Control of Geological Carbon Sequestration in the Western United States

by Arnold W. Reitze Jr. and Marie Bradshaw Durrant

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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. Part 1 of this Article, published last month, discussed how regional bodies and state governments are addressing the technical and legal problems that must be resolved in order to have a viable carbon storage program. Part 2 of the Article discusses the western state legal developments that encourage carbon storage.

I. Western States Carbon Capture-and-Storage Legislation

Coal production in the United States in 2009 totaled 1,075 million short tons; of this amount, 585 million short tons or 54% was produced in the eight westernmost states (including Alaska).[1] Wyoming dominates western coal production by producing 40.1% of the nation's coal, which is more than the combined total of all the Appalachian states.[2] In addition, Kansas has gone from two surface mines to one, which produces 0.017% of the nation's coal; Oklahoma has one underground mine and nine surface mines that produce 0.089% of the nation's coal; and Texas has 12 surface mines that produce 3.26% of the nation's coal.[3] Among the states in the western half of the United States, Idaho, Nebraska, Oregon, South Dakota, and Washington produce no coal, although some of these states have coal-burning electric-power plants.[4]

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1. U.S. Dep't of Energy (DOE), Energy Information Administration, *U.S. Coal Production by Coal-Producing Region and State, available at* http://www.eia.doe.gov/cneaf/coal/page/acr/tables2.html) [hereinafter EIA Production by State]; *Coal Production and Number of Mines by State and Mine Type, available at* http://www.eia.doe.gov/cneaf/coal/page/acr/table21.html [hereinafter EIA Mine Type].
2. EIA Production by State, *supra* note 1.
3. EIA Mine Type, *supra* note 1.
4. *Id.* While DOE lists these states as having no coal production, other data sources list small amounts of production from some of these states. This is discussed *infra* in material on specific states.

A. Alaska's Carbon Capture-and-Storage (CCS) Efforts

Alaska has only one coal mine, which produces 0.17% of the nation's coal.[5] The Usibelli Mine is near Healy and supplies coal to six power plants in Alaska and exports coal to South Korea and other Pacific countries.[6] The amount of coal in Alaska is the subject of considerable interest and ongoing research. There are vast reserves in the Arctic that are thought to hold as much as one-half the nation's coal. However, accessing these reserves is not currently economically feasible.[7] There are ongoing efforts to expand coal production in Alaska, primarily for export, but such efforts are the focus of environmentalists' opposition. The six power plants using coal have a total capacity of 136 megawatts (MWs), and none are larger than 50 MWs.[8] Alaska does not currently have any legislation on geologic CCS.

There are several coal-to-liquids projects underway in Alaska funded by the U.S. Department of Defense in an effort to develop synthetic fuels from coal.[9] In June of 2010, Cingranelli-Richards (CIRI) and Laurus Energy announced plans to produce syngas from deep underground coal in southcentral Alaska. The in-situ process produces synthetic gas from underground coal, separating carbon dioxide (CO_2) and other gases underground and storing them there. The proposed project would fuel a 100-MW power plant in southcentral Alaska.[10] If the proposed sequestration takes place, Alaska may soon be forced to deal with the legal issues of sequestration on a commercial scale.

B. Arizona's CCS Efforts

Arizona has one surface coal mine that produced a little under 7.5 million tons of coal in 2009.[11] There are six coal-fired power plants with 16 operating units in the state with a total capacity of 5,681 MWs.[12] The Navajo Generating Station has three 750-MW units totaling 2,250 MWs. At least 21% of this power is sent to California. In 2007, this station was ranked as the nation's eighth largest power plant emitter of CO_2.[13]

On March 25, 2009, the Arizona Department of Environmental Quality (ADEQ) and the U.S. Environmental Protection Agency (EPA) announced the first permit in the Southwest for a CCS project in Joseph City, Arizona. The Cholla pilot project planned a 20-day or less injection of 2,000 tons of CO_2 into an underground saline formation by the West Coast Regional Sequestration Partnership (WESTCARB), a regional partnership organized by the U.S. Department of Energy (DOE). The ADEQ permit is a temporary one-year aquifer protection permit that requires the holder to meet Arizona aquifer water quality standards and to use the best available technology. In addition, EPA issued a Safe Drinking Water Act Underground Injection Control permit, because it administers the program in Arizona. However, upon testing, WESTCARB determined that the saline aquifer was not sufficiently permeable and is now testing alternative sites for the CCS project.[14] This test project is part of the second phase of an Arizona CCS program. The first phase characterized the opportunities for CCS. The second phase involves small-scale field tests. The third phase, to run from 2008 to 2017, is to conduct large-volume carbon storage tests.[15]

Although three CCS pilot projects are currently underway in the state, Arizona does not yet appear to have any legislation specifically regulating CCS.[16] On April 26, 2010, Arizona's governor signed H.B. 2442 that forbids state agencies from regulating greenhouse gases (GHGs) without legislative approval.[17] This law may slow or stop efforts to implement CCS. In addition, Arizona has said the state will not participate in current efforts to implement the Western Climate Initiative's cap-and-trade program, which removes a major incentive for utilities to participate in a CCS program.[18] However, on December 1, 2010, EPA included Arizona as one of 13 states that must adjust its state implementation plan (SIP) to apply prevention of significant deterioration (PSD) provisions to GHG emissions. Arizona was ordered by EPA to include GHGs as one of the specific pollutants regulated by the PSD program by December 22, 2010.[19]

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5. EIA Mine Type, *supra* note 1.
6. Source Watch, *Alaska and Coal*, http://sourcewatch.org/index.php?title=Alaska_and_coal (last visited Mar. 11, 2011).
7. *See* David Coil et al., Ground Truth Trekking, Quantifying Coal: How Much Is There?, http://www.groundtruthtrekking.org/Issues/AlaskaCoal/HowMuchCoal.html.
8. Source Watch, *Alaska and Coal*, *supra* note 6.
9. *Id.*
10. CIRI Press Release, Laurus Energy and Ciri Form Joint Venture (June 8, 2010), *available at* http://www.ciri.com/content/company/NewsDetails.aspx?ID=743.
11. EIA Mine Type, *supra* note 1.
12. Source Watch, *Category: Existing Coal Plants in Arizona,* http://www.sourcewatch.org/index.php?title=Category:Existing_coal_plants_in_Arizona (last visited Mar. 22, 201a). The plants are Abitibi Snowflack Power Plant, Apache Generating Station, Cholla Generating Station, Coronado Generating Station, H. Wilson Sundt Generating Station, and the Navajo Generating Station.
13. *See* Source Watch, *Navajo Generating Station,* http://sourcewatch.org/index.php?title=Navajo_Generating_Station (last visited Mar. 22, 2011); Environment Arizona, *America's Biggest Polluters: Carbon Dioxide Emissions From Power Plants 2007*, http://www.environmentarizona.org/reports/global-warming/global-warming-program-reports/americas-biggest-polluters-carbon-dioxide-emissions-from-power-plants-in-2007 (last visited Mar. 22, 2011).
14. WESTCARB, *Arizona Utilities CO_2 Storage Pilot—Cholla Site*, http://www.westcarb.org/AZ_pilot_cholla.html (last visited Mar. 22, 2011).
15. William H. Carlile, *EPA, State Issue One-Year Permit for Pilot Carbon Sequestration Project,* 40 Env't Rep. (BNA) 719 (Mar. 27, 2009).
16. *See* Lee Allison, *Carbon Capture & Storage Legislation*, Arizona Geology, Blog of the State Geologist of Arizona (July 26, 2010), http://arizonageology.blogspot.com/2010/07/carbon-capture-storage-legislation.html (last visited Mar. 22, 2011).
17. *Arizona Strips Agencies of Greenhouse Gas Authority,* 41 Env't Rep. (BNA) 1026 (May 7, 2010).
18. William H. Carlile, *State Agency Issues Proposed Rule to Establish Cap-and-Trade Program,* 41 Env't Rep. (BNA) 1150 (May 21, 2010).
19. Action to Ensure Authority to Issue Permits Under the Prevention of Significant Deterioration Program to Sources of Greenhouse Gas Emissions: Finding of Substantial Inadequacy and SIP Call; Final Rule, 40 C.F.R. pt. 52 (Docket No. EPA-HQ-OAR-2010-0107).

C. California's CCS Efforts

There is no coal mined in California.[20] California's coal-fired electric power comprises less than 1% of the state's generating capacity. There are eight plants with a total of 10 units that have a combined capacity of 439 MWs; five plants have a capacity greater than 54 MWs.[21] However, California utilities own about 3,500 MWs of capacity in five coal-burning plants located in Arizona, Nevada, New Mexico, and Utah.[22] In 2007, the California Energy Commission (Commission) banned the signing of new contracts with out-of-state coal-fired power plants by municipal and investor-owned electric utilities.[23] California limits new coal-fired power plants to 1,100 pounds of CO_2 per megawatt-hour (MWh).[24] However, by statute, geologically stored CO_2 does not count as a power plant emission in terms of meeting GHG emission performance standards.[25] The framework for California's response to climate change was established in 2006 with the enactment of AB 32, the California Global Warming Solutions Act of 2006.[26] The aim of the Act is to reduce GHG emissions, and some experts see CCS as a "critical technology pathway for the state of California in achieving steep GHG reductions."[27] AB 32 is discussed later in this Article.

