividing the regional cap between participating states based primarily on their relative emissions.[147] However, the Final Recommendations also provide room for some of the allowance budget to be apportioned using other criteria, like emissions per capita, population and economic growth, or new and projected emission sources.[148] Proceeds from allowances are to be used solely for climate change purposes.[149] Funds should be used for: (1) accelerating transformational investments, like the IGCC, CCS, and low-carbon technologies recognized in the MGA Platform; (2) mitigating transitional adverse impacts of the program; and (3) addressing harmful impacts due to climate change.[150]

The MGGA envisions each jurisdiction deciding how and whether to allocate or auction allowances, but the Final Recommendations recommend general and specific allowance distribution mechanisms. On the general side, it is recommended that each participating jurisdiction: (1) annually place 2% of their allowances in a reserve pool for cost containment to prevent excessively high or low allowance prices[151]; (2) enact strong legal mechanisms safeguarding allowance value, ensuring that allowance profits are used for climate purposes, that the distribution is transparent, and that market manipulation and speculation are minimized[152]; and (3) create mechanisms that prevent windfall profits.[153]

On the more specific side, the Final Recommendations recommend a hybrid distribution method that would, for the first three-year compliance period, auction some of the allowances and allocate the rest.[154] Under this method, a set percentage of the total regional allowances, a suggested 5%, would be auctioned regionally and the proceeds directed to regional programs, like the Low-Carbon

130. MGA. Advisory Group Final Recommendations (2010), http://www.midwesternaccord.org (last visited Dec. 30, 2010) [hereinafter MGA Final Recommendations].
131. *Id.* at Recommendation 1.1.
132. For electricity produced and sold within a participating jurisdiction, the first deliverer is the generator of the electricity; for electricity generated outside a jurisdiction but sold inside a participating jurisdiction, the first deliverer is the entity that first delivers the electricity into the participating jurisdiction. *Id.* at Recommendation 2.4.1.
133. *Id.* at Recommendation 2.4.
134. *Id.* at Recommendation 2.5.
135. *See generally* The Climate Registry, http://www.theclimateregistry.org (last visited Dec. 30, 2010).
136. MGA Final Recommendations, *supra* note 130, at Recommendation 5.0.
137. *Id.* at Recommendation 7.1.
138. The participating jurisdictions are Kansas, Illinois, Iowa, Michigan, Minnesota, and Wisconsin, and Manitoba. *Id.* at Introduction.
139. *Id.* at Recommendation 6.1, 6.4 & 5.
140. *Id.* at Recommendation 6.2.
141. *Id.* at Recommendation 6.3.
142. *Id.* at Recommendation 6.3.
143. *Id.*
144. *Id.* at Recommendation 8.1.
145. *Id.* at Recommendation 8.2.
146. *Id.* at Recommendation 2.8.
147. *Id.* at Recommendation 3.1.
148. *Id.*
149. *Id.* at Recommendation 3.3.
150. *Id*. *See also* Recommendations 3.3.1 et seq. (specific means of Transformational Investment like retooling the midwestern manufacturing industry, costs to end uses like low-income consumers and energy-intensive industries, cap-and-trade program costs, and worker training and educational programs).
151. *Id.* at Recommendation 3.5.1.
152. *Id.* at Recommendation 3.5.2.
153. *Id.* at Recommendation 3.5.3.
154. *Id.* at Recommendation 3.5.4.

Technology Commercialization Fund.[155] Complementing the regional auction, it is recommended that jurisdictions attach a modest fee to the remaining allowances and allocate them between the transportation, utility, merchant power, and industrial sectors in proportion to their GHG emissions, without discriminating against combined heat and power. It is also recommended that all allowances for the industrial sector be allocated rather than auctioned for the first two compliance periods, and then gradually transitioned to full action in line with all the other allowances.[156] The Final Recommendations suggest that after the initial three compliance periods, the states transition to a full auction system.[157]

Like the Tri-Regional Offset recommendations, the MGGA Final Recommendations suggest that each jurisdiction develop a carbon offset program that is "real, additional, verifiable, permanent, and enforceable."[158] To make these programs effective, offsets should be regionally reviewed and approved. Material on offset protocols and criteria that was present in the draft of the Final Recommendations was removed from the final version. The Tri-Regional Offsets white paper was produced during this time, and it contains information on offset protocols and criteria that has now been adopted by the MGGA.[159] Collaboration with the other regions on offsets furthers MGGA's goal outlined in the draft materials to standardize offset protocols and criteria as much as possible.

The Midwest Regional Sequestration Partnership announced on October 21, 2009, that it had successfully injected 1,000 tons of liquefied CO_2 into rock beneath the Duke Energy's East Bend Generating Station in Boone County, Kentucky. The partnership expects to inject 1 million tons of CO_2 into the Mount Simon Sandstone formation that lies beneath parts of Illinois, Iowa, Kentucky, Michigan, Missouri, Ohio, and Wisconsin.[160]

E. *Western Climate Initiative*

On February 26, 2007, the governors of Arizona, California, New Mexico, Oregon, and Washington signed the Western Climate Initiative (WCI) to develop regional strategies to address climate change. Subsequently, Montana, Utah, and the Canadian provinces of British Columbia, Manitoba, Ontario, and Quebec joined. In addition, 14 U.S. and Mexican states and the Canadian provinces of Nova Scotia and Saskatchewan are official observers.[161] The WCI is a nonenforceable agreement that does not create binding legal obligations. The parties expect the WCI program to be self-enforcing, because its members benefit from mutual collaboration as a method of improving each state's individual GHG control efforts. The WCI set an overall regional goal to reduce GHG emissions to 2005 levels by 2020, which is about a 15% reduction. Each member must voluntarily establish a program to reach the reduction goal that includes controls on stationary and mobile sources. The WCI has designed a market-based cap-and-trade program to achieve the regional reduction goal. As with all WCI initiatives, member participation is discretionary, and at this point, only California is committed to begin on the program start date of January 1, 2012. The WCI agreement does not provide specific goals, but its aim is to have both independent and collaborative efforts by the participating states to develop a regional approach while still respecting "the interests, needs, and circumstances of each jurisdiction."[162] Although it touts the benefits of a cap-and-trade program with a broad scope and geographic coverage, the WCI is willing to accommodate "alternative schedules for implementation."[163]

On July 27, 2010, the WCI released its Design for WCI Regional Cap-and-Trade Program, which is modeled after existing cap-and-trade plans, such as the RGGI, ERA's Acid Rain Program, and the United Kingdom's Emissions Trading Scheme.[164] The WCI will require allowances for any source with emissions greater than 25,000 metric tons per year. It will also require allowances for deliverers of electricity that generate more than 25,000 metric tons per year to produce the delivered energy, and for any fossil fuel supplier within the jurisdiction whose sold fuel in the jurisdiction would emit 25,000 metric tons or more when combusted.[165] The cap-and-trade program will be implemented in two phases: Phase I starts in 2012, and will cover emissions from electricity, electricity imports, industrial combustion at large sources, and industrial process emissions for which adequate measurement methods exist. Phase II will begin in 2015, and will expand to include transportation fuels and residential, commercial, and industrial fuels not covered in the first phase.

The WCI plan has the broadest scope for targeted sources of the three regional programs. The WCI reasons that the more sources covered by the program, the more opportunities there are for reductions, which should improve program efficiency and reduce compliance costs. The WCI is also developing "complementary policies" outside of the cap-and-trade program to further reduce emissions. The most comprehensive policy is to set Low Carbon Fuel Standards (LCFS) for vehicles. This has already been

155. *Id.* at Recommendation 3.5.4.1.
156. *Id.* at Recommendation 3.5.4.2.1-4 (see individual sections, for more specific restrictions and criteria for each sector).
157. *Id.* at Recommendation 3.5, 3.6 & 4.3.
158. *Id.* at Recommendation 4.1, 4.2 (defining real, additional, verifiable, permanent, enforceable).
159. *See* Tri-Regional Offsets, *supra* note 70.
160. Leora Falk, *Regional Partnership Successfully Injects Carbon Dioxide Underground in Test Project*, 40 Env't Rep. (BNA) 2454 (Oct. 23, 2009).
161. *See* http://westernclimateinitiative.org (last visited Dec. 30, 2010); Peter Menyasz, *Quebec Joins Western Climate Initiative, Will Participate in Emissions Trading Scheme,* 39 Env't Rep. (BNA) 800 (Apr. 25, 2008).
162. WCI, Clean Energy: Creating Jobs, Protecting the Environment, http://www.westernclimateinitiative.org (last visited Dec. 30, 2010).
163. WCI, Design for the WCI Regional Cap-and-Trade Program, at 6 (July 2010), *available at* http://www.westernclimateinitiative.org (last visited Dec. 30, 2010) [hereinafter WCI Design].
164. *Id. See also* WCI, Markets Committee Task 6: Auction Design White Paper, 4 (Apr. 14, 2010), http://westernclimateinitiative.org/the-wci-cap-and-trade-program/program-design (last visited Dec. 30, 2010).
165. WCI Design, *supra* note 163, DD-13-14. Eligible biomass emissions do not count toward total CO_2e emissions.

done in California, and Oregon has passed legislation allowing adoption of an LCFS. The plan uses economic assumptions based on no new coal or nuclear energy plants being constructed through 2020.[166]

The WCI program also has the broadest definition of regulated emissions. It will cover emissions of CO_2, methane, nitrous oxide, nitrogen tri-fluoride, perfluorocarbons (PFCs), hydrofluorocarbons (HFCs), and sulfur hexafluoride, in contrast to the RGGI program that covers only CO_2 from the electric power sector. In the first compliance period, about 50% of GHG emissions will be regulated, and in the second period, beginning in 2015, about 90% of the emissions will be regulated. Transportation fuels are the largest source of GHG emissions in the WCI region, although this differs from state to state and province to province.

Although the cap-and-trade program will only be required for sources with annual potential emissions of 25,000 metric tons of CO_2e or more, WCI Partner jurisdictions will require entities and facilities with annual emissions equal to or greater than 10,000 metric tons of CO_2e to report their emissions. California data show the participation and reporting requirements will cover about 94% of the emissions from stationary sources. Although small sources will not be regulated to reduce the costs of administration and to keep the costs of allowances below a projected $25 through 2020, the WCI will most likely regulate small oil and gas sources that can be aggregated by ownership. Decisions are currently being negotiated as to the level of aggregation (field, basin, or jurisdiction) and the reporting threshold (10,000, 25,000, lower, or higher) required to reach the WCI goal to cover a significant portion of emissions with as few facilities and reporting entities as possible.[167] The WCI is also harmonizing its reporting requirements to align with the new EPA GHG reporting requirements that will go into effect in 2011.[168]

Each WCI Partner jurisdiction will calculate its own preliminary annual allowance budget, based on its projected emissions for covered sources in 2012. Estimates should account for new and shutdown sources, as well as voluntary and mandatory emission reductions through 2012. Each jurisdiction should also propose a target rate of decline (ROD) for each year in the compliance period. This preliminary allowance and ROD will be reviewed by the WCI committee for Cap Setting and Allowance Distribution (CSAD), after which the Partner jurisdiction may make recommended changes at its discretion. It is ultimately up to each individual Partner jurisdiction, working in partnership with other jurisdictions and with input from the CSAD committee, to arrive at its own allowance budget and ROD.[169] The WCI recommends that each jurisdiction distribute enough allowances to cover expected emissions for the first year of each compliance period in 2012 and 2015 to ease the transition into the program.[170] There will be an upward adjustment for allowances in 2015, and thereafter, to account for the addition of transportation, residential, and commercial fuels to the cap-and-trade program. The western states and Canadian provinces will each have an emissions reduction goal, but are free to impose greater reduction requirements.