California law requires the Commission to adopt a biannual integrated energy policy report (IEPR) containing an overview of the major energy trends and issues facing the state in three key areas: (1) electricity and natural gas markets; (2) transportation fuels, technologies, and infrastructure; and (3) public interest energy strategies.[28] In 2006, the California Legislature unanimously passed Assembly Bill 1925, An Act Relating to Energy (AB 1925), which adds geologic carbon sequestration as a topic to be addressed in the Commission's biannual IEPR.[29] AB 1925 requires that on or before November 1, 2007:

> [T]he State Energy Resources Conservation and Development Commission, in coordination with the Division of Oil, Gas, and Geothermal Resources of the Department of Conservation and the California Geological Survey, shall submit a report to the Legislature containing recommendations for how the state can accelerate adoption of cost-effective geologic sequestration strategies for the long-term management of industrial carbon dioxide. In formulating recommendations, the commission shall meet with representatives from industry, environmental groups, academic experts, and other government officials, with expertise in indemnification, subsurface geology, fossil fuel electric generation facilities, advanced carbon separation and transport technologies, and greenhouse gas management.[30]

AB 1925 mandates carbon sequestration issues be included in the report.[31] AB 1925 also requires the IEPR to support research and development in the following areas.

(1) Identify and characterize state geological sites that potentially are appropriate for long-term storage of CO_2.

(2) Evaluate the comparative economics of various technologies for capture and sequestration of CO_2.

(3) Identify technical gaps in the science of sequestration of CO_2 to be prioritized for further analysis.

(4) Evaluate the potential risks associated with geologic sequestration of CO_2, including leakage resulting from carbonates and other dissolved minerals.

(5) Evaluate the potential risks if geologically sequestered CO_2 leaks into aquifers.

(6) Evaluate, and to the extent feasible quantify, the potential liability from the leakage of geologically sequestered CO_2 and potentially responsible parties.[32]

As mandated by AB 1925, in February 2008, the Commission and California Department of Conservation released a 139-page joint report entitled *Geologic Carbon Sequestration Strategies for California: Report to the Legislature* (Joint Report).[33] The 10 chapters of the report address the following issues: (1) Role of Carbon Sequestration in Climate Change Mitigation in California; (2) Key Implementation Issues; (3) Potential for Capture and Geologic Sequestration; (4) Capture Technologies; (5) Site Characterization; (6) Monitoring and Verification; (7) Risks and Risk Management; (8) Remediation and Mitigation of CO_2 Leakage; (9) Economic Considerations; and (10) Regulatory and Statutory Issues.[34]

The executive summary of the report makes five recommendations and calls for a more comprehensive analy-

20. EIA Production by State, *supra* note 1.
21. Source Watch, *California and Coal,* at 5, http://www.sourcewatch.org/index.php?title=California_and_coal#Existing_coal_plants (last visited Mar. 22, 2011). The plants are: ACE Cogeneration (108 MWs), Port of Stockton District Energy Facility (54 MWs), Stockton Cogeneration (60 MWs), Mt. Poso Cogeneration (62 MWs), and Argus Cogeneration (55 MWs).
22. *Id.*
23. *Id. See* California S.B. 1368; Cal. Pub. Util. Code §8341(d)(5) (West 2010).
24. *Id.* Based on California's S.B. 1368. The limit is derived from the emissions level of a combined-cycle natural gas base-load generator.
25. *See* Cal. Pub. Util. Code §8341(d)(5) (West 2010).
26. *See* California Air Resources Board, *AB 32 Fact Sheet—California Global Warming Solutions Act of 2006* (Sept. 25, 2006).
27. S. Julio Friedman, *Reducing Emissions in California Through Carbon Capture and Sequestration,* http://www.arb.ca.gov/research/seminars/friedmann/friedmann.htm (last visited Mar. 30, 2011).
28. Cal. Pub. Res. Code §25302(a) (West 2010).
29. Cal. Pub. Res. Code §25302 (West 2010). Section 25302 was added in 1974 and has been amended by multiple session laws, including §1 of Stats. 2006, c. 471 (A.B. 1925). The text of AB 1925 is found in historical and statutory notes for §25302. Section 1 of Stats. 2006, c. 471(a)(3) (A.B. 1925) requires the Commission to include carbon sequestration in its biannual report.
30. Section 1 of Stats. 2006, c. 471(a)(1) (A.B. 1925).
31. Section 1 of Stats. 2006, c. 471(a)(2)(A)-(C) (A.B. 1925).
32. Section 1 of Stats. 2006, c. 471(b) (A.B. 1925).
33. California Energy Commission & California Department of Conservation, Geologic Carbon Sequestration Strategies for California: Report to the Legislature (Feb. 2008), *available at* http://www.energy.ca.gov/2007publications/CEC-500-2007-100/CEC-500-2007-100-CMF.PDF.
34. *Id.* at v-viii.

sis to be completed in 2010. The five recommendations are the following:

1. Over the next three years, any state planning and other analyses involving energy or greenhouse gas emissions reduction strategies, as appropriate, should include consideration of carbon capture and sequestration options. Improved cost estimates should be developed, and policy makers at all levels of government should consider them an appropriate proxy for the long-term value of CO_2 reduction.

2. Further examination is needed of the scenarios for carbon capture and sequestration adoption identified in this report as early opportunities, based on potentially close-to-favorable business cases. These opportunities may have greater value than as niche applications and may facilitate creation of an in-state market for CO_2 by demonstrating enhanced oil and gas production.

3. Demonstration projects in the United States and around the world over the next three years will provide key data to set carbon capture and sequestration policy. They should be facilitated and carefully studied, and may provide early insight into public and property owner's concerns about risks.

4. California's power imports encourage consideration of carbon capture and sequestration in a regional context. Coordinated investigations of carbon capture and sequestration for power plants should take place involving other states in the Western Electricity Coordinating Council region. This should be done in the context of recognizing the connection between regional climate change and electricity generation objectives and involve consideration of how carbon responsibility should "flow" with electricity.

5. Regulatory and statutory ambiguities and barriers identified in this report must be addressed, potentially through efforts that cut across the agencies that will ultimately be involved in regulating carbon capture and sequestration, from surface facilities through injection to sequestration and verification of climate change mitigation. These efforts would include evaluating the need for protocols and, as applicable, drafting them. This would include protocols for site characterization, monitoring and verification, and contingency plans for remediating leakage.[35]

1. California Assembly Bill 32: The California Global Warming Solutions Act and Scoping Plan

In 2006, the California Legislature passed AB 32, the California Global Warming Solutions Act of 2006.[36] The goal of AB 32 is to reduce GHG emissions to 1990 levels by 2020 by having the California Air Resources Board (CARB) adopt concrete GHG reduction measures by 2011.[37] In 2010, AB 32 was targeted by Valero Energy Corporation and other oil companies that succeeded in putting a voter initiative on the November 2010 ballot. The initiative would have suspended implementation of AB 32 until the state's unemployment rate remained at 5.5% for a year, which has occurred only once in the past 30 years.[38] This effort was seen by many as an initiative on AB 32 as well as Californians' commitment to seriously addressing climate change.[39] The initiative failed, with 61% voting against it. However, there are now concerns that another initiative on the same ballot, which was approved (Proposition 26), may still act to curb the effectiveness of AB 32.[40] Proposition 26 requires that certain state and local fees be approved by a two-thirds legislative vote. Fees include charges that address adverse impacts on society or the environment caused by the fee-payer's business. This proposition passed with 52.5% of the vote and may apply to a cap-and-trade program.[41] The measure will make it more difficult to impose regulatory fees, such as environmental cleanup fees, and it will increase the uncertainty concerning whether a measure is a tax or a fee, which can be expected to lead to litigation. This Proposition was supported by the tobacco, alcoholic beverage, and oil industries.[42] However, CARB has signaled it does not believe Proposition 26 will derail cap and trade,[43] and on December 16, CARB approved the cap-and-trade and GHG emissions reduction program outlined by AB 32.[44]

35. *Id.* at 10.
36. Cal. Health & Safety Code §38500 et seq. (West 2010).
37. Cal. Health & Safety Code §38550 (West 2010). *See also* California Environmental Protection Agency, Air Resources Board, Assembly Bill 32: Global Warming Solutions Act, http://www.arb.ca.gov/cc/ab32/ab32.htm (last visited Mar. 22, 2011) [hereinafter CEPA AB 32].
38. Carolyn Whetzel, *Economists Conclude Climate Policies Will Have Little Impact on State Economy,* 41 Env't Rep. (BNA) 959 (Apr. 30, 2010).
39. Margot Roosevelt, *Prop. 23: Why Did Valero Launch a Campaign Against California's Climate Law?*, L.A. Times, Oct. 31, 2010, http://latimesblogs.latimes.com/greenspace/2010/10/prop-23-valero-global-warming-oil-refineries.html (last visited Mar. 30, 2011); *Prop. 23 Battle Marks New Era in Environmental Politics*, L.A. Times, Nov. 4, 2010, http://www.latimes.com/news/local/la-me-global-warming-20101104,0,4277096.story (last visited Mar. 22, 2011).
40. *See* Margot Roosevelt, *Lawyers, Lobbyists, Politicians Scramble to Determine Impact of Prop. 26*, L.A. Times, Nov. 14, 2010, http://www.latimes.com/news/local/la-me-prop26-impact-20101115,0,2819277,full.story (last visited Mar. 22, 2011).
41. Ballotpedia, *California Proposition 26, Supermajority Vote to Pass New Taxes and Fees (2010)*, http://www.ballotpedia.org/wiki/index.php/California_Proposition_26,_Supermajority_Vote_to_Pass_New_Taxes_and_Fees_(2010) (last visited Mar. 24, 2011). *See also* Carolyn Whetzel, *Statew's Voters Reject Ballot Measure to Stall Implementation of Climate Policies,* 41 Env't Rep. (BNA) 2476 (Nov. 5, 2010).
42. Carolyn Whetzel, *Voters Approve Ballot Measure to Require Two-Thirds Vote on State Regulatory Fees,* 41 Env't Rep. (BNA) 2477 (Nov. 5, 2010).
43. *See* Margot Roosevelt, *Lawyers, Lobbyists, Politicians Scramble to Determine Impact of Prop. 26*, L.A. Times, Nov. 14, 2010, http://www.latimes.com/news/local/la-me-prop26-impact-20101115,0,2470740.story (last visited Mar. 13, 2011).
44. *See* CARB, Cap-and-Trade, http://www.arb.ca.gov/cc/capandtrade/capandtrade.htm (last visited Mar. 29, 2011). However, the cap-and-trade program suffered an additional setback in March, when the California Superior Court for San Francisco County ruled that CARB did not adequately consider the possibility that other alternatives to cap and trade, such as a carbon tax, could be used to meet California's GHG reduction goals. *As-*

Several of AB 32's specific mandates have also been completed by CARB. For example, CARB was required to develop a scoping plan to identify the maximum technologically feasible and cost-effective reductions for GHG sources.[45] "In developing its plan, the state board [CARB] shall identify opportunities for emission reductions measures from all verifiable and enforceable voluntary actions, including, but not limited to, carbon sequestration projects and best management practices"[46]

This plan, approved by CARB on December 12, 2008, identifies regulations, market mechanisms, and other actions for achieving GHG reductions.[47] CARB is to identify a numeric statewide emission reductions goal needed to reach 1990 GHG levels by 2020.[48] In December 2007, CARB approved a 2020 emission limit of 427 million tons of CO_2 equivalent.[49]

AB 32 requires the adoption of a mandatory GHG reporting and verification regulation for GHG emissions.[50] In 2007, CARB adopted a regulation requiring the largest GHG emitters to report and verify their emissions.[51] AB 32 also requires CARB to identify and adopt regulations that will give credit for Discrete Early Actions by January 1, 2010.[52] In 2007, CARB developed a list of nine discrete actions to be taken.[53] CARB also recommended 44 actions for approval for Early Action credit (which, unlike the Discrete Early Actions, may or may not be regulatory).[54] CARB estimates that these early actions have the potential to contribute up to 25% of the emissions reductions required to meet the 2020 goal.[55] In February 2008, CARB approved a policy statement encouraging early actions and establishing a procedure for project proponents to submit quantification methods to receive credit for voluntary actions.[56]

CARB's approved Scoping Plan supports CCS technology.[57] After addressing the carbon reduction benefits of power plants equipped with CCS technology, the Scoping Plan encourages California to support near-term advancement of the technology and ensure an adequate framework is in place to provide credit for CCS projects when appropriate (see the discussion of the CCS Panel *infra* at Part I.C.2.).[58] The Scoping Plan includes a brief paragraph regarding California's involvement with the WESTCARB, which is a public-private partnership "conducting technology validation field tests, identifying major sources of CO_2 in its territory, assessing the status and cost of technologies for separating CO_2 from process and exhaust gases, and determining the potential for storing captured CO_2 in secure geologic formations."[59]

AB 32 also called for the creation of an Economic and Technology Advancement Advisory Committee (ETAAC) to advise CARB "on activities that will facilitate investment and implementation of technological research and development opportunities."[60] In February 2008, ETAAC released its *Recommendations of the Economic and Technology Advancement Advisory Committee Final Report: Technologies and Policies to Consider for Reducing Greenhouse Gas Emissions in California* (2008 ETAAC Report).[61] The Report exclusively addresses CCS technology in connection with natural gas and energy technology and promotes CCS as a significant opportunity for emissions reductions[62]:

> Demonstration of CCS in geological formations is a key opportunity for California to benefit from national and international partnerships. Broad commercial deployment of technology for CCS in geological formations faces significant challenges. Nevertheless, it offers a potential opportunity for achieving long term reductions in GHG emissions, especially on a national and global scale.[63]

The Report calls for implementing CCS demonstration projects by 2012 with full commercialization by 2020. It identifies California's CCS potential as 5.2 giga-tons of CO_2 storage in oil and natural gas fields, with potentially even greater capacity in deep saline formations, and cites estimates that CCS could represent 15-55% of the cumulative international mitigation effort needed to reduce GHGs

sociation of Irritated Residents v. CARB, Statement of Decision: Order Granting in Part Petition for Writ of Mandate, CPF-09-509562 (Mar. 18, 2011), *available at* http://cdn.law.ucla.edu/SiteCollectionDocuments/Environmental%20Law/Court%27s%20Final%20Order%203%2017%2011.pdf. This holding will likely cause additional delays to implementation of AB 32.

45. Cal. Health & Safety Code §38561 (West 2010). In addition to calling for a scoping plan, AB 32 also convened an Environmental Justice Advisory Committee (EJAC) to help the ARD develop the scoping plan and implementation of AB 32. Cal. Health & Safety Code §38591 (West 2010).
46. Cal. Health & Safety Code §38561(f) (West 2010).
47. CARB, *Climate Change Scoping Plan: A Framework for Change* (Dec. 2008), *available at* http://www.arb.ca.gov/cc/scopingplan/scopingplan.htm (last visited Nov. 22, 2010) [hereinafter CARB Scoping).
48. Cal. Health & Safety Code §38550 (West 2010).
49. *See* CARB Scoping, *supra* note 47, at 5.
50. Cal. Health & Safety Code §38550 (West 2010).
51. *See* CARB Scoping, *supra* note 47, at 5; *see also* California Environmental Protection Board: Air Resources Board, Mandatory Greenhouse Gas Emissions Reporting, http://www.arb.ca.gov/cc/reporting/ghg-rep/ghg-rep.htm (last visited Mar. 23, 2011).
52. Cal. Health & Safety Code §38560.5 (West 2010).
53. *See* CARB, *Early Action Items: Discrete Early Actions*, http://www.arb.ca.gov/cc/ccea/ccea.htm (last visited Mar. 24, 2011). The nine actions are: (1) a low carbon fuel standard; (2) landfill methane capture; (3) reductions from mobile AC; (4) semiconductor reduction; (5) SF6 Reductions; (6) high GWP consumer products; (7) heavy-duty measures; (8) tire pressure program; and (9) shore power.
54. CARB, Final Staff Report: Expanded List of Early Action Measures to Reduce Greenhouse Gas Emissions in California Recommended for Board Consideration, at 5 (Oct. 2007), *available at* http://www.arb.ca.gov/cc/ccea/ccea.htm.
55. *Id*. at 2.
56. CARB, Policy Statement on Voluntary Actions to Reduce Greenhouse Gas Emissions (Feb. 28, 2008), *available at* http://www.arb.ca.gov/cc/scopingplan/voluntary/voluntary.htm (last visited Nov. 24, 2010).
57. CARB Scoping, *supra* note 47, at 64-65. The Scoping Plan also addresses in-depth potential efforts to reduce CO_2 through terrestrial sequestration (trees) and other natural carbon sinks.
58. *Id.*
59. *Id.*
60. CARB, *Economic and Technology Advancement Advisory Committee*, http://www.arb.ca.gov/cc/etaac/etaac.htm (last visited Mar. 24, 2011).
61. California Economic and Technology Advancement Advisory Committee, Recommendations of the Economic and Technology Advancement Advisory Committee Final Report: Technologies and Policies to Consider for Reducing Greenhouse Gas Emissions in California (2008), *available at* http://www.arb.ca.gov/cc/etaac/etaac.htm.
62. *Id*.
63. *Id.* at 5-21.

by 2100. There are additional benefits from reduction of criteria pollutants like nitrous oxides (NO_x) and sulfur dioxide (SO_2). Implementation of CCS technology was identified as being difficult, with federal and state agencies as well as the private sector listed as the responsible parties for implementing CCS technology.[64]

Problems associated with CCS technology include the small size and number of current demonstration projects compared with the scale necessary to mitigate CO_2 emissions. Commercialization of CCS technologies will involve the initial high cost and potential risks of first-generation systems and the need to develop the required infrastructure. Moreover, potential for leakage, both at the general technological level and at potential storage sites, must be identified and mitigation measures created. "Regulatory uncertainties and legal issues regarding property rights and liability are still significant barriers."[65] In addition, there is relatively little experience to date at the federal or state level in combining CO_2 capture, transport, and storage into a fully integrated CCS system.