While the WCI cap-and-trade program encourages consistency among Partner jurisdictions, because it is actually a collection of individual state and provincial auctions that are only joined through recognition of other jurisdictions' allowances, it leaves jurisdictions the most discretion to set and distribute allowances, apply offsets, and decide how funds are used of any of the three regional programs. Each WCI Partner jurisdiction will decide how to distribute its allowances to the regulated sources. However, the WCI is developing some mechanisms to prevent leakage of emissions from one Partner jurisdiction to another or from the WCI region to nonregulated regions. For the first compliance period, the WCI recommends a minimum of 10% of the allowance budget be auctioned, increasing to 25% in 2020.[171] The WCI aspires to have a higher percentage of the allowances auctioned, but is concerned over the economic impacts of auctions on industries with competitors not subject to GHG emission controls. The WCI encourages Partner jurisdictions to identify energy-intensive, trade-exposed (EITE) industries that are particularly vulnerable to outside competition and leakage, and suggests that EITEs be given free distribution allowances and benchmarked to keep them competitive with outside providers.[172] For electricity providers outside of the WCI region, the WCI recommends requiring allowances from the First Jurisdictional Deliverer (FJD) to prevent leakage and unfair competition for electricity providers within the WCI.[173]

The money received from auctioned allowances is subject to some general guidance aimed at encouraging GHG reductions, but the Partner jurisdictions have the discretion to use the money as they wish. Once an allowance is obtained, it does not expire, and can be banked. But, if a source has excess emissions, it cannot borrow allowances from future distributions. If a covered entity or facility does not have sufficient allowances to cover its emissions at the end of its compliance period, it will be required to surrender three allowances for every excess metric ton of CO_2e in excess of its compliance obligation within three

166. WCI, Updated Economic Analysis of the WCI Regional Cap-and-Trade Program (July 2010), http://westernclimateinitiative.org/the-wci-cap-and-trade-program (last visited Dec.30, 2010).

167. *See* WCI issue papers for oil and gas, *at* http://westernclimateinitiative.org/component/remository/Reporting-Committee-Documents/Oil-and-Gas-Workgroup/ (Dec. 20, 2010).

168. *See* WCI, Final Essential Requirements for Mandatory Reporting (July 16, 2009), *available at* http://westernclimateinitiative.org/component/remository/Reporting-Committee-Documents/Final-Essential-Requirements-for-Mandatory-Reporting.

169. *See* WCI, Guidance for Developing WCI Partner Jurisdiction Allowance Budgets, (July 8, 2010), *available at* http://westernclimateinitiative.org/wci-committees/cap-setting-a-allowance-distribution-committee.

170. WCI Design, *supra* note 163, at 8-9.

171. *See* WCI, Frequently Asked Questions, http://westernclimateinitiative.org/the-wci-cap-and-trade-program/faq (last visited Dec. 30, 2010).

172. WCI Design, *supra* note 163, at 14.

173. *Id.* at 24.

months after the end of the compliance period. There are no other regional penalties in the WCI Design; instead, each jurisdiction is expected to use its authority to enforce compliance. Because some level of harmonization in stringency and enforcement is necessary, the WCI strongly recommends that all jurisdictions punish excess emissions by requiring one allowance for each ton of excess, plus three additional allowances.[174]

On May 8, 2009, the WCI proposed mandatory reporting requirements for facilities subject to the emissions trading program that are more comprehensive than EPA's reporting requirements.[175] Many energy companies that operate in the West oppose this proposal,[176] but Washington has already proposed rulemaking to implement it.[177] The WCI also proposes creation of a regional administrative organization to coordinate the regional auction of allowances; tracking emissions and providing public information; reporting on market activity; updates between Partner jurisdictions; and review and adoption of protocols and offsets.[178]

An important part of the WCI cap-and-trade program involves offsets. Following the tri-regional approach to defining offsets, the WCI allows the most generous use of offsets of the three regional programs to achieve GHG reductions, reduce compliance costs and encourage technological innovation. The WCI will reward offset certificates to the sponsor of a GHG emissions offset project. A WCI offset certificate is awarded for: "a reduction or removal of one metric ton of CO_2e (tCO_2e). Reductions and removals must be clearly owned, adhere to recommended protocols, and result from a project located in a qualifying geographic area."[179] Offsets are achieved through activities that are often referred to as "offset projects." Offset certificates will be accepted as allowances, subject to limitations (currently recommended as less than 49% of a source's total emissions), and can be used for compliance purposes or as part of voluntary actions. When used within a cap-and-trade program, "offset certificates used for compliance purposes must come from emission sources or sinks not covered by the cap."[180] Each Partner jurisdiction is authorized to issue offset credits for approved GHG reduction projects located in North America. Each Partner jurisdiction must accept offset certificates from other Partner jurisdictions and may elect to accept offset certificates from outside North America if it so chooses. This would allow credits from developing countries, such as those based on the Clean Development Mechanism (CDM) of the Kyoto Protocol, to be accepted.[181]

The WCI has recommended that offsets be used for no more than 49% of total emission reductions, though individual Partner jurisdictions may establish a lower percentage limit if they see fit.[182] Before approving offset projects, Partner jurisdictions are responsible for transparently establishing criteria "such that sufficient and appropriate protocol, project and certificate information is disclosed in a timely manner to allow offset system participants and the general public to make decisions with reasonable confidence."[183] WCI offsets are based on the same criteria as the tri-regional offsets recommendations: real, additional, permanent, verifiable, and enforceable. Partner jurisdictions are responsible to enforce local offset projects by putting sufficient compliance and enforcement mechanisms in place to compel compliance and verify that offsets actually reduce, remove, or avoid GHGs.[184]

Projects within WCI jurisdictions that meet WCI criteria must be recognized by all jurisdictions, regardless of the jurisdiction of origin.[185] Though development of offset projects within WCI jurisdictions is highly encouraged,[186] Partner jurisdictions may also accept offset projects throughout Canada, Mexico, and the United States if projects are subject to comparable rigorous oversight, validation, verification, and enforcement actions.[187] Partner jurisdictions may require additional criteria for CDM projects to guarantee they meet the WCI's offset project standards.[188] The WCI is currently working on Offset Process Draft Recommendations that will detail more specific requirements for registration, validation, monitoring, quantification, reporting, verification, certification, and issuance of offsets.[189]

In response to the Design Recommendations' call for further review of priority offset protocols, the WCI has begun protocol development to ease regionwide use of three types of offset projects: Agriculture (soil sequestration and manure management); Forestry (afforestation/reforestation, forest management, forest preservation/conservation, forest products); and waste management (landfill gas and wastewater management).[190]

The WCI's offset program does not currently include provisions for CCS technology, but it does flag CCS as a possibility in the future. For example, §8.2 of the Design

174. WCI Design, *supra* note 163, at DD-37, §7.2.5.4; *see also* WCI, Frequently Asked Questions, *supra* note 171.
175. Carolyn Whetzel, *Western Climate Initiative Proposes Mandatory Emissions Reporting Rules*, 40 Env't Rep. (BNA) 1114 (May 15, 2009); *WCI Working With EPA to Resolve Differing GHG Reporting Requirements,* XXI Clean Air Rep. 25:27 (Dec. 9, 2010).
176. *Major Energy Companies Plan Attack on Western Climate Program,* XIX Clean Air Rep. (Inside EPA) 25:34 (Dec. 11, 2008).
177. *See* Washington Dept. of Ecology, Chapter 173-441 WAC—Reporting of Emission of Greenhouse Gases, *available at* http://www.ecy.wa.gov/programs/air/globalwarm_RegHaze/GreenHouseGasreporting_rule.html.
178. WCI Design, *supra* note 163, at 24-25.
179. WCI, Offset System Essential Elements Final Recommendations Paper (July 2010), *available at* http://westernclimateinitiative.org/component/remository/Offsets-Committee-Documents/Offsets-System-Essential-Elements-Final-Recommendations [hereinafter WCI Offset Recommendations].
180. WCI Design, *supra* note 163, at DD-27, §5.3; §8.
181. WCI Offset Recommendations, *supra* note 179, §3.2.3.
182. WCI, Design Recommendations for WCI Regional Cap-and-Trade Program (2008) §9.2, at 10, *available at* http://www.westernclimateinitiative.org/document-archives/wci-design-recommendations [hereinafter WCI Design Recommendations].
183. WCI Design, *supra* note 163, at DD-43, §8.
184. *Id.*
185. WCI Offset Recommendations, *supra* note 179, §3.2.3.1, at 5. Offsets not meeting the WCI criteria will not be accepted for compliance purposes.
186. WCI Design Recommendations, *supra* note 182, §9.3, at 10.
187. *Id.* §9.7, at 11.
188. *Id.* §9.8, at 11.
189. WCI Design, *supra* note 163, at DD-40 §8.
190. WCI, Offset Protocol Review Report (April 2010), *available at* http://www.westernclimateinitiative.org/component/remository/Offsets-Committee-Documents/Offset-Criteria-Draft-Recommendations/.

Recommendations mandates that each Partner jurisdiction agree to dedicate a portion of the jurisdiction's allowance budget to regionwide research, development, demonstrations, and deployment of CCS technology.[191] This provision also "[p]romot[es] emission reductions and sequestration in agriculture, forestry and other uncapped sources."[192] The explanation for the "permanent" requirement for offsets also mentions sequestration of carbon, although it does not differentiate between geological or biological sequestration. In order for sequestration to qualify for offset status, it should achieve the same atmospheric effect as non-sequestration projects, which is based on the international standard developed by the United Nations Framework Convention on Climate Change (currently 100 years).[193] However, the Offset Protocol document does not specifically address or mention CCS or related technology.

While the WCI is progressing in documenting its program design and developing policies to complement its cap-and-trade program, a review of how proposals have developed through the collaborative process of the WCI shows that definitive regional control or specific limitations for Partner jurisdictions have been softened or removed from final documents. The WCI seems to be moving away from policies that could be construed as centralizing control in the WCI. For example, the emphasis on a regionwide cap set forth in the Design Recommendations changed to emphasize only individual jurisdictional caps in the Final Design document. The Design Recommendations set forth guidance for the WCI to apportion allowances based on Partner jurisdiction emissions limits.[194] The Final Design document makes no mention of regional apportionment, and instead emphasizes only regional consultations: "Although developed in a regionally-coordinated manner through these guidelines, each Partner jurisdiction will determine and adopt its own budget. Each Partner jurisdiction will also determine how allowances within its budget will be distributed (e.g., to address competitiveness and leakage issues)."[195] The regional administrative organization described in the Design Recommendations is not mentioned in the Final Design and seems to be replaced by a Program Authority in each Partner jurisdiction, which will administer the program based on recommended standards and discretionary avenues of regional coordination.[196]

For the WCI program to become a reality, member states and provinces must enact the necessary implementation legislation. In the political climate after 2010 midterm elections, there is great uncertainty as to whether the disparate interests of the western states can lead to a uniform regional approach.[197] The governors of California, Oregon, and Washington support the WCI cap-and-trade program, but legislatures in New Mexico, Oregon, Utah, and Washington have sought to delay implementation of the WCI program and require more legislative involvement. Arizona, Montana, and Utah postponed considering legislation in 2009, and Arizona's new governor signed an executive order that barred Arizona's participation in the WCI's cap-and-trade program.[198] California's 2006 global warming law, AB 32, which calls for a reduction of GHG emissions to 1990 levels by 2020 (more stringent than the WCI) is also politically vulnerable. California is being sued by environmentalists, who claim California's regulations are not as stringent as the law requires,[199] while industry proponents managed to put the law on a ballot initiative in the November election that could have essentially killed the bill.[200] While the AB 32 ballot initiative was defeated, another ballot initiative (Proposition 26) will likely be used by opponents to challenge AB 32 in court.[201] As of early 2011, California is the only WCI member state that is moving to implement a cap-and-trade program. The Canadian provinces of British Columbia, Ontario, and Quebec also may approve a cap-and-trade program or a functional equivalent to begin in 2012.[202]

III. State CCS Efforts

A. State Property Law and CCS

In the United States, the right to use underground reservoirs and the associated pore space for storage is considered to belong to the surface owner, unless those rights have been legally transferred to another person or entity.[203] However, those with mineral rights have the right to reasonable use of pore spaces as needed to capture minerals.[204] State law generally governs property issues except on federal lands. State laws vary, and much of the law is based on case law that has developed from conflicts over oil and gas contracts or lease provisions. The generally accepted interpretation

191. WCI Design Recommendations, *supra* note 182, §8.2, at 7.
192. *Id.*
193. WCI Design, *supra* note 163, at DD-42-43, §8.
194. WCI Design Recommendations, *supra* note 182, §§6.2 and 7.
195. WCI, Guidance for Developing WCI Partner Jurisdiction Allowance Budgets, at 2 (July 8, 2010). *See also* §3.
196. *Compare* WCI Design Recommendations, *supra* note 182, §13, *and* WCI Design (final), *supra* note 163, §7.
197. *See, e.g.*, Nora Macaluso, *Midwest Climate Accord Languishes, Leaving States to Take Actions Alone*, 41 Env't Rep. Cur. Dev. (BNA) 2122 (Sept. 24, 2010).
198. Holland & Hart, Update on Western Climate Initiative Legislation (Mar. 17, 2009); William H. Carlile, *State Decides Against Implementing Climate Proposal, Cites Economic Lag*, 41 Env't Rep. Cur. Dev. (BNA) 390 (Feb. 19, 2010).
199. *Activists Charge California Climate Rules May Violate State Law*, XIX Clean Air Rep. (Inside EPA) 17:9 (Aug. 21, 2008).
200. *See* John Hoeffel & Margot Roosevelt, *California Voters Turning Against Prop. 19 and Prop. 23, Poll Shows*, L.A. Times (Oct. 21, 2010), http://www.latimes.com/news/local/la-me-1021-prop-poll-20101021,0,1066812.story (last visited Feb. 20, 2011).
201. *See* Margot Roosevelt, *Lawyers, Lobbyists, Politicians Scramble to Determine Impact of Prop. 26*, L.A. Times (Nov. 14, 2010), *available at* http://www.latimes.com/news/local/la-me-prop26-impact-20101115,0,2819277,full.story (last visited Nov. 22, 2010).
202. *California Sees New Mexico Cap & Trade Rules as Clearing Way for WCI,* XXI Clean Air Rep. (Inside EPA) 15:30 (July 22, 2010); *Inaction by Canadian Provinces Casts More Doubt Over Launch of WCI*, XXII Clean Air Rep. 3:26 (Feb. 3, 2011).
203. The Interstate Oil and Gas Compact Commission, *Storage of Carbon Dioxide in Geologic Structures, A Legal and Regulatory Guide for States and Provinces* 11 (2007) [hereinafter IOGCC].
204. *See* Ian J. Duncan et al., *Pore Space Ownership for CO_2 Sequestration in the U.S.*, 1 Energy Procedia 4427, 4429-30 (2009).

of oil and gas leases is that any property right not explicitly conveyed is retained by the grantor, usually the surface owner.[205] For this reason, the decisions are often based on the language of the documents in dispute. For example in *Mapco v. Carter*,[206] a Texas district court ruled the mineral owner's rights prevailed over the surface owner's rights, because the natural gas was being stored in a cavern formed only by removing the mineral in question—salt—and the lease reserved all minerals to the mineral owner. Almost all other cases have held that the pore space belongs to the surface owner.[207] Most states follow "the American Rule" that after subsurface minerals have been removed, the surface owner owns the depleted space.[208] A minority of states follow "the English Rule," such as Kentucky and Texas, which allows the mineral owner to continue to own the pore space after all minerals have been extracted.[209] This approach creates uncertainty, because it is not easy to determine when the reservoir has been depleted. The age of the case law on this subject, its focus on oil and gas law, and its fact-dependency make the precedent of marginal value, and several authors have recently called the majority/minority interpretation into question.[210] Case law does demonstrate the need for certainty in this field if large-scale CCS development is to occur. It would be best if ownership rights were clarified through legislation to avoid the need for CCS operators to obtain approval (with the associated costs and potential for litigation) from the holders of all potential property interests on a case-by-case basis.

Bills are pending in both the House and the Senate that would designate pore space as belonging to the surface owner for federal lands.[211] Some states have also begun the process of specifying pore space ownership through legislation. In Wyoming, pore spaces were declared to be the property of the surface owner.[212] In Montana, H.B. 498 became law on May 6, 2009. It upholds common-law interpretations of property rights and provides that, unless otherwise discernable from deeds or severance documents, ownership of storage reservoirs will be presumed to attach to surface ownership.[213] However, mineral owners still have the right to drill around or through pore space owned by the surface owner, as long as they meet certain state safety requirements.[214] After completion of the project and 15 years of monitoring, the CCS facility owner may transfer ownership and liability to the state if specific conditions are met.[215] Other states seem to follow the recommendation of the IOGCC and designate the CCS facility owner as the owner of any CO_2 injected for the purpose of sequestration without explicitly designating pore space ownership.[216]

Because of the variation in the details of state CCS regulatory programs, there have been attempts to bring some consistency to the process. In 2007, the IOGCC issued a model program based on existing oil and gas regulatory programs that includes model statutes and regulations to help states develop legal mechanisms encouraging the use of CCS. The IOGCC guidance covers both property law and liability issues.[217] The IOGCC believes it is essential for the storage project to be controlled by the operator of the sequestration project, regardless of who owns the pore space. This necessitates acquisition of the necessary property interests from the landowner, and possibly mineral owners.

As states develop geological sequestration programs, they will also face constitutionally based challenges concerning the extent to which an owner of the surface or subsurface estate can control areas deep below ground. If subsurface pore space is used for sequestration by state governments, will surface or subsurface owners have a cause of action for a physical or regulatory taking under the Fifth Amendment for which compensation would need to be paid? These issues have been covered in a seminal article by Profs. Alexandra Klass and Elizabeth Wilson, and will only be lightly treated in this Article.[218]

Until the advent of air travel, ownership of land extended to the sky and to the center of the earth. But in 1946, the U.S. Supreme Court declared the air to be a public highway.[219] No similar decision has been made concerning sub-

205. *Id*. at 4430; Adam S. Vann, Legislative Attorney, American Law Division of the Congressional Research Service, Carbon Capture and Sequestration Legislation 7, testimony before the Committee on Energy and Natural Resources, Apr. 20, 2010, *available at* http://energy.senate.gov/public/index.cfm?FuseAction=Hearings.Testimony&Hearing_ID=f7492203-de28-8890-5335-601db031dfed&Witness_ID=6b9a9250-ea7c-4e60-9220-8d1b88c7870f (last visited Nov. 22, 2010).
206. 808 S.W.2d 262 (Tex. App.-Beaumont 1991), *rev'd in part,* 817 S.W.2d 686 (Tex. 1991).
207. *But cf.* Central Ky. Natural Gas Co. v. Smallwood, 252 S.W.2d 866, 868 (Ky. 1952). Two recent analyses of cases holding in favor of mineral owners distinguish these holdings by the specific facts of the case, arguing that unless lease language or court interpretations of surrounding circumstances provide a reason to give ownership rights to a mineral owner, case law in the United States upholds pore space as property belonging to the surface owner. *See generally* Duncan et al., *supra* note 204; *see also* Vann, *supra* note 205 at 5-6. These cases are also discussed in a paper prepared by David Cooney found in the IOGGC report, *supra* note 203, at 14-22.
208. IOGCC, *supra* note 203, at 116.
209. Elizabeth J. Wilson & Mark A. de Figueiredo, *Geologic Carbon Dioxide Sequestration: An Analysis of Subsurface Property Law,* 36 ELR 10114, 10117 (Feb. 2006). Williams & Meyers present the counter-argument that mineral owners should have property rights to pore space, at least in relation to storage of natural gas. *See* Williams & Meyers, 1-2 Oil & Gas Law §222 (Conclusions) (Lexis 2010).
210. *See generally* Duncan et al., *supra* note 204.
211. A Bill to Amend the Energy Policy Act of 2005 to Clarify Policies Regarding Ownership of Pore Space, S. 1856, H.R. 6077, 111th Cong. (2009-10).
212. Wyo. Stat. Ann. §34-1-152 (H.B. 0089) (2008).
213. Montana S.B. 0498 §1(3) (2009).
214. Montana S.B. 0498 §1(1)(b) (2009). Most states have a similar provision, allowing mineral rights owners access around or through carbon sequestration reservoirs subject to specific approvals and safety requirements.
215. Montana S.B. 0498 §§6, 7 (2009).
216. *See, e.g.*, 27A Okla. Stat. Ann. §3-5-105 (West 2010); Tex. Nat. Res. Code Ann. T.3, subpt. D, ch. 120 (Vernon 2010). In Oklahoma, mineral rights are considered to be incorporeal, meaning they entail the right to try to capture the minerals, but the minerals themselves do not belong to the party with mineral rights until they are captured. Texas views mineral rights as property rights. However, ownership of the pore space does not seem to be spelled out in either state's legislation, and as discussed above, common-law interpretations leave some confusion about ownership rights.
217. IOGCC, *supra* note 203, at 23. Another model rule is found in Victor B. Flatt, *Paving the Legal Path for Carbon Sequestration From Coal,* 19 Duke Envtl. L. & Pol'y F. 211, 242 (2009).
218. Alexandra B. Klass & Elizabeth J. Wilson, *Climate Change, Carbon Sequestration, and Property Rights*, 2010 U. Ill. L. Rev. 363 (2010) [hereinafter Klass & Wilson, *Property Rights*].
219. United States v. Causby, 328 U.S. 256, 260-61 (1946).