The 2008 ETAAC Report proposes continuing partnerships like DOE's WESTCARB program and taking advantage of international opportunities if presented.[66] Similarly, California should continue to work with the federal government to address legal, regulatory, and safety barriers associated with CCS, especially long-term liability issues like insurance and the appropriate balance between taxpayer involvement and the private sector.[67] The Report also cites the low likelihood of CCS profitability without a price signal on carbon.[68]

The ETAAC's subsequent December, 14, 2009, report, *Advanced Technology to Meet California's Climate Goals: Opportunities, Barriers, and Policy Solutions*, only mentions CCS technology once in reference to programs eligible for federal funding and then references the 2008 ETAAC Report for further information on CCS technology.[69]

2. Integrated Energy Policy and CCS Panel Reports

In addition to the 2008 Report associated with AB 1925 and the Scoping Plan and various committee reports associated with AB 32, the Energy Commission has produced or contracted for several other reports regarding geologic carbon sequestration in the state.

As required by statute,[70] on December 19, 2009, the Commission released its 2009 Integrated Energy Policy Report (2009 IEPR).[71] The 2009 IEPR claims significant changes in the carbon sequestration field have occurred since the release of the 2008 Report on Carbon Sequestration associated with the 2007 IEPR. For example, the 2009 IEPR claims California technology developers and policymakers have expanded their view of CCS applications from coal and petroleum to include natural gas and refinery gases, the main fossil fuels employed in the state's power plants and industrial facilities.[72] Similarly, new and improved energy reducing solvents for post-combustion closed-loop absorption capture systems are being offered and tested, which will decrease the price of CO_2 capture.[73] Developers are also working on competing systems, which will aid the commercial and economic development of CCS technology.[74] Since the release of the 2007 IEPR, oxy-combustion CO_2 capture has been tested "at ten times the size of previous pilot units," and pre-combustion CO_2 capture systems are being proposed in commercial plants based on solid fuel gasification.[75]

The 2009 IEPR also includes recent DOE activities that may affect CCS in the state. The IEPR Report states:

> The U.S. Department of Energy (DOE) recently solicited proposals for large-scale industrial CCS projects at facilities fueled chiefly by noncoal energy; it is poised to award more than $1.3 billion in project co-funding authorized by the ARRA of 2009. Further, DOE has added funds to its cooperative agreement with the Energy Commission for the West Coast Regional Carbon Sequestration Partnership (WESTCARB; a public-private research collaborative involving more than 80 organizations) to work with PG&E to conduct an engineering-economic evaluation of CCS at natural gas combined cycle plants in California. WESTCARB also continues to work with the California Geological Survey and industry partners to characterize California deep saline formations suitable for commercial-scale CO_2 storage; two CO_2 storage field tests in the Central Valley are planned.[76]

In addition to physical projects and technologies, the 2009 IEPR stresses the need for California to clarify and solidify a legal/regulatory regime to accommodate and encourage CCS development. The 2009 IEPR identifies several key regulatory issues. First, the report calls for California to join other states in establishing rules regarding the ownership of and title to the "pore space" the captured CO_2 is to be stored in.[77] These regulations should address ownership of the pore space, ability to transfer pore space rights and dominance of those right relative to surface and mineral rights, access procedures for adjoining pore

64. *Id.* at 5-21.
65. *Id.* at 5-21 through 5-22.
66. *Id.* at 5-22.
67. *Id.*
68. *Id.* at 5-23.
69. CARB, California Economic and Technology Advancement Advisory Committee, Advanced Technology to Meet California's Climate Goals: Opportunities, Barriers & Policy Solutions 116 (2009), *available at* http://www.arb.ca.gov/cc/etaac/meetings/etaacadvancedtechnologyfinalreport12-14-09.pdf.
70. Cal. Pub. Res. Code §25302(a) (West 2010).
71. California Energy Commission, 2009 Integrated Energy Policy Report (Dec. 2009), *available at* http://www.energy.ca.gov/2009publications/CEC-100-2009-003/CEC-100-2009-003-CMF.PDF.
72. *Id.* at 108.
73. *Id.*
74. *Id.*
75. *Id.* at 108-09.
76. *Id.* at 109.
77. *Id.*

properties, and potential long-term liability issues.[78] Also needing attention are the procedure to determine which permitted enhanced oil recovery (EOR) operations may become long-term CO_2 projects and the responsibilities and jurisdiction of the California Environmental Quality Act for: (1) siting power plants with CCS technology, pipelines, and offsite geologic storage of CO_2; (2) monitoring, reporting, and remediation of stored CO_2; and (3) rules for offshore (sub-seabed) CO_2 projects.[79]

In response to the 2009 IEPR, a Carbon Capture and Storage Review Panel (CCS Panel) was formed in April 2010. The CCS Panel is tasked to: (1) frame specific policies addressing the role of CCS in meeting the state's energy needs and GHG reduction goals; (2) review CCS policy frameworks used elsewhere, and identify gaps, alternatives, and applicability in California; and (3) develop specific recommendations on CCS to be reported to the California Energy Commission, Public Utilities Commission, and CARB by November 30, 2010.[80] On December 13, 2010, the CCS Panel released a report titled *Draft Recommendations by the California Carbon Capture and Storage Review Panel* (CCS Recommendations).[81] The CCS Recommendations identify CCS as an important mitigation strategy to help California meet the AB 32 GHG reduction goals and suggest measures California should adopt to encourage CCS and make it a profitable venture in California.

> If CCS is to play a role in achieving California's greenhouse gas reduction goals, a clear and consistent regulatory and policy framework must be established. The framework should clearly establish the roles and authorities of the involved state agencies, facilitate and streamline permitting processes, and serve the public's interest in assuring climate change mitigation goals are met while protecting the environment and human health and safety.
>
> A statutory or regulatory framework for CCS must be clear, transparent, flexible and adaptable. There is a need for a clearly articulated state policy which recognizes the value of CCS technology as [*sic*.] marketable commodity and as a GHG reduction strategy. Lastly, there must be clear rules on permitting and regulating CCS projects. Consistent reporting protocols should be established for monitoring, measurement and verification of the volume of GHG emissions sequestered, and a GHG accounting method should be established that gives carbon credits to CCS development projects which help industry satisfy their AB 32 obligations.[82]

78. *Id.* at 109-10.
79. *Id.*
80. CARB, *California Carbon Capture and Storage*, http://www.climatechange.ca.gov/carbon_capture_review_panel/index.html (last visited Mar. 24, 2011).
81. CARB CCS Review Panel, Draft Recommendations by the California Carbon Capture and Storage Review Panel (Dec. 2010), *available at* http://www.climatechange.ca.gov/carbon_capture_review_panel/meetings/2010-12-15/2010-12-13_Draft_Recommendations_by_the_California_Carbon_Capture_and_Storage_Review_Panel.pdf [hereinafter CCS Recommendations].
82. CCS Recommendations, *supra* note 81, at 1.

The CCS Recommendations conclude that CCS is beneficial to California and encourage measures to facilitate rapid yet safe development and deployment of CCS. Going a step further than the ETAAC recommendation of CCS as a long-term possibility, the CCS Recommendations call on CARB to set a short-term goal to expedite the use of CCS, before 2020 if possible.[83] The main recommendations of the report are:

> 1. The State should clearly identify CCS as a measure that can reduce carbon and that allows carbon credits under a state-administered cap-and-trade program. To that end, the ARB should develop GHG reporting protocols for CCS projects.
> 2. The State should consider legislation authorizing the use of eminent domain for CO_2 pipelines that are not owned or operated by public utilities. The legislation should clarify the ownership of "pore space" and ensure that property owners are justly compensated for the use of their land for CCS development. Alternately, the State should establish a process by which the rights of property owners are fairly adjudicated.
> 3. The State should consider legislation that identifies either the CPUC [California Public Utilities Commission] or the State Fire Marshall as the lead agency for regulating CO_2 pipelines.
> 4. The State should identify a lead agency for administering post-closure operations, and for establishing monitoring, measurement and verification (MMV) requirements for permitting CCS projects.
> 5. The State should consider legislation establishing a fee-based fund structure to be used for long-term stewardship.
> 6. The [CCS] Panel endorses the need for a well thought-out and well-funded public outreach program to ensure that the risks and benefits of CCS technology are effectively communicated to the public.
> 7. The State should establish and administer a program to insure against the long-term risk of irregular CO_2 behavior in the reservoir, in concert with the federal government.
> 8. The State should consider legislation designating the Energy Commission as the lead [agency for] permitting projects for all CCS projects (both stand-alone and retrofit projects).
> 9. The CEC should consult with the responsible permitting agencies in carrying out its responsibilities. Specifically, the CEC should consult with the Division of Oil, Gas and Geothermal Resources (DOGGR) for its technical expertise

83. *Id.* at 7.

associated with oil and gas development and incorporate the DOGGR requirements into the CEC permit process.