surface rights, which have been subject to an extensive body of property laws designed to protect owners of land.[220] In 1982, the Supreme Court made it clear that the government's physical occupation of land is a taking for which compensation is required.[221] However, the Court has never ruled whether land far beneath the surface belongs to those holding property interests in the surface land, although a significant body of relevant state law has developed regarding oil and gas development, underground waste injection, and natural gas storage.[222]

Natural gas storage was the subject of congressional action in the Natural Gas Act that implicitly recognizes a property interest in the use of land for subsurface storage of natural gas, and this property right is subject to the power of eminent domain.[223] The law of damages for adverse impacts on land from oil and gas secondary recovery is usually based on state statutes governing the petroleum industry, but the absolute ownership doctrine (defining land ownership as extending to the periphery of the universe) is usually rejected.[224] Waste-injection cases, in which surface owners seek recovery for damages to their property caused by deep well-injection, usually require plaintiffs to prove harm to actual use of the subsurface.[225] This led Professors Klass and Wilson to conclude that the law is not clear, and courts that face carbon sequestration takings issues have options ranging from recognizing property rights in pore space only when actual harm to the pore space itself or ongoing economic uses occurs, to recognizing a property interest in subsurface pore space, regardless of use or reasonably foreseeable use. However, even if an absolute right to the pore space is recognized, the amount of compensation provided in such cases will determine the importance of an absolute right.[226] Prof. John Sprankling argues that private property rights to land should not extend more than 1,000 feet down, and pore space below that depth should be publicly owned.[227] Professor Sprankling's suggested cutoff depth is probably unrealistic, given the depth at which oil and gas and other mineral industries now work, sometimes far in excess of 1,000 feet. A better approach, according to Professors Klass and Wilson, is to pass legislation authorizing deep subsurface carbon sequestration that terminates private subsurface property interests except for uses already being made or uses that are based on reasonable investment-backed expectations.[228]

A per se regulatory taking occurs if a landowner is deprived of all reasonable, beneficial use, even in the absence of any physical taking. However, based on *Lucas v. South Carolina Coastal Council*,[229] even if all economic use of the property is denied by a regulation, it may not be a per se regulatory taking if the restriction is based on the law of nuisance. This holding makes it even more difficult to prove a regulatory taking occurred.[230] If a property has some economic value remaining, the balancing test found in *Penn Cent. Transp. Co. v, New York City*[231] will be used to determine whether a regulatory taking has occurred. The application of the balancing tests in a carbon sequestration case will be affected by whether courts consider the pore space to be an independent property right that can be considered separately from the use of the entire property. Even if a taking is established, a property owner is required to show its losses in order to be eligible for federal economic assistance.[232] For most properties, this mandate will limit potential claimants.

Additional problems are created if the subsurface estate is held by more than one entity. For example, ownership issues have arisen in coal-bed methane (CBM) controversies, where the issue is whether the coal owner or the natural gas owner has the right to extract CBM. The American Rule is that CBM belongs to the natural gas owner, not the coal owner.[233] If the title to the pore space is held by the surface owner, and coal underlying a tract of land has been severed from the other mineral interests, what are the rights of those owning part of the subsurface estate? One effort to deal with split estate issues is found in the Wyoming Surface Owner Accommodation Act that provides protection for surface owners from surface activities of the subsurface owners.[234] A similar approach may be needed to protect subsurface interests if the surface owner allows geological sequestration to occur.

B. State CCS Permits

In December 2010, EPA finalized federal rules for underground injection of CO_2 for purposes of geological storage (GS) (UIC Rules).[235] With the release of the EPA's final rule covering CO_2 injection underground for storage purposes, there is both more surety for CCS projects and less discretion for state control of CCS. Operators of all CCS projects will now need an operating permit from either the state where the project is located or from EPA. The permitting authority will require detailed engineering and geological data that demonstrate the suitability of the site for long-term carbon sequestration. The size of the project area that will be monitored and reviewed will also be defined by the permitting authority. The UIC Rules are promul-

220. Klass & Wilson, *Property Rights*, *supra* note 218, at 389.
221. Loretto v. Teleprompter Manhattan CATV Corp., 458 U.S. 419 (1982).
222. *See* Klass & Wilson, *Property Rights*, *supra* note 218, at 391; Duncan, *supra* note 204, at 4428-31.
223. 15 U.S.C. §717f(h) (Lexis 2010); Klass & Wilson, *Property Rights*, *supra* note 218, at 401.
224. Klass & Wilson, *Property Rights*, *supra* note 218, at 397.
225. *Id.* at 398.
226. *Id.* at 404.
227. John G. Sprankling, *Owning the Center of the Earth,* 55 UCLA L. Rev. 979, 982 (2008).
228. Klass & Wilson, *Property Rights*, *supra* note 218, at 408.
229. 505 U.S. 1003, 1028-29, 22 ELR 21104 (1992).
230. Klass & Wilson, *Property Rights*, *supra* note 218, at 415.
231. 438 U.S. 104, 8 ELR 20508 (1978).
232. Klass & Wilson, *Property Rights*, *supra* note 218, at 418.
233. Allan Ingelson & Lincoln Mitchell, *CBM Legal Issues—The Western U.S.A. and Canada*, 47 Rocky Mtn. Min. L. Found. J. 19, 31 (2010).
234. Wyo. Stat. Ann. §§30-5-401 to 30-5-410.
235. Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells, 75 Fed. Reg. 77230 (Dec. 10, 2010) (to be codified at 40 C.F.R. pts. 124, 144, 145, 146, and 147) [hereinafter UIC Rules].

gated under the Safe Drinking Water Act (SDWA)[236] and establish a new category of injection wells, Class VI, that covers underground injection for the purpose of geologic storage of CO_2. The UIC Rules require 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 inject into suitable formations. Class VI well owners or operators must also identify additional confining zones, if required by the Director, to increase protection for underground sources of drinking water. Owners or operators must submit, with their permit applications, a series of comprehensive site-specific plans: An area of review (AoR) and corrective action plan; a monitoring and testing plan; an injection well-plugging plan; a post-injection site care (PISC) and site-closure plan; and an emergency and remedial response plan. The requirement for a comprehensive series of site-specific plans is new to the UIC program.[237]

Under SDWA §1421(b), the UIC Rules mandate that EPA develop minimum federal requirements that a state must meet to achieve UIC primary enforcement responsibility, or primacy, to ensure protection of underground sources of drinking water (USDW). If states want to implement the UIC program, they must apply to EPA for primacy approval. In the primacy application, states must 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. EPA will directly implement the UIC program for states that do not apply for primacy and for states that only have primacy for part of the UIC program.[238] EPA will allow states to achieve independent primacy for Class VI wells, under §145.1(i) of the final rule, and will accept applications from states for independent primacy under §1422 of the SDWA for managing UIC storage projects under Class VI. EPA's willingness to accept independent primacy applications for Class VI wells applies only to Class VI well primacy, and does not apply to any other well class under SDWA §1422 (i.e., I, III, IV, and V). States will have 270 days following EPA's final promulgation of the geologic storage rule on September 6, 2011, to submit a complete primacy application that meets the requirements of §§145.22 or 145.32.

Section 145.23(f)(1) requires states with primacy to include a schedule for issuing Class VI permits for wells within the state that require the permits within two years after receiving program approval from EPA, and §145.23(f)(2) requires states to include their permitting priorities, as well as the number of permits to be issued during the first two years of program operation. State or EPA directors must also submit a plan to notify existing owners/operators of Class I wells that have become storage sites or Class V experimental wells that will now be used for storage that they must apply for a Class VI permit to either the state or EPA permitting authority within one year of December 10, 2011.

Section 146.82(a)(2) requires the owner or operator of a CCS operation to identify all state, tribal, and territorial boundaries within the AoR. Based on the information provided to the state or EPA Director during the initiation of the permit application, the Director, pursuant to requirements at §146.82(b), must provide written notification to all states, tribes, and territories in the AoR to inform them of the permit application and to afford them an opportunity to be involved in any relevant activities (e.g., development of the emergency and remedial response plan (§146.94)). Owners or operators must periodically reevaluate the AoR to incorporate monitoring and operational data and to verify that the CO_2 is moving as predicted within the subsurface. 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." EPA is developing guidance on AoR and corrective action to support AoR delineation (i.e., including regions of the CO_2 plume and pressure front). Under the proposed approach, AoR reevaluation would occur at a minimum of every 10 years during CO_2 injection, or when monitoring data and modeling predictions differ significantly. Periodic AoR reevaluation is an integral component of this approach. 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.

The UIC Rules, at §146.91(e), also require that all 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, as well as those in states where EPA implements the Class VI program, pursuant to §147.1. All Directors will have access to the data through the EPA electronic data system.

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 §146.91(e), information to the Director to support Class VI permit applications (this information is enumerated at §146.82). This information includes: site-characterization information on the stratigraphy, geo-

236. 42 U.S.C. §§300f to 300j-26, ELR Stat. SDWA §§1401-1465.
237. UIC Rules, *supra* note 235, at 77293.
238. *Id.* at 77241.

logic 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.

Class VI well owners or operators must retain data collected to support permit applications and data on the CO_2 stream until 10 years after site closure. Owners or operators must retain monitoring data collected under the testing and monitoring requirements at §146.90(b-i) for 10 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 (§146.91(f)(5)). Well-plugging reports, PISC data, and site-closure reports must be kept for 10 years after site closure (§§146.92(d), 146.93(f), and 146.93(h))

Section 146.92 requires owners or operators of Class VI wells to plug injection and monitoring wells in a manner that protects USDWs. The final rule, at §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 (§146.92(b)). The approved injection well-plugging plan will be incorporated into the Class VI permit. The Agency is developing guidance that describes the contents of the project plans required in the GS rule, including the injection well-plugging plan.

Upon cessation of injection, the UIC Rules require that 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 (§146.93(a)(3)). 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 50-year PISC time frame. However, the final rule affords flexibility regarding the duration of the PISC time frame by: (1) allowing the Director discretion to shorten or lengthen the PISC time frame during the PISC period based on site-specific data, pursuant to requirements at §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 time frame is appropriate, if it ensures nonendangerment of USDWs pursuant to requirements at §146.93(c). Section 146.93(c) provides the Director discretion to approve a demonstration during the permitting process (per requirements at §146.82(a)(18)) that an alternative PISC time frame, other than the 50-year default, is appropriate.

Following a determination under §146.93 that the site no longer poses a risk of endangerment to USDWs, the Director would approve site closure, and the owner or operator would be required to properly close site operations. These site-closure requirements are 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 (§146.93(d) through (h)).

The rule also finalizes regulations at §146.85 that require owners or operators to demonstrate and maintain financial responsibility, as approved by the Director, for performing corrective action on wells in the AoR, injection well-plugging, PISC and site closure, and emergency and remedial response. 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 §1423 of the 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, or under §1423 of the SDWA for violating §144.12, such as where the owner or operator provided erroneous data to support approval of site closure. Additionally, an owner or operator may always be subject to an order the EPA Administrator deems necessary to protect the health of persons under §1431 of the SDWA after site closure, if there is fluid migration that causes or threatens imminent and substantial endangerment to a USDW.

The finalization of these EPA regulations will impact the state CCS controls discussed in this Article. EPA is currently tracking regulatory efforts in 18 states: Colorado, Illinois, Kansas, Kentucky, Louisiana, Michigan, Mississippi, Montana, New Mexico, New York, North Dakota, Oklahoma, Pennsylvania, Texas, Utah, Washington, West Virginia, and Wyoming. EPA is considering this information as it develops guidance on the primacy application and approval process for Class VI wells. States have taken considerable action to regulate, promote, and secure CCS projects throughout the United States.

West Virginia enacted H.B. 2860 on May 4, 2009, to regulate CCS. On the same day, the West Virginia Department of Environmental Protection issued an underground injection permit to allow the Appalachian Power Company to inject up to 165,000 metric tons of CO_2 over a four- to five-year period from its Mountaineer Plant. The facilities that are permitted must comply with the Clean Water Act (CAA)[239] and meet West Virginia's new requirements for site monitoring, notice if sequestered CO_2 is released, guidelines for terminating a CCS project, and post-closure. Civil penalties up to $25,000 per day are established for violations of these state requirements. This project will only

239. 33 U.S.C. §§1251-1387, ELR Stat. FWPCA §§101-607.

sequester a small portion of the plant's CO_2 emissions, but it is the first CCS project at an existing facility.[240]

Kansas enacted legislation in March 2007 that directs the Kansas Corporation Commission to develop CCS rules.[241] The Kansas rules require well construction standards and a storage permit, but no underground injection permit is required. Kansas law also creates a fund to pay for the costs of regulation, remediation, and monitoring of CCS activities.[242]

As more states develop regulatory programs, various issues need to be resolved. What concentration of CO_2 will trigger the applicability of CCS legislation? How much contamination should be allowed in the injected waste stream? How are CO_2 concentrations to be monitored and enforced? How is the appropriateness of the site to be demonstrated? What control over the use of models for risk assessment, site integrity, plume movement, etc., will be given to the permitting authority? What baseline data will be required, and who will be responsible for developing it? Will health impacts on drinking water be regulated, and will other health impacts be regulated? Are ecosystem impacts, including impacts on wildlife, to be covered? How long must the CO_2 be sequestered? How are the site selection and design of the facility going to achieve that goal? What remedies are available to the state if the CCS facility leaks outside the reservoir or into the atmosphere? How is the reservoir defined so as to determine when CO_2 is not being confined? How is the geologic integrity of the facility to be monitored, and what are the remedies if there is a failure of the containment, including triggering earthquakes, subsidence, or other breaches of the physical integrity of the facility? What other monitoring will be required? What authority will the state have to determine the need for mitigation or remediation of the site, and what authority will it have over implementation of such measures? How long after the injection ends will the operator remain liable? What must the operator show in order to have the state assume long-term responsibility for the site? Under what circumstances can the liability of the operator be revisited? As state permit programs proliferate, an important issue will be whether federal laws will be enacted that preempt or restrict state permit requirements.[243]

C. State Monitoring, Closure, and Post-Closure Requirements

After injection activities cease, a well should be plugged in a manner required by state or federal regulations. The IOGCC has recommended a two-stage process with a Closure Period and a Post-Closure Period. The Closure Period begins when the injection well is plugged and continues for a specified time. The IOGCC recommends 10 years.[244] During the Closure Period, the operator would be responsible for site monitoring and for maintaining a facility bond to assure that resources are available to meet closure obligations. At the end of this defined period, the operator must demonstrate that the well is not releasing CO_2 outside the boundaries of the reservoir or into the atmosphere and that the operation is in compliance with applicable federal and state law. If the state agrees, it would assume the long-term stewardship obligation, and the operator's bond would be released. It would be useful to create an industry-funded trust fund that is administered by the state to assure that money is available to cover the costs of post-closure state management, including monitoring, verification, and any remediation actions that may be required in the future. The money for the trust fund could be generated from a per-ton charge on the CO_2 at the time it is injected.[245]

D. Renewable Portfolio Requirements

The failure of the federal government to develop a sustainable electrical energy policy has led to state efforts that encourage and discourage the use of fossil fuel to generate electricity. States have created renewable portfolio standards (RPSs), trust funds to encourage renewable energy, and net metering requirements to promote decentralized, distributed energy.[246] On the other hand, some states allow standby service charges on dispersed generators, charge exit fees for customers that depart from centralized electric power providers, and resist transmission infrastructure upgrades that protect existing fossil-fuel generators from competition from new technologies or out-of-state electricity providers.[247]

Perhaps the most important of these state actions is the spread of state RPSs that require electric utilities to meet a specified percentage of their electricity sales using renewable resources. In 2010, 36 states and the District of Columbia had RPSs.[248] However, there is little consistency among the state RPS statutes. Iowa, in 1991, was the first state to enact an RPS. Iowa, as well as most states that subsequently enacted RPSs, specified a percentage of electricity that had to be generated from renewable sources. The required standards range from 0.2 to 33%.[249] New York, for example, requires 25% of the state's power to be generated from renewable sources by 2013; California requires at least 20% by 2017[250]; the District of Columbia requires

240. Bebe Raupe. *Officials Issue State's First Permit to Allow Carbon Dioxide Sequestration*, 40 Env't Rep. (BNA) 1091 (May 8, 2009).
241. Kan. Stat. Ann. §§55-1636 et seq. (West 2010); H.B. 2419 (Mar. 2007).
242. The Kansas and Washington approaches are discussed in Klass & Wilson, *supra* note 218.
243. For example, the Energy Policy Act of 2005 §311, 15 U.S.C. §717b(e)(1), preempted local and state control over the siting of liquefied natural gas facilities. The law was upheld in *AES Sparrows Point LNG, L.L.C. v. Smith*, 470 F. Supp. 2d 586, 589, 37 ELR 20161 (D. Md. 2007). This could be a model for CCS legislation.
244. IOGCC, *supra* note 203, at 11.
245. *Id.*
246. Steven Ferry, *Power Future,* 15 Duke Envtl L. & Pol'y F. 261, 284 (2005).
247. *Id.* at 284, 288.
248. Lincoln L. Davies, *Power Forward: The Argument for a National RPS,* 42 Conn. L. Rev. 1339 (2010).
249. For a comprehensive summary of state actions, see http://www.dsireusa.org/ (last visited Nov. 4, 2010); *see also* Ari Natter, *Coalition Urges "Rapid Enactment" of Bill to Establish Renewable Electricity Standard,* 40 Env't Rep. (BNA) 688 (Mar. 3, 2009).
250. Paul A. O'Hop, *Growing Green Power,* Legal Times, May 16, 2005, at 39.

20% by 2020[251]; and Colorado requires 30% by 2020.[252] The renewable percentage and time for compliance of the mandates do not accurately describe the efforts of the state legislatures, however, because the requirements can range from strict mandates to voluntary.[253] Moreover, credit multipliers are used by many states to provide additional subsidies to certain types of renewable resources or to benefit renewable power generated within the state.[254]

Some states require a minimum percentage of the power sold in the state to come from renewable energy, which is known as a "bundled" approach. In 2010, only Arizona, California, Illinois, and Iowa were considered to be bundled states. In California, utilities must submit a procurement plan for renewable purchases to the California Public Utilities Commission (PUC). After PUC approval, the utilities must contract for the purchase of renewable electricity and have the PUC approve the contracts.[255] Other states with RPSs use an "unbundled" approach that allows utilities to purchase renewable energy credits (RECs) from electric power generators located anywhere in the country to meet RPS mandates. RECs are tradable commodities, with each REC typically representing one megawatt hour of electricity generated from a renewable source.[256] But the time allowed for the RECs to be used range from one year to unlimited.[257] The variability of the state RPS programs is a constraint on the development of a viable trading system.[258]

States, such as California, with renewable portfolio requirements are also discovering the construction of facilities needed to meet RPS will not be met by the imposed deadlines.[259] Moreover, RPS may not produce carbon reductions beyond those that could be achieved with a cap-and-trade system. It has been argued that cap and trade will achieve the same objective as RPS at a lower cost and will preserve the freedom of the regulated entities to decide how to best comply.[260] But cap and trade faces its own implementation hurdles. Federal efforts at RPS include President Obama's call for 25% of the nation's electric power to be generated from renewables by 2025. The Waxman-Markey Bill includes a federal renewable portfolio and electricity savings standard starting at 6% in 2012 and increasing to 20% in 2020. The Waxman-Markey Bill limits the use of energy-efficiency measures to meet the mandate of 40% of the combined renewable electricity and electricity savings requirement.[261] However, as discussed above, federal efforts to enact either cap and trade or RPS legislation in 2010 failed.

Because many states have or are in the process of enacting renewable portfolio requirements, it is important to specify if, and how, CCS will affect such requirements. Will the percentage of renewable energy that is required be based on the electric power generated, or will it be based on the power generated minus production whose emissions are sequestered? How will future leakage of sequestered CO_2 be treated in regards to renewable requirements? Most of the laws are silent as to the effect that CCS will have on RPS requirements. One approach is to consider CCS the equivalent of renewable energy and to issue RECs for CO_2 sequestered that will help meet an RPS requirement. This would mean that CCS would compete with other renewable resources for an electric power generator's capital investment dollars. Another possibility is that CCS would lower the total electric power generated against which the RPS is calculated. This would allow CCS investments to lower RPS requirements. A third possible approach would be to treat CCS as having no effect on RPS requirements. The second approach would appear to be the most desirable approach.

E. Tort Liability

A barrier to the implementation of CCS is the potential liability for mishaps. Injected CO_2 could be released to the atmosphere through undetected faults or abandoned well bores. Large releases that create CO_2 concentrations above 30% could cause death from asphyxiation; lower concentrations would have adverse effects on the health of humans, animals, and plants. The pressure created by injecting large quantities of CO_2 below ground results in CO_2 moving upwards and spreading laterally, which could contaminate potable groundwater, contaminate hydrocarbon resources, create ground heave, or possibly trigger seismic events.[262] Such issues should be addressed in federal statutes authorizing a CCS program. The U.S. Congress could impose or limit liability. For example, the Carbon Storage Stewardship Trust Fund Act of 2009 (S. 1502) that was introduced July 22, 2009, would require operators to have private liability insurance. DOE would be authorized to collect fees from operators to cover possible future liability after the facility was closed.[263]

The Price Anderson Act provides one example of an established liability regime for energy production. This liability regimen for the nuclear energy program provides a strict liability compensation system with an imposed public/private insurance program.[264] A similar approach was