10. The State of California should evaluate the pending EPA regulations and determine whether and who should seek "primacy" for permitting CCS wells.
11. The State should establish one set of performance and remediation standards for geologic storage projects that demonstrate, with a high degree of confidence, 99 percent retention over a thousand years. These standards should measure the quantity and permanence of CO_2 sequestered.
12. Methodology to stimulate early mover CCS projects should be considered.[84]

Specific recommendations for each of these measures are outlined in the full report, including recommendations to treat CO_2 as a commodity rather than a pollutant or hazardous liquid,[85] conduct further studies on pore-space ownership,[86] develop a trust fund for long-term monitoring,[87] push for a federal system governing long-term liability,[88] authorize eminent domain for CO_2 pipelines,[89] and provide funding mechanisms and public education to promote CCS development in California.[90]

With the December 16, 2010, CARB vote approving a cap-and-trade program that will be the largest of any in the United States, California moves a step closer to placing a price on carbon emissions.[91] The combination of the favorable CCS Recommendations and the financial incentives provided by the cap-and-trade program strengthen California's potential as a leader for CCS.

3. Geologic Carbon Sequestration Potential in California

Another pertinent publication released by the California Energy Commission in December 2006 is *An Overview of Geologic Carbon Sequestration Potential in California* (Overview).[92] The Overview is a preliminary assessment by the California Geological Survey (CGS) of geologic carbon sequestration potential in California. This assessment was part of WESTCARB and "involved identifying and characterizing porous and permeable rock formations and defining areas within the state's sedimentary basins that may be geologically suitable for carbon sequestration in saline aquifers or producing or abandoned oil and gas reservoirs."[93]

The Overview examines CCS technology and the WESTCARB project; experimental projects to complete CCS goals; and the results of California's various experiments. The Overview concludes:

> A preliminary screening of California's sedimentary basins indicates that at least 27 basins possess varying potential for CO_2 sequestration. These basins comprise an aggregate area of more than 98,420 km^2 (38,000 sq. mi.) . . . .
>
> . . . .
>
> Currently, the most promising basins for potential CO_2 sequestration include the San Joaquin, Sacramento, Ventura, Los Angeles, and Eel River basins. Smaller marine basins such as the Salinas, La Honda, Cuyama, Livermore, Orinda, and Sonoma basins are also promising but more restricted in terms of size and available geological information. Several terrestrial basins, including the large Salton Trough, may present some opportunities for CO_2 sequestration and cannot be excluded from consideration given the limited currently available information.
>
> . . . .
>
> Preliminary estimates of CO_2 storage capacity of the ten largest basins identified in this assessment have placed the storage capacity of saline aquifers between 146-840 gigatonnes of carbon dioxide (Gt CO_2) depending on the varying degrees of dissolved phase and separate-phase pore volume storage. Additional geological information and characterization of these basins, including detailed, formation-specific mapping will be required before their specific potential for CO_2 sequestration can be more accurately assessed.[94]

D. *Colorado's CCS Efforts*

Colorado had 11 coal mines in 2009; three were surface mines and eight were underground mines. Production was a little over 28 million tons, which is a little under 5% of the coal produced in the western states.[95] Colorado coal production decreased almost 9% between 2006 and 2009.[96] Colorado has 14 coal-fired power plants that have 33 units with a total capacity of 5,308 MWs.[97] Colorado has encouraged CCS and clean coal technologies, and in

84. *Id.* at 3-4.
85. *Id.* at 9.
86. *Id.* at 10-11.
87. *Id.* at 13-14.
88. *Id.*
89. *Id.* at 15.
90. *Id* at 16-18.
91. *See* Margot Roosevelt, *California Air Regulators Approve Carbon-Trading Plan*, L.A. Times, Dec. 17, 2010, http://www.latimes.com/news/local/la-me-1217-climate-cap-trade-20101217,0,562122.story (last visited Mar. 20, 2011).
92. California Geological Survey, An Overview of Geologic Carbon Sequestration Potential in California (Dec. 2006), *available* at http://www.consrv.ca.gov/CGS/News/CEC-500-2006-0882.pdf.
93. *Id.* at 1.
94. *Id.* at 55.
95. EIA Mine Type, *supra* note 1.
96. Source Watch, *Colorado and Coal*, http://www.sourcewatch.org/index.php?title=Colorado_and_coal#Existing_coal_plants (last visited Mar. 30, 2011).
97. Source Watch, *Category: Existing Coal Plants in Colorado,* http://www.sourcewatch.org/index.php?title=Category:Existing_coal_plants_in_Colorado (last visited Mar. 29, 2011). The plants are Arapahoe Station, Cameo Station (projected to be shut down by 2010), Cherokee Station, Clark Station, Comanche Generating Station, Craig Station, Hayden Station, Martin Drake Power Plant, Nucla Station, Pawnee Station, Rawhide Energy Station, Ray Nixon Power Plant, Trigen Colorado Steam Plant, Valmont Station (has proposed shutting down one unit), and Yampa Project. (Although

2009, a site near Craig, Colorado, was awarded a demonstration CCS project by the federal government.[98] However, recent actions by the Colorado Legislature reduce incentives for CCS by essentially requiring coal plants to be replaced with natural gas plants.[99] On April 19, 2010, H.B. 1365 was signed by the governor. It requires utilities to submit an emissions reduction plan that requires Xcel, the state's largest utility to reduce NO_2 emissions up to 80% from 900 MWs or 50% of the utility's generating capacity, whichever is less. This will necessitate converting coal-fired power plants to natural gas or other low-emission electricity sources.[100] Colorado also enacted legislation on March 22, 2010, to increase the percentage of renewable energy from investor-owned and certain other utilities from 20 to 30%.[101] These laws will reduce the need for CCS.

1. Research Support for Carbon Sequestration and IGCC Technology

The Colorado Legislature directed the Colorado Department of Public Health and Environment to administer the following research grants regarding CCS or IGCC technology.[102] The Colorado School of Mines was to receive $50,000 to conduct CCS research on geologic carbon sequestration.[103] The University of Colorado was "to conduct research on the emerging international and domestic markets in greenhouse gas emissions and to conduct research on private firms in various economic sectors that are reducing emissions of greenhouse gases."[104] As required by statute, the recipient institutions reported the results of their research to the Agriculture Committees of the Colorado House and Senate on March 15, 2007.[105] After synthesizing their findings, the report made numerous recommendations including the need to promote state policies to enable CCS in all potential sinks, including geological targets, and stimulate the growth of a new CCS industry in the state by providing incentives for companies with the appropriate skills to explore new business opportunities as well as research support.[106]

This report was accompanied by the Colorado Climate Action Plan (Action Plan), which outlined the Colorado global warming mitigation strategy.[107] The Action Plan recognizes CCS technology as a potential means to balance the economic benefit of Colorado's coal production with the need for cleaner, low-carbon fuels.[108] To ensure that geologic sequestration can begin along with the deployment of IGCC technologies, the Departments of Natural Resources and Public Health and the Environment will work to expeditiously resolve the hurdles to geologic sequestration, including identifying potential sequestration sites in Colorado and developing an appropriate regulatory framework.[109]

2. Clean Energy Development Authority

Colorado created a Clean Energy Development Authority (Authority) that is empowered to facilitate the production and consumption of clean energy; increase the transmission and use of clean energy by financing and refinancing projects located within or outside the state for the production, transportation, transmission, and storage of clean energy, including pipelines, and related supporting infrastructure and interests therein; and facilitate the efficient use of energy.[110] One of the Authority's mandates is to "convene qualified task forces to develop . . . official recommendations for the general assembly regarding the types of clean energy projects that the authority should finance, refinance, or otherwise support."[111] The Authority is mandated to convene a task force to assess whether IGCC facilities, or other clean coal technologies with the potential for substantial sequestration of carbon emissions, should be considered clean energy projects that the authority should support, and, if so, the nature and extent of any restrictions, including, but not limited to, specific CO_2 emissions sequestration requirements that such projects should satisfy as a prerequisite to authority support.[112]

In 2009, the Authority published a report on the infrastructure needed for renewable energy development—the REDI Report. The goal of the Report was to outline methods for Colorado to meet its goal of a 20% reduction in CO_2 emissions by 2020 (the 20/20 goal). (This goal has now been increased to 30% reductions as discussed above.) The REDI Report explored ways to reach the 20/20 goal,

this is 15 plants, it is the list provided by Source Watch, which lists the number of plants in Colorado as 14.)