251. Mary Cheh, *Greening the Capital City With a Sustainable Energy Utility,* 40 Trends 10 (ABA Jan./Feb. 2009).
252. *Colorado Gas Bill Touted as Model for States to Meet EPA Air Rules,* XXVII Envtl. Pol'y Alert (Inside EPA) 7:38 (Apr. 7, 2010).
253. *Compare* Haw. Rev. Stat. Ann. §269-92(a)(4) (West 2010), *with* Utah Code Ann. §§54-17-602(1)(a) & 54-7-12(c)(2) (West 2010).
254. *See* Davies, *supra* note 248, at 1399 (app. B) & 1401 (app. D).
255. Tom Mounteer, *To Bundle or Not Bundle,* 40 ELR 10119 (Feb. 2010).
256. *Id.*
257. Davies, *supra* note 248, at 1400 (app. C).
258. *See generally* Davies, *supra* note 248.
259. Carolyn Whetzel, *State's Utilities Face Variety of Hurdles in Drive to Meet Renewable Energy Standard*, 39 Env't Rep. (BNA) 1610 (Aug. 8, 2008).
260. Neal J. Cabral, *The Role of Renewable Portfolio Standards in the Context of a National Carbon Cap-and-Trade Program*, 8 Sustainable Dev. L. & Pol'y 13 (Fall 2007).
261. Congressional Budget Office Cost Estimate, H.R. 2454, American Clean Energy and Security Act of 2009, 8.
262. Klass & Wilson, *Liability*, *supra* note 45, at 129.
263. *See* Dean Scott, *Senators Offer Bill Addressing Liability Issues Raised by Long-Term Carbon Dioxide Storage,* 40 Env't Rep. (BNA) 1822 (July 31, 2009).
264. 42 U.S.C. §2210 (Lexis 2010).

taken in the Trans-Alaska Pipeline Systems Act.[265] There is also a comprehensive financial liability mechanism for dealing with oil spills in the Oil Pollution Act.[266] In the absence of a federal compensation program, traditional tort- and property-based legal remedies would apply. In such cases, it is highly unlikely that a federal common law would be recognized; the state law where the injury occurred would be the applicable law.[267] However, if a comprehensive federal CCS program is created, the defendant in a state tort-based action may or may not be protected if it is in compliance with federal requirements, depending on whether federal law is interpreted as fully preempting state law.[268] Federal law is likely to play an important role in determining the appropriate standard of care or what is reasonable conduct in a state tort action. It has been suggested that for the first dozen CCS projects the government should assume all tort liability in order to spur the development of carbon sequestration. But such an action may have an adverse impact on the selection of safe sites and could encourage risky behavior on the part of operators.[269]

A significant case that deals with federal preemption is *Roberts v. Florida Power & Light Company*.[270] In this 1998 case, the U.S. Court of Appeals for the Eleventh Circuit held that the Price-Anderson Act set the standard of care in an action based on negligence and strict liability for radiation injuries to a worker at a nuclear power facility. This was a "public liability action" within the meaning of the Price-Anderson Act.[271] The issue of concern to the Eleventh Circuit was whether Price-Anderson and federal radiation regulations or state tort standards should be used to determine tort liability. The plaintiff made no assertion that the defendant's emissions exceeded the maximum dose allowed by federal law. The Supreme Court had previously ruled that the Price-Anderson Act did not preempt a state award of punitive damages.[272] But since that ruling, Congress barred punitive awards in 1988 amendments to Price-Anderson where the federal government would be liable for them under an indemnification agreement.[273] Price-Anderson says the substantive law in a public liability action shall be derived from state law, unless the law of the state in which the nuclear incident occurred is inconsistent with the provisions of §2210. The Eleventh Circuit agreed with the U.S. Court of Appeals for the Third Circuit, the U.S. Court of Appeals for the Sixth Circuit, and the U.S. Court of Appeals for the Seventh Circuit that federal nuclear regulations establish the exclusive standard of care owed by operators of nuclear power plants to their workers.[274] As succinctly stated by the Seventh Circuit, "state regulation of nuclear safety, through either legislation or negligence actions, is preempted by federal law."[275] Thus, in the case of nuclear power plants, there has been general agreement among the circuits that federal regulations form the sole duty of care owed by operators of nuclear power plants toward their employees.[276]

The U.S. Court of Appeals for the Tenth Circuit, however, departed from this clear preemption stance in *Cook v. Rockwell International Corporation*,[277] a recent decision involving trespass and nuisance claims against a nuclear facility in Colorado. Instead of looking to federal regulations to provide "the sole measure of the defendants' duty,"[278] as five other circuit courts have done,[279] the Tenth Circuit held that the 1988 amendments to the Price-Anderson Act "expressly maintained the applicability of state tort law in PAA actions."[280] Based on a threshold requirement that the plaintiff prove that a "nuclear incident" had occurred according to the Act's standards, the Tenth Circuit disputed other circuit conclusions that "state tort standards of care, which may have some indirect effect on nuclear safety, are preempted by federal law."[281] Without the proof of a nuclear incident, a plaintiff might still be able to get relief through state tort law. And the determination of whether such laws were preempted by federal nuclear regulations or set a standard of care in conflict with federal standards should be done on a case-by-case basis.[282] Such case-by-case uncertainty can be a serious barrier for development of new and potentially dangerous technologies, such as nuclear power and CCS.

While there is no current decision to reconcile these cases,[283] the process of determining whether federal law preempts state law is based on important considerations that would be relevant for carbon sequestration legislation.

265. Pub. L. No. 93-153 (Nov. 16, 1973), codified at 43 U.S.C. §1653 (Lexis 2010).
266. 33 U.S.C. §§2701-2761, ELR Stat. OPA §§1001-7001.
267. Int'l Paper Co. v. Ouellette, 602 F. Supp. 264, 269, 15 ELR 20377 (D. Vt. 1985), *aff'd*, 776 F.2d 55, 16 ELR 20012 (2d Cir. 1985), *aff'd*, 479 U.S. 481, 17 ELR 20327 (1987).
268. Milwaukee v. Illinois, 451 U.S. 304, 11 ELR 20406 (1981); Middlesex County Sewage Auth. v. Nat'l Sea Clammers Ass'n, 453 U.S. 1, 11 ELR 20684 (1981); Nat'l Audubon Soc'y v. Los Angles Dept. of Water, 869 F.2d 1196, 19 20198 (9th Cir. 1988).
269. Klass & Wilson, *Liability*, *supra* note 45, at 110.
270. 146 F.3d 1305 (11th Cir. 1998).
271. *See* 42 U.S.C. §2014 (West 2010).
272. Silkwood v. Kerr-McGee Corp., 464 U.S. 238, 14 ELR 20077 (1984).
273. *See* 42 U.S.C. §2210(s) (West 2010).
274. *See, e.g.*, In re TMI Litigation Cases Consolidated, 940 F.2d 832, 858-66 (3d Cir. 1991).
275. O'Connor v. Commonwealth Edison Co., 13 F.3d 1090, 1105, 24 ELR 20689 (7th Cir. 1994).
276. *See* Roberts v. Florida Power & Light Co., 146 F.3d 1305, 1308 (11th Cir. 1998).
277. Cook v. Rockwell Int'l Corp., 618 F.3d 1127, 1143, 40 ELR 20241 (10th Cir. 2010).
278. *Roberts*, 146 F.3d at 1308 (quoting O'Connor v. Commonwealth Edison Co., 13 F.3d 1090, 1105, 24 ELR 20689 (7th Cir. 1994)).
279. *See id.*; *O'Connor*, 13 F.3d at 1105; Nieman v. NLO, Inc., 108 F.3d 1546 (6th Cir. 1997); In re TMI Litigation II, 940 F.2d 832; *see also* In re Hanford Nuclear Reservation Litig., 534 F.3d 986, 1003 (9th Cir. 2008) (cited by the Tenth Circuit as another case holding in favor of preemption).
280. *Cook*, 618 F.3d at 1144.
281. *Id.* at 1143.
282. *Id.* at 1144. The court cited defendants' failure to plead "field preemption" as opposed to "conflict preemption" as one basis for its departure from five other circuit court decisions in favor of preemption. *Id.* at 1144, n.19. It also distinguished between a Supreme Court ruling that only the federal government can directly regulate nuclear safety and analysis of preemption of state tort standards, which it claimed was lacking. *Id.* at 1143.
283. It might be possible to reconcile them by looking at the Tenth Circuit case as an outlier because the defendant failed to argue field preemption. However, this analysis is undercut by the Tenth Circuit analysis that the Supreme Court has not yet decided the preemption issue and its directions for case-by-case analysis of whether state law should be preempted.

First, "there is a strong presumption against preemption that may only be overcome by 'clear and manifest' congressional intent to oust state law."[284] Second, this presumption is stronger when preemption would displace the traditional power of the state to protect the health and safety of its citizens.[285] Third, if preemption leaves an injured person without a state or federal remedy, "a court may ascribe preemptive intent to Congress only in the most compelling circumstances."[286] Even if state law is not expressly preempted by Congress, it may be impliedly preempted if Congress occupies the entire field or the state law directly conflicts with federal law and stands as an obstacle to the federal legislative objectives.[287] However, as seen from the *Cook* case, conflict preemption may still leave room for state tort laws to apply. In the absence of express federal preemption, the courts would be unlikely to find there was implied federal preemption, because federal CCS laws occupy the field to the exclusion of state tort or property law or because the state-law conflicts with federal law.[288]

On December 7, 2009, the EPA Administrator made an endangerment finding that six GHGs are air pollutants that may be reasonably anticipated to endanger public health and welfare. EPA did not issue a finding that the endangerment finding cannot be the basis for tort actions. Instead, it responded as follows to concerns about increased litigation:

> [T]he Administrator focuses her endangerment analysis on the science of GHGs and climate change, and not on the potential ramifications for civil tort litigation (corporate- or environmental justice-related) of regulations that may follow positive endangerment and cause or contribute findings.
>
> This [endangerment finding] action is not the appropriate forum for opining on civil tort litigation. The issues before EPA concern the contribution of emissions from new motor vehicles and the impacts of the air pollution on the public health or welfare.[289]

Because EPA has not yet issued a finding that its endangerment determination cannot be the basis for tort actions, it can reasonably be expected that many new tort cases will be filed.