98. *See* Tri-State, *Tri-State to Participate in $4.8 Million Carbon Sequestration Project*, http://www.tristategt.org/NewsCenter/NewsItems/Carbon-sequestration-project.cfm (last visited Mar. 30, 2011).
99. Colo. Rev. Stat. Ann. §40-3.2-204 (West 2010); *see also 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).
100. Tripp Baltz, *State Law Requires Utilities to Reduce Emissions From Coal-Fired Power Plants,* 41 Env't Rep. (BNA) 912 (Apr. 23, 2010).
101. Colo. Rev. Stat. Ann. §40-2-124(E) (2010 West); *see also Colorado Bill Increases Renewables Standard,* 41 Env't Rep. (BNA) 704 (Mar. 26, 2010).
102. Colo. Rev. Stat. Ann. §25-1-1303(1) (2006).
103. Colo. Rev. Stat. Ann. §25-1-1303(2)(b) (2006).
104. Colo. Rev. Stat. Ann. §25-1-1303(2)(c) (2009).
105. Colo. Rev. Stat. Ann. §25-1-1303(3) (2009).
106. Rich Conant et al., The Colorado Climate Change Markets Act: Report to the Colorado Legislature (Mar. 15, 2007), *available at* cees.colorado.edu/CCMA.pdf .
107. *See generally* Office of Governor Bill Ritter Jr., Colorado Climate Action Plan: A Strategy to Address Global Warming (2007), http://www.colorado.gov/cs/Satellite/GovRitter/GOVR/1251568200609 (last visited Mar. 29, 2011).
108. *Id.* at 18.
109. *Id.* at 19. A cursory search of the Colorado Climate Action Plan suggests there have been no official press releases, updates, or other actions regarding the plan since its release in 2007. However, significant action has been taken towards meeting Colorado's goal of emission reductions.
110. Colo. Rev. Stat. Ann. §40-9.7-102(2)(a)-(c) (2008).
111. Colo. Rev. Stat. Ann. §40-9.7-106(1)(c)(I) (2008). The authority shall convene the task forces as soon as the authority determines that it has received sufficient moneys from gifts, grants, donations, or project fees to adequately fund the activities of the task forces.
112. Colo. Rev. Stat. Ann. §40-9.7-106(1)(c)(I)(B) (2007). This provision excludes IGCC projects described in §40-2-123 (2)(b)(I) that are specifically defined as clean energy pursuant to §40-9.7-103(5)(g). These provisions speak to IGCC facilities under review for support from of the Colorado Utilities Commission as new energy alternatives (discussed below).

but with the caveat that "proposed actions must not interfere with electric system reliability and should minimize financial impacts on customers and utilities."[113] In modeling the most economically efficient pathways to meet the 20/20 goal, the REDI Report noted that there were not funds to include CCS in its models. The Report pointed out that

> [c]oal will likely will [sic.] have a continued, but perhaps diminishing, role as an important source of baseload power generation [in Colorado] . . . . Should Colorado decide to implement the 20x20 goal, it is unlikely that new coal-fired generation would be added to the energy mix unless the plants contain major advances in carbon capture and storage (CCS).[114]

Although the Report seemed to discount CCS as a methodology to reach Colorado's 20/20 goal, it did identify CCS as a potential "game changer" if the technology advanced to enable commercial application of CCS within the 2020 time frame.

> A number of emerging technologies and policy developments could change whatever path is selected to reach the 20x20 goal. We highlighted the following potential "game-changers": electrification of the transportation sector, the potential for Smart Grid, increasing emphasis on distributed generation, greater penetration of photovoltaics, *breakthroughs in carbon capture and storage technologies* [emphasis added], the potential impact of shale gas on the electricity sector, the potential for new transmission technologies, feed in tariffs, and a national renewable electricity standard. . . . More than $3 billion of ARRA [American Recovery and Reinvestment Act] funds are dedicated to the advancement of CCS technology. Successful commercialization of CCS holds promise to reduce CO_2. However, the pathway to success with CCS may take many years.[115]

Acting on a request from Gov. Bill Ritter, the Department of Natural Resources organized a CCS Task Force, which has been meeting monthly since March 2010.[116] The 13-member task force is made up of legislators, agency officials, and stakeholders, and is tasked to come up with legal and regulatory recommendations for the 2011 legislative session to promote successful geologic carbon sequestration in Colorado.[117] As of winter 2010, no report had yet been issued from the task force.

Thus, it appears that although Colorado has a significant interest in CCS, from both a development and application perspective, the most recent legislative actions and government focus are more supportive of renewable resources and phasing out coal. While Colorado would welcome a CCS breakthrough, it seems to be relying on the federal government to promote and fund such a breakthrough rather than focusing its own funding sources and legislative initiatives on developing CCS.[118] However, with the formation of the CCS task force, the potential for new IGCC facilities, and experimental CCS projects taking place in Colorado, significant technology advancements could give CCS a place in Colorado's energy future.

3. New Energy Technologies

The Colorado Legislature recently empowered Colorado's Utilities Commission to include CCS and related technology in their permitting of power producing facilities.[119] Under Colorado law, the Colorado Utilities Commission may "give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in its consideration of generation acquisitions for electric utilities."[120] The Commission shall "consider proposals by Colorado electric utilities to propose, fund, and construct IGCC [Integrated Gasification Combined Cycle] generation facilities to demonstrate the feasibility of this clean coal technology with the use of western coal and with carbon dioxide capture and sequestration."[121] "An IGCC facility may also use natural gas, in addition to gasified coal, as a fuel in the combustion turbine."[122]

To be considered by the Commission, potential IGCC facilities must demonstrate electricity-generating IGCC technology using Colorado or western coal; not exceed 350 MWs of nameplate capacity, unless a larger size is needed to take advantage of financial incentives or cost-sharing opportunities; demonstrate the capture and sequestration of a portion of the project's CO_2 emissions; include methods and procedures to monitor the fate of the CO_2 captured and sequestered from the facility; and be located in Colorado.[123]

A utility may submit an application for a certificate of public convenience and necessity[124] and cost recovery for one IGCC project.[125] This application must include the reasons why the utility should be exempt from the Com-

113. Clean Energy Development Authority, Renewable Energy Development Infrastructure: Connecting Colorado's Renewable Resources to the Markets in a Carbon-Constrained Electricity Sector 3 (2009), http://rechargecolorado.com/index.php/programs_overview/utilities_and_transmission/clean_energy_development_authority/ (last visited Mar. 30, 2011) [hereinafter REDI Report].
114. *Id.* at 21.
115. *Id.* at 31, 34.
116. *See State Task Force to Target Carbon Capture and Sequestration*, Colorado Energy News (Mar. 11, 2010), http://coloradoenergynews.com/2010/03/state-task-force-to-target-carbon-capture-sequestration/ (last visited Mar. 30, 2011).
117. Colo. Dep't of Nat'l Res., Homepage, http://www.dnr.state.co.us/ (last visited Mar. 30, 2011).
118. *See, e.g.*, M.J. Clark, *Freudenthal, Fellow Govs ask Obama to Support Clean Coal*, Wyoming Bus. Rep. (Feb. 23, 2009), http://www.wyomingbusinessreport.com/article.asp?id=98784 (last visited Mar. 30, 2011).
119. Colo. Rev. Stat. Ann. §40-2-123(1)(b) (2009).
120. Colo. Rev. Stat. Ann. §40-2-123(1)(a) (2009).
121. Colo. Rev. Stat. Ann. §40-2-123(2)(a) (West 2010).
122. Colo. Rev. Stat. Ann. §40-2-123(2)(b)(II) (West 2010).
123. Colo. Rev. Stat. Ann. §40-2-123(2)(b)(I)(A)-(E) (West 2010).
124. A certificate for public convenience and necessity is the exclusive agreement between the utility and Commission defining the rights and obligations of the parties. 64 Am. Jur. 2d *Public Utilities* §158 (2009).
125. Colo. Rev. Stat. Ann. §40-2-123(2)(c) (West 2010).

mission's competitive resource acquisition rules.[126] A utility must also include information about the proposed facility's economic and technical feasibility; near-term and future commercial development potential; projected efficiency; projected cost, incremental average rate impact, and form of rate recovery; and any other relevant information.[127] To address environmental concerns, an application must also provide information on the project's water savings, emission rates, and other environmental benefits; environmental and public safety impacts; the portion of the project's emissions captured and sequestered; and an analysis of the economic implications and feasibility of different levels of CCS.[128]

The Commission shall provide the public an opportunity to comment and hold an evidentiary hearing on a utility's application.[129] If the Commission determines the project is in the public's interest, it may grant a certificate for public convenience and necessity instead of requiring the project to follow its competitive resource acquisition rules.[130] If approved, the IGCC plant shall constitute an appropriate component of a utility's resource plan. If the Commission approves a project, a declaratory order for cost recovery[131] shall provide, inter alia, that utilities are entitled to fully recover from their retail customers through rate adjustments costs for planning, development, constructing, and operating the IGCC plant, net any federal or state funds the project receives.[132] Similarly, if an IGCC plant's wholesale market is regulated by the Federal Energy Regulatory Commission (FERC), the Commission "shall determine whether to assign a portion of the IGCC project's cost of service to be recovered from the public utility's wholesale customers."[133] "All revenues a public utility receives from its wholesale customers for the IGCC project's costs shall be credited as an offset to the IGCC project's costs charged to the public utility's retail customers."[134] Approved facilities are entitled to recover the full life-cycle capital and operating costs, "unless the Commission finds such costs to be imprudent after fully taking into account the technical and financial challenges and uncertainties associated with the project."[135] Like other power-generating facilities, IGCC plants may recover, through an adjustment clause, for power purchased during planned and unplanned power outages during[136] and after the initial startup and testing period.[137] "In structuring the adjustment clause, the utility's return on investment in an IGCC project from time to time shall be limited to the utility's most recent commission-approved return on investment in other utility generation facilities."[138]

IGCC plants are required to report on the cost and performance of the project once it is commercially operating.[139] The Commission shall then conduct an investigation and public hearing to determine if shutting down, decommissioning, or repowering the IGCC plant is in the public's best interest. The utility sponsoring the IGCC project is entitled to full recovery of costs incurred in a shutdown, repowering, or decommissioning of the project.[140]

The Colorado Legislature has included several provisions to make IGCC projects more attractive to public utilities. For example, to reduce costs to Colorado consumers "the department of public health and environment [sic], the governor's office of economic development [sic], and the governor's energy office [sic] may provide public utilities with reasonable assistance in seeking and obtaining financial and other support and sponsorship for a project" from the U.S. Congress, DOE, and other appropriate federal and state agencies and institutions.[141] A utility must submit a copy of its IGCC proposal to the appropriate agencies, and the Governor's Energy Office will oversee and distribute any applicable funds for studying or developing IGCC projects.[142] Utilities may also seek financial support from Colorado's Clean Energy Development Fund under §24-22-118 of the Colorado Revised Statutes.[143] Additionally, public utilities "may develop, construct, or own an IGCC facility through a special purpose entity or other affiliated partnership or corporation."[144]

In November 2007, the Public Service Company of Colorado (Xcel Energy) included plans for an IGCC facility in its Electric Resource Plan. Initial plans projected a start date in 2010, but Public Service Company of Colorado has not yet filed an application with the Public Utilities Commission, making the plant's projected completion in 2016 doubtful.[145] There is no mention of the Colorado IGCC plant in Xcel's annual reports since 2007. Nevertheless, the REDI Report bases its CO_2 emissions projections on the assumption that an IGCC plant will be operational in Colorado by 2020.[146]

126. *Id.* Colorado's competitive resource acquisitions are found at 4 C.C.R. §723-3610 et seq. (2008).
127. Colo. Rev. Stat. Ann. §40-2-123(2)(c)(I)-(IV) (West 2010).
128. Colo. Rev. Stat. Ann. §40-2-123(2)(d)(I)-(IV) (West 2010).
129. Colo. Rev. Stat. Ann. §40-2-123(2)(e)(I) (West 2010).
130. *Id.*
131. Colo. Rev. Stat. Ann. §40-2-123(2)(e)(I) (West 2010).
132. Colo. Rev. Stat. Ann. §40-2-123(2)(f)(I) (West 2010). Provision includes additional cost recovery options and limitations.
133. Colo. Rev. Stat. Ann. §40-2-123(2)(f)(II) (West 2010). *See also* Colo. Rev. Stat. Ann. §40-2-123(2)(f)(III), (IV) (West 2010) (additional cost recovery from FERC-regulated entities).
134. Colo. Rev. Stat. Ann. §40-2-123(2)(f)(V) (West 2010).
135. Colo. Rev. Stat. Ann. §40-2-123(2)(g) (West 2010).
136. *Id.*
137. Colo. Rev. Stat. Ann. §40-2-123(2(h) (West 2010).
138. Colo. Rev. Stat. Ann. §40-2-123(2)(g) (West 2010).
139. Colo. Rev. Stat. Ann. §40-2-123(2(h) (West 2010).
140. *Id.*
141. Colo. Rev. Stat. Ann. §40-2-123(2)(j) (West 2010).
142. *Id. See also* Colo. Rev. Stat. Ann. §24-38.5-102(n) (West 2010) (Governor's Energy Office shall "[p]rovide public utilities with reasonable assistance, if requested, in seeking and obtaining support and sponsorship for an IGCC project as defined in 40-2-123(2)(b)(I), C.R.S., and manage and distribute to the utility some or all of any funds provided by the state or by the United States government to the state for purposes of study or development of an IGCC project as specified in section 40-2-123(2)(j), C.R.S.").
143. Colo. Rev. Stat. Ann. §40-2-123(2)(k) (West 2010).
144. Colo. Rev. Stat. Ann. §40-2-123(2)(l) (West 2010).
145. *See* REDI Report, *supra* note 113, at 21.
146. *Id.* at 10, 21.

E. Idaho's CCS Efforts

Idaho is not a coal-producing state,[147] and it has no coal-fired power plants,[148] although it obtains 42% of its base load power from coal-fired generators located in other states.[149] Idaho has worked to prevent coal-burning power plants from being sited in the state. The state Department of Environmental Quality opted not to participate in EPA's cap-and-trade program for mercury emissions in order to prevent new coal-fired power plants from seeking to locate in Idaho.[150] In 2002, the Idaho Legislature created a Carbon Sequestration Advisory Committee to work to develop a program to encourage biologic sequestration.[151] However, the state does not appear to have enacted any legislation dealing with geologic sequestration.

In February 2009, Idaho's Department of Environmental Quality (IDEQ) issued an air permit for a project being developed by Southeast Idaho Energy, LLC, that is designed to gasify 2,000 to 2,300 tons of coal and pet-coke per day to produce synthesis gas in order to produce ammonia, which will be used to produce nitrogen-based fertilizer. The permit did not include any limit on CO_2 emissions. The Sierra Club and the Idaho Conservation League sued to force the company to control CO_2. A settlement was reached that requires the plant to capture and sequester 58% of the plant's CO_2 emissions, which will reduce the emissions to levels found in natural gas-fired fertilizer plants. The IDEQ modified the air permit to incorporate the negotiated CO_2 limits while denying its applicability to other facilities, because CO_2 is not considered to be an air pollutant under Idaho law. The project is projected to require four years for completion, and, if successful, the requirements imposed by the settlement could become best available control technology (BACT) for other new or modified facilities.[152] Recent EPA guidance has indicated that CCS could be considered BACT on a case-by-case basis, if it can pass the necessary analysis to show it is a feasible option.[153] Rep. Mike Simpson (R-Idaho) has vowed to curtail EPA's reach, singling out EPA regulation of GHGs as an agency overreach. Representative Simpson chairs the Interior and Environment subcommittee of the House Appropriations Committee.[154]

147. EIA Mine Type, *supra* note 1.

148. U.S. DOE, *Electric Power and Renewable Energy in Idaho,* http://apps1.eere.energy.gov/states/electricity.cfm/state=ID (last visited Mar. 1, 2011).

149. Idaho Office of Energy Resources, *Baseload Power,* http://www.energy.idaho.gov/baseload.htm (last visited Mar. 1, 2011).

150. *See* Leslie Bradshaw, *Keep Idaho Out of Mercury Cap and Trade Plan,* Idaho Mountain Express, Jan. 19, 2007.

151. I.C. §§22-5201 to 22-5206.

152. Svend Brandt-Erichsen, Marten Law Group, *First State Air Permit With Enforceable CO_2 Limits Issued for Idaho Coal-Fueled Fertilizer Plant 2, available at* http://www.martenlaw.com/news/?20091214-permit-with-enforceable-co2-limits; *see also* Refined Energy Holdings, *Power County Advanced Energy Center*, http://www.rehinc.com/PCAEC.aspx (last visited Mar. 30, 2011).

153. *See* U.S. EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases* (Nov. 2010), http://www.epa.gov/nsr/ghgpermitting.html (last visited Mar. 30, 2011).

154. *See* U.S. Congressman Mike Simpson's website at http://simpson.house.go (last visited Mar. 31, 2011).

F. Kansas' CCS Efforts

In 2009, Kansas had one surface mine that produced 0.017% of the nation's coal. This was down from two surface mines in 2008.[155] However, according to available estimates, Kansas uses coal to produce about 71% of the electricity generated in the state. Kansas has 16 coal-fired power plants with a total capacity of 5,473 MWs and is 23rd in the nation in coal-fired electric-power production.[156]

The expansion of coal-burning power plant capacity has been very controversial in Kansas, spawning lawsuits, affecting political elections, and costing the state's top environmental protection employee his job.[157] The ramifications of the political and legal struggle played out when Sunflower Electric Power received approval of its permit to expand its operations with a new coal-fired power plant on December 10, 2010.[158] Because the permit was approved before January 2, 2011, Sunflower will not be subject to EPA's new monitoring requirements for GHGs. In order for this to occur, the public comment period was limited to 30 days. However, EPA warned the process must be fair:

> If [the department of] Kansas Health and Environment recommends that Sunflower be permitted before Jan. 2, EPA will review this initial decision by asking three important questions:
>
> First, does the Kansas permit include public-health protection standards required by sound science and federal law?
>
> Second, did Kansas operate all parts of its permitting process as required by the Clean Air Act?
>
> And finally, does a Sunflower permit satisfy public confidence in the impartiality and transparency of Kansas' system of safeguarding air quality?
>
> Kansas' air permitting law gives all three branches of state government important work, and also invites the people of the state to participate. That's why EPA must scrutinize not just the language of any Sunflower permit, but the whole state decision-making process that produced a permit.[159]

Sunflower claims it will capture and use some CO_2 emissions in an Integrated Bioenergy Center that grows algae, but it has no current geologic storage proposals.[160]

155. EIA Mine Type, *supra* note 1.

156. Source Watch, *Kansas and Coal*, http://www.sourcewatch.org/index.php?title=Kansas_and_coal (last visited Mar. 30, 2011).