A potential plaintiff in a tort action must plead a cause or causes of action that the legal system will recognize and provide a remedy if the plaintiff prevails. Almost any tort- or property-based cause of action could potentially be the basis for a lawsuit brought to recover for personal injury or property damage caused by CCS. However, it can reasonably be predicted that nearly all actions will be based on private nuisance, trespass, public nuisance, negligence, or strict liability. Because plaintiffs are allowed to plead alternative causes of action, cases are likely to be brought that are based on multiple legal theories. Assuming the absence of federal preemption over state tort-based action, tort law offers a much greater range of remedies than is presently available under federal environmental laws. State tort law can provide injunctive relief and other equitable remedies. It provides compensatory money damages for personal injury and property damage and may allow for the recovery of punitive damages. The methyl tertiary butyl ether (MTBE) cases show that contamination of groundwater can lead to damages in the hundreds of millions of dollars.[290]

A private nuisance has its roots in property law. It is an indirect (or non-trespassory) invasion on another's interest in the private use and enjoyment of land.[291] It may involve interference with the physical condition of land, such as polluting groundwater, or it may disturb the occupants of the land, which may occur if air pollutants impact the property.[292] It includes a threat of future injury, such as may occur when explosives or toxic material are stored on the land.[293] The invasion usually must be a substantial invasion of the property that is unreasonable, based on the values within the community. Determining whether conduct is an unreasonable interference requires a balancing of the interests of the parties.[294] For potential defendants, a nuisance cause of action is always a risk, because an activity may be ruled a nuisance by a court, even if the activity is lawful and properly operated.[295]

Trespass is a direct interference with the right to exclusive possession of land.[296] Until the 1960s, trespass was not a cause of action that could provide relief for most environmental-based interferences with land, because the release of intangibles, such as air pollutants, light, energy, etc. onto another's land, was not considered a direct interference with possession of land.[297] This has changed, and the most important cases recognizing trespass as a valid cause of action to address air pollution are a series of cases in Oregon and Washington in the 1960s that involved fluoride emissions.[298] A trespass can be committed above

284. Wisconsin Public Intervenor v. Mortier, 501 U.S. 597, 605, 611, 21 ELR 21127 (1991).
285. *See* Rice v. Santa Fe Elevator Corp., 331 U.S. 218, 230 (1947).
286. *See* Silkwood v. Kerr-McGee Corp., 464 U.S. 238, 251, 14 ELR 20077 (1984).
287. *See* Florida Lime & Avocado Growers, Inc v. Paul, 373 U.S. 132, 142-43 (1993); Hines v. Davidowitz, 312 U.S. 52, 67 (1941).
288. *See generally* Capollone v. Liggett Group, Inc., 112 S. Ct. 2608 (1992); California Coastal Comm'n v. Granite Rock Co., 107 S. Ct. 1419, 17 ELR 20563 (1987).
289. U.S. EPA. Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act: EPA's Response to Public Comments (Vol. 11: Miscellaneous Legal, Procedural, and Other Comments), §111.12.2, *available at* http://www.epa.gov/climatechange/endangerment/comments/volume11.html#12-2.
290. *See* Arnold W. Reitze Jr., *Biofuels—Snake Oil for the Twenty-First Century*, 87 Or. L. Rev. 1183 (2009).
291. Restatement of Torts, §822.
292. *See generally* Julian Conrad Juergensmeyer, *Control of Air Pollution Through the Assertion of Private Rights,* 1967 Duke L.J. 1126 (1967); Harold W. Kennedy & Andrew O. Porter, *Air Pollution: Its Control and Abatement,* 8 Vand. L. Rev. 854 (1955).
293. W. Page Keeton et al., Prosser & Keeton on Torts §87, 619-20 (5th ed. 1984) [hereinafter Prosser].
294. *Id.* §88A, 630.
295. *See, e.g.,* Tiegs v. Watts, 954 P.2d 877 (Wash. 1998).
296. Prosser, *supra* note 293, §13, 67.
297. *Id.* at 71.
298. *See, e.g.,* Reynolds Metals v. Lampert, 316 F.2d 272, *rev'd*, 324 F.2d 465 (9th Cir. 1963), *cert. denied,* 376 U.S. 910 (1964).

or below the surface of the land.[299] Trespass offers the advantage that the statute of limitations begins when the interference causes substantial harm, but for a continuing trespass, it begins anew with each invasion.[300] The trespass doctrine is now an established remedy for aircraft overflights when there is a substantial interference with the use of land.[301] With modern pleading allowing alternative causes of action, private nuisance and trespass are usually both pleaded in a complaint. Trespass could be used by a plaintiff who can demonstrate reasonable and foreseeable damages from a defendant who engages in unauthorized use of the plaintiff's property interest in an underground pore space.[302] The ability to use trespass as a cause of action could be diminished, if a CCS regimen defined reasonable conduct and potential defendants could demonstrate that they acted within the permissible limits of the authorizing legal authority.[303] The limited case law on this subject deals primarily with secondary oil and gas recovery operations.[304]

Public nuisance developed historically as an omnibus criminal offense that allowed the government to prevent interference with the rights of the community.[305] This cause of action often involves the government as the plaintiff, but an individual may also use this doctrine. A private right-of-action based on public nuisance requires the plaintiff to have suffered damage over and beyond that suffered by the public at large, and the injury must be different in kind, rather than in degree, from the injury suffered by the public.[306] Personal injury or a business interference suffered by only a limited group within the community will probably support a claim for public nuisance.

On January 13, 2009, a North Carolina federal district court ruled that the emissions from the Tennessee Valley Authority's (TVA's) coal-fired power plants in Alabama and Tennessee constituted a public nuisance in North Carolina, based on state law, despite the plant's compliance with CAA permits issued by Alabama and Tennessee.[307] The court based its decision on the principles found in the *Restatement of Torts* §821B(1) and (2) and required TVA to abate emissions at a cost of more than $1 billion beyond the $3 billion TVA had already planned to spend to reduce its emissions.[308] The TVA's emissions were released up to 100 miles from North Carolina and were a small part of the pollution load in the state. Moreover, the pollutants that allegedly caused harm were secondary pollutants, formed from releases from many sources after undergoing chemical change in the atmosphere. The case involved a judge in a downwind state determining what controls should be required in an upwind state. The court's decision that the defendants were responsible for harm over a large area could have allowed many potential plaintiffs to sue for damages, with the liability of the defendants already established based on the doctrine of collateral estoppel.[309] The case was appealed to the U.S. Court of Appeals for the Fourth Circuit, which, on July 26, 2010, reversed, saying that the lower court's decision would encourage courts to use the vague public nuisance standards "to scuttle the nation's carefully created system for accommodating the need for energy production and the need for clean air."[310] The court went on to say: "It is difficult to understand how an activity expressly permitted and extensively regulated by both federal and state government could somehow constitute a public nuisance."[311] It would appear that the court's opinion could extend to any nuisance case involving an activity subject to a clearly articulated national regulatory policy.[312]

The first lawsuit to be filed to abate CO_2 emissions based on public nuisance was *Connecticut v. American Electric Power*,[313] in which eight states, the city of New York, and three environmental groups sued five electric utilities that are the five largest emitters of CO_2 in the United States. The plaintiffs sued the utilities seeking "abatement of [their] ongoing contribution to the public nuisance of global warming." The district court ruled this was a political question and dismissed the case.[314] The case was appealed to the U.S. Court of Appeals for the Second Circuit, where the procedural ruling was reversed, and the case was remanded to go forward for trial based on public nuisance under federal common law.[315] The court provided an exhaustive review of the law concerning nonjusticibility based on the political question doctrine, as well as the law of standing in its process of deciding the case is to go forward. The Second Circuit held that state, municipal, and private plaintiffs may seek injunctive relief for injuries alleged to be caused by climate change. Moreover, the court held that to have standing, the plaintiff need only show the defendant's discharge contributed to the kinds of injury suffered by the

299. Restatement of Torts (Second) §519; Prosser, *supra* note 293, §13, 82.
300. Prosser, *supra* note 293, §13, 83.
301. *Id.* at 81.
302. IOGCC, *supra* note 203, at 21.
303. *See* R.R. Comm'n of Texas v. Manziel, 361 S.W.2d 560, 568 (Tex. 1962). *But see* Mongrue v. Monsanto, 249 F.3d 422, 433 n.17 (5th Cir. 2001), where, in dicta, the court held that a valid permit did not necessarily bar a trespass action for disposal of hazardous waste using underground injection.
304. IOGCC, *supra* note 203.
305. Robert Abrams & Val Washington, *The Misunderstood Law of Public Nuisance: A Comparison With Private Nuisance Twenty Years After* Boomer, 54 Alb. L. Rev. 359, 362 (1990).
306. Prosser, *supra* note 293, §90, 643.
307. North Carolina ex rel. Cooper v. Tenn. Valley Auth., 593 F. Supp. 2d 812, 829-34 (W.D.N.C. 2009).
308. Tennessee Valley Authority, *TVA Files Appeal in North Carolina Lawsuit* (May 29, 2009), *available at* http://www.tva.gov/news/releases/aprjun09/ncappeal.htm (last visited July 20, 2009).
309. R. Trent Taylor, State of North Carolina v. TVA—*A New Era in Public Nuisance Law*?, 24 Toxics L. Rep. (BNA) 352 (Mar. 12, 2009).
310. North Carolina v. Tenn. Valley Auth. (TVA), 615 F.3d 291, 40 ELR 20194 (4th Cir. 2010).
311. *Id.* at 296.
312. *See* Stuart Parker, *Ruling Could Hinder Activists' Push for Climate, Emissions Nuisance Suits,* XXI Clean Air Rep. (Inside EPA) 16:22 (Aug. 5, 2010).
313. *See* Edward Lewis et al., *Following Second Circuit's Lead, Fifth Circuit Revives GHG Mass Tort Claims, available at* http://www.fulbright.com/index.cfm?fuseaction=publications.detail&site_id=494&pub_id=4197. The defendants are American Electric Power Co., American Electric Power Service Corp. (which does not generate CO_2 emissions), Southern Company, TVA, Xcel Energy, and Cinergy Corp.
314. Connecticut v. Am. Elec. Power Co., 406 F. Supp. 2d 265, 35 ELR 20186 (S.D.N.Y. 2005). *See* Lori R. Baker, *Global Warming: Attorneys General Declare Public Nuisance,* 27 U. Haw. L. Rev. 525 (2005).
315. Connecticut v. Am. Elec. Power Co., 582 F.3d 309, 393, 39 ELR 20215 (2d Cir. 2009).

plaintiff—there is no requirement to show specific causation. This does not mean, however, that specific causation is not required to prevail on a public nuisance claim. On August 2, 2010, the power companies petitioned for a writ of certiorari, asking the Supreme Court to reverse the Second Circuit's decision allowing the nuisance case to move forward.[316] In December 2010, the Court granted certiorari.[317] So far, 14 amicus briefs have been filed.

On October 16, 2009, the U.S. Court of Appeals for the Fifth Circuit unanimously reversed the district court decision in *Comer v. Murphy Oil*.[318] This case involves private property owners suffering damages from Hurricane Katrina, who sued Murphy Oil and dozens of other defendants, primarily energy firms. The plaintiffs claim defendants' emissions contribute to global warming that increases surface air and water temperatures that added to the intensity of Hurricane Katrina. Unlike the *Connecticut* case, which sought injunctive relief, the Mississippi property owners want compensatory and punitive damages, based on the Mississippi tort laws of public and private nuisance, trespass, negligence, unjust enrichment, fraudulent misrepresentation, and civil conspiracy. The Fifth Circuit three-judge panel ruled the plaintiffs have standing and adopted the Second Circuit's "fairly traceable" standard of causation for standing.[319] The court allowed the public and private nuisance, trespass, and negligence claims to go forward, but the unjust enrichment, fraudulent misrepresentation, and civil conspiracy claims lacked "prudential standing" and were dismissed.[320] However, on February 26, 2010, the ruling was vacated when the case was granted an en banc hearing. On May 28, 2010, the court said it could not rehear the matter, because so many judges had recused themselves that it lacked a quorum. Following court procedure, the appeal was dismissed, and the panel decision remains vacated, thus ending the plaintiffs' standing to sue for damages related to global warming.[321]

On September 30, 2009, the Federal District Court for the Northern District of California dismissed claims by the Native Village of Kivalina and the city of Kivalina, Alaska, against 24 energy and oil companies. The claims were based on the federal common law of nuisance.[322] The district court dismissed the *Native Village of Kivalina v. Exxon Mobil Corp.* case, which sought $400 million to allow the plaintiffs to relocate, based on lack of subject matter jurisdiction, due to the perceived political nature of global warming solutions, and because the plaintiffs could not prove the causation necessary to gain standing.[323] The case was appealed to the U.S. Court of Appeals for the Ninth Circuit, where it was still pending at the end of December 2010. Plaintiffs are seeking review of the political question doctrine, standing issues, and preemption of public nuisance claims by the CAA.