157. *Id.*

158. Sunflower Electric Power Corp., *Sunflower Receives Air Permit for Holcomb Expansion Project, available at* http://www.sunflower.net/news/newsdetail.aspx?itemID=28 (last visited Mar. 31, 2011).

159. Karl Brooks, EPA Administrator, Region 7, *EPA Leader Pledges Fair Decision on Power Plant*, LJWorld.com, Nov. 27, 2010, http://www2.ljworld.com/news/2010/nov/27/epa-leader-pledges-fair-decision-power-plant/ (last visited Dec. 30, 2010).

160. *See* Sunflower Integrated Bioenergy, LLC, http://www.sunflowerbioenergy.com/ (last visited Mar. 3, 2011).

In 2007, Kansas enacted H.B. 2419 that directs the Kansas Corporation Commission to issue regulations for carbon sequestration and to create tax incentives to encourage carbon sequestration projects. This legislation, known as the Carbon Dioxide Reduction Act, was amended in 2010 by H.B. 2418.[161] The Act instructs the state Corporation Commission to develop rules governing the injection of CO_2 for either EOR or CCS.[162] In February 2010, the rules were approved and adopted into the Kansas Administrative Regulations.[163]

The Commission also has power to collect fees and impose any necessary requirements for monitoring, permitting, and inspection. The fees will go to a fund specifically for CO_2 injection and storage.[164] Companies who receive permits must provide annual proof to the Commission of sufficient finances to cover closure costs.[165] The Act disclaims liability for CO_2 storage and maintenance except through legitimate claims under the Kansas Tort Claims Act. Finally, the Act preserves emergency remediation powers for the Commission.[166] The Commission is also granted powers to enforce violations with fines of up to $10,000 per incident, provide hearings and administer orders subject to judicial review, and conduct inspections.[167]

In conjunction with the Carbon Dioxide Reduction Act, the Kansas Legislature also passed statutes to give property and income tax breaks for CCS. Kansas Statute 79-233 provides a five-year property tax exemption for "[a]ny carbon dioxide capture, sequestration or utilization property; and any electric generation unit which captures and sequesters all carbon dioxide and other emissions."[168] In order to qualify for the exemption, the property should include any of the following:

(1) any machinery and equipment used to capture carbon dioxide from industrial and other anthropogenic sources or to convert such carbon dioxide into one or more products;

(2) any carbon dioxide injection well, as defined in K.S.A. 55-1637, and amendments thereto; and

(3) any machinery and equipment used to recover carbon dioxide from sequestration.[169]

Kansas Statute 79-32256 provides a deduction of the amortizable costs of CCS equipment over 10 years, with CCS equipment defined similarly to the property definitions above.

Kansas has begun experimental CCS projects with funding from DOE through the Recovery Act. In 2010, the University of Kansas in Lawrence was awarded $5 million to study CCS and EOR site characterization in south-central Kansas. The University of Utah has also been awarded $2.6 million to capture, compress, and transport one million tons of CO_2 per year for deep saline sequestration research in Coffeyville, Kansas.[170]

G. Montana's CCS Efforts

Montana has five surface mines and one small underground coal mine.[171] Although Montana has the largest coal reserves in the United States, the coal is of poorer quality than nearby Wyoming, and no surface mine permits have been issued in Montana since 1988.[172] Four of the surface mines produced 98.3% of Montana's coal in 2006.[173] In 2009, Montana produced 39.49 million tons, which was a little less than 7% of western coal production.[174] About three-fourths of the coal mined is shipped to customers in other states and, increasingly, internationally.[175] In 2006, Montana was the sixth biggest producer of coal in the United States; however production has expanded only modestly since the mid-1980s and is expected to remain stable.[176] Expansion is limited due to the low quality of Montana coal, the distance from markets, the need for expensive transportation infrastructure expansion, and political opposition from agricultural interests.[177] The state had seven coal-fired generating stations in 2005 with 2,536 MWs of capacity, which made up 47.3% of the state's electric-generating capacity.[178] However, the vast majority—89.6% of Montana's coal-fired electric-generating capacity—is found at the four units that comprise the Colstrip Steam Plant (capacity 2,272 MWs), and that facility is responsible for more than one-half the state's CO_2 emissions.[179] Because of political opposition, expansion of coal-fired electric-generating capacity in Montana will be difficult. However, the state's governor, Brian Schweitzer, is an ardent advocate for clean coal, and CCS and has been called the "Coal Cowboy."[180] In 2007, Montana joined the Western Climate Initiative (WCI), but it has not passed the legislation needed to participate in the first phase of the cap-and-trade program that will begin in January 2012.[181]

In Montana, regulatory authority for well permits, including injection for EOR or storage, is exercised by the

161. K.S.A. 55-1637 (West 2010).
162. *Id.* at (b), (f), (g).
163. *See* K.A.R. 82-3-311a, 1100-1120.
164. *Id.* at (c)-(d).
165. *Id.* at (e).
166. *Id.* at (h)-(i).
167. K.S.A. 55-1639 through 1640 (West 2010).
168. K.S.A. 79-233(a) (West 2010).
169. K.S.A. 79-233(d) (West 2010).
170. U.S. DOE, *Kansas Recovery Act Snapshot*, http://energy.gov/recovery/ks.htm (last visited Mar. 15, 2011).
171. EIA Mine Type, *supra*, note 1.
172. Energy Watch Group, Coal: Resources and Future Production 37 (Mar. 2007), *available at* http://www.energywatchgroup.org/Startseite.14+M5d637b1e38d.0.html.
173. Source Watch, *Montana and Coal,* http://www.sourcewatch.org/index.php?title=Montana_and_coal#Active (last visited Mar. 6, 2011).
174. EIA Mine Type, *supra* note 1.
175. Source Watch, *Montana and Coal*, *supra* note 173.
176. *Id.*
177. *Id.*
178. *Id.*
179. *Id.*
180. *See* Lesley Stahl, *Montana's Coal Cowboy*, 60 Minutes (Feb. 26, 2006), http://www.cbsnews.com/stories/2006/02/24/60minutes/main1343604.shtml (last visited Mar. 6, 2011).
181. *See* Dustin Till, Marten Law Group, *Picking Up the Pieces—Western Climate Initiative Releases Cap-and-Trade Program Design* (Aug. 20, 2010), *available at* http://www.martenlaw.com/newsletter/20100820-cap-and-trade-design-released.

Montana Board of Oil and Gas.[182] Montana has a state NEPA-equivalent process administered by the Department of Environmental Quality.[183] The environmental requirements place special emphasis on protection of private property rights.[184] The state NEPA process is applicable to development on state and private lands. In 2009, Montana passed legislation encouraging and regulating CCS.[185]

The Act Regulating Carbon Sequestration (Montana CCS Act) maintains the dominance of mineral rights, and allows mineral owners or lessees to drill and/or inject substances through or around sequestration sites, as long as the storage site's integrity is preserved. However, unless otherwise established by deed, pore space is presumed to belong to the surface owner.[186] A sequestration operator must pay the Board of Oil and Gas a fee for each ton of CO_2 injected. If the operator chooses to accept indefinite liability for the site, the fees may be refunded. However, if the Board determines that the operator *must* accept permanent liability because the site does not comply with regulatory requirements for safety and long-term structural integrity, the fees are retained by the Board until the site comes into compliance and liability may be transferred. The fees will be placed in an account for the Board to use for long-term site monitoring and liability.[187]

During the injection phase, operators must post a bond sufficient to cover projected liability. The site operator is liable for the operation and management of the injection well, the storage reservoir, and the actual liquids injected until a Certificate of Completion is issued.[188] The Certificate of Completion may be issued no earlier than 15 years after injection activities have been completed. The certificate may be issued only if the operator:

(A) is in full compliance with regulations governing the geologic storage reservoir;

(B) can show that the geologic storage reservoir will retain the CO_2 stored in it;

(C) shows that all wells, equipment, and facilities to be used in the post-closure period are in good condition and retain mechanical integrity;

(D) shows that it has plugged wells, removed equipment and facilities, and completed reclamation work as required by the board;

(E) shows that the CO_2 in the geologic storage reservoir has become stable, which means that it is essentially stationary or chemically combined or, if it is migrating or may migrate, that any migration will not cross the geologic storage reservoir boundary; and

(F) shows that the geologic storage operator will continue to provide adequate bond or other surety after receiving the certificate of completion for at least 15 years following issuance of the certificate of completion and that the operator continues to accept