Two of the three nuisance cases concerning CO_2 emissions, discussed above, involve the federal common law of public nuisance.[324] The first significant air pollution cases based on federal common-law public nuisance were four cases decided between 1907 and 1916, in which the state of Georgia was successful in obtaining equitable relief for emissions released by the Tennessee Copper Company.[325] In the final decree, the Court imposed emission limits and monitoring requirements.[326] Many federal public nuisance cases have subsequently been decided, but it was not until about 1973 that the federal courts turned to the *Restatement (Second) of Torts* to determine the applicable rules for federal public nuisance cases.[327] In 1971, the Supreme Court ruled that states could bring public nuisance claims in the federal district courts, rather than using the Supreme Court as the only court with original jurisdiction for such cases.[328] Several district courts interpreted this case to allow municipalities to bring federal common-law nuisance claims.[329] The federal government also may bring nuisance-based cases.[330]

It is still not clear whether a private party may bring a federal common-law nuisance action, although the Third Circuit has allowed such an action.[331] In 1972 the Court, in *Milwaukee I*, held sewage discharge could be the subject of a federal common-law public nuisance action brought by a state in federal district court, because the existing statutes did not cover the plaintiff's claims and did not provide a remedy.[332] The Court warned, however, that "new federal laws and new federal regulations may in time pre-empt the field of federal common law of nuisance."[333] This came to pass, and the use of federal public nuisance in environ-

316. Doug Obey, *Utilities Target States' Standing in Bid to Reverse Climate Nuisance Suit,* XXI Clean Air Rep. (Inside EPA) 16:25 (Aug. 5, 2010); Steven D. Cook, *Four Electric Utilities Ask Supreme Court to Review Second Circuit Nuisance Decision,* 41 Env't Rep. (BNA) 1763 (Aug. 6, 2010).
317. *Connecticut*, 582 F.3d 309, *cert. granted*, No. 10-174 (U.S. Dec. 6, 2010).
318. 585 F.3d 855, 39 ELR 20237 (5th Cir. 2009).
319. *Id.* at 864-65.
320. *See* Steven Patrick, *Fifth Circuit Joins Second in Ruling Courts May Hear Cases on Damages From Warming,* 40 Env't Rep. (BNA) 2444 (Oct. 23, 2009).
321. Comer v. Murphy Oil USA, 607 F.3d 1049, 40 ELR 20147 (5th Cir. 2010). *See also Recusal Prompts Appellate Court to Drop Key Suit Allowing GHG Tort Claims,* XXI Clean Air Rep. (Inside EPA) 12:20 (June 10, 2010).
322. Native Village of Kivalina v. Exxon Mobil Corp., 663 F. Supp. 2d 863, 39 ELR 20236 (N.D. Cal. 2009).
323. *Id*. at 881-82. *See also* Lewis et al., *supra* note 313.
324. Connecticut v. Am. Elec. Power Co., 582 F.3d 309 (2d Cir. 2009); *Native Village of Kivalina*, 663 F. Supp. 2d 863.
325. Georgia v. Tenn. Copper Co., 206 U.S. 230 (1907); 237 U.S. 474 (1915); 237 U.S. 678 (1915); and 240 U.S. 650 (1916).
326. *Georgia*, 240 U.S. at 650-51.
327. Restatement (Second) of Torts, §§886A, 821B. *See, e.g.*, United States v. Ira Bushey & Sons, Inc., 363 F. Supp. 110, 120-21, 4 ELR 20071 (D. Vt. 1973), *aff'd*, 487 F.2d 1393 (2d Cir. 1973), *cert. denied,* 417 U.S. 976 (1974); United States v. Solvents Recovery Serv. of New England, 496 F. Supp. 1127, 1139-40, 10 ELR 20796 (D. Conn. 1980).
328. Ohio v. Wyandotte Chem. Corp., 401 U.S. 493, 495, 498-99, 1 ELR 20124 (1971).
329. *See, e.g.*, Connecticut v. Am. Elec. Power Co., 582 F.3d 309, 361-62 (2d Cir. 2009) (historical analysis); City of Evansville v. Ky. Liquid Recycling, Inc., 604 F.2d 1008, 9 ELR 20679 (7th Cir. 1979).
330. *See* United States v. Stoeco Homes, Inc., 498 F.2d 597, 611, 4 ELR 20390 (3d Cir. 1974).
331. *See* National Sea Clammers Ass'n v. City of New York, 616 F.2d 1222, 1233, 10 ELR 20155 (3d Cir. 1980), *vacated on other grounds,* Middlesex County Sewage Auth. v. Nat'l Sea Clammers Ass'n, 453 U.S. 1, 11 ELR 20684 (1981). *But cf.* Nat'l Audubon Soc. v. Dep't of Water, 869 F.2d 1196, 1205-06, 1211-12, 19 ELR 20198 (Reinhardt, J., dissenting) (9th Cir. 1988).
332. Illinois v. City of Milwaukee (Milwaukee I), 406 U.S. 91, 104, 107, 2 ELR 20201 (1972).
333. *Id*. at 107.

mental cases received a set back in *Milwaukee II*, when the Court ruled that the establishment of a comprehensive federal program for the control of water pollution subsequent to *Milwaukee I* precluded the federal courts from using federal common law to impose more stringent requirements than were imposed by the Federal Water Pollution Control Act (FWPCA).[334] While it would be difficult to claim that a comprehensive federal program for CO_2 exists at this time, the efforts of EPA to control CO_2 using the CAA may soon displace the use of federal common law of nuisance as a cause of action.

An important aspect of private nuisance, public nuisance, and trespass is that these causes of action may result in equitable relief for the successful plaintiff, such as abatement of the nuisance, or, in an extreme case, shutting down a business.[335] In addition, money damages may be awarded. If the harm to the community from granting equitable relief is significant, however, only money damages may be granted, and the defendant may obtain the equivalent of an easement to continue harmful conduct in return for paying appropriate damages.[336] These causes of action usually involve balancing the benefits to the public from the activity against the harm to the plaintiffs. But if plaintiffs prove significant harm and causation, they will likely recover damages for their injury, even if other injunctive relief is not granted.[337]

Negligence is the most common cause of action in the tort system. It requires a duty recognized by law that requires conformity to a standard; a breech of that duty that causes injury to a party; a close casual connection between the conduct and the injury (proximate cause); and an actual loss or damage.[338] For CCS cases, it will require showing a duty in an area that has little regulation. Ultimately, liability is going to rest on whether a reasonable care standard was met, which requires balancing the social utility of the conduct of the defendant against the risk to members of the public.[339] If a defendant's conduct was unreasonable, a plaintiff must further demonstrate that the defendant's conduct was the cause of the injury.

Strict liability (also known as liability without fault) is imposed on abnormally dangerous activities or conditions.[340] It is normally imposed as a social policy to shift the risk of loss to the entity that can best prevent a harmful event from occurring.[341] Under the *Restatement of Torts*, a balancing among six factors is required. To impose liability, the courts will balance: (1) the degree of risk of harm; (2) the likelihood that the harm will be substantial; (3) and the inability to eliminate the risk with reasonable care; against (4) whether the activity is common; (5) whether the activity is appropriate for a particular location; and (6) the value of the activity to the community in comparison to its risk.[342] The doctrine of strict liability has been applied to environmental contamination in 21 of 27 states that have considered this issue.[343] Two states, Texas and Wyoming, have rejected the doctrine.[344]

If the government takes an action that materially limits the use of property, an inverse condemnation action may be brought to recover the value of the property taken. There does not need to be a formal taking using the power of eminent domain, nor is physical occupancy required. This doctrine has been used successfully for damage to or loss of the use of property from nearby highway construction, and it has been used for damage caused by low-flying aircraft.[345]

Regardless of the legal theory pursued in a tort action involving CCS, proving causation may be a problem. Actions that cause harm may have occurred a decade or more before the case. There also may be problems of proof, if the injuries could be the result of exposure to many possible agents that may have been released from a variety of sources.[346] If the injury has multiple or an unknown etiology, proving a defendant was responsible can be difficult. Causation problems can also cut the other way. If causation cannot be definitively demonstrated, potential plaintiffs may be encouraged to gamble on a lawsuit.[347] The injuries that lead to lawsuits will involve injuries to property and/or injuries to health and the environment. CO_2 storage can also injure underground mineral, natural gas, petroleum, and water resources. It can induce seismic events or ground subsidence. However, the statute of limitations could run before the harm caused by a potential defendant is discovered. Courts usually combat this problem by imposing a discovery rule that runs from the time the plaintiff knew or should have known of the injury.[348]

334. Illinois v. Milwaukee (Milwaukee II), 451 U.S. 304, 306, 11 ELR 20406 (1981). The Court explicitly held the FWPCA displaced federal common law in *Nat'l Sea Clammers* (*see Nat'l Sea Clammers Ass'n*, 616 F.2d at 1221-22).
335. Prosser, *supra* note 293, §88A, 630.
336. *See* Boomer v. Atlantic Cement Co., 340 N.Y.S.2d 97 107-08 (N.Y. Sup. Ct. 1972), *aff'd*, 349 N.Y.S.2d 199 (N.Y. App. Div. 1973).
337. *See* Madison v. Ducktown Sulphur, Copper, and Iron Co., 113 Tenn. 331 (Tenn. 1904).
338. Restatement (Second) of Torts §282; Prosser, *supra* note 293, §30, 164.
339. *See* Restatement (Second) of Torts §§291, 292.
340. Prosser, *supra* note 293, §78, 545.
341. Prosser, *supra* note 293, §75, 536.
342. Restatement (Second) of Torts §520.
343. *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, 942-61 (2004).
344. Klass & Wilson, *Liability*, *supra* note 45, at 142 (citing Doddy v. Oxy USA, Inc., 101 F.3d 448, 462 (5th Cir. 1996); Jones v. Texaco, 945 F. Supp. 1037, 1050, 27 ELR 20517 (S.D. Tex. 1996); Wyrulec Co. v. Schutt, 866 P.2d 756, 761 (Wyo. 1993)).
345. United States v. Causby, 328 U.S. 256 (1946); Thomburg v. Port of Portland, 233 Ore. 178, 376 P.2d 100 (1962).
346. *See generally* Steve Gold, *Causation in Toxic Torts: Burdens of Proof, Standards of Persuasion, and Statistical Evidence,* 96 Yale L.J. 376 (1986); David Rosenberg, *The Causal Connection in Mass Exposure Cases: A "Public Law" Vision of the Tort System,* 97 Harv. L. Rev. 849 (1984); Bert Black & David E. Lilienfield, *Epidemiologic Proof in Toxic Tort Litigation,* 52 Fordham L. Rev. 732 (1984).
347. For examples of cases with questionable causation concerning swine flu litigation, see Arnold W. Reitze Jr., *Federal Compensation for Vaccination Induced Injuries*, 13 B.C. Envtl. Aff. L. Rev. 169, 181 (1986).
348. This issue is covered in more detail in Klass & Wilson, *Liability*, *supra* note 45, at 145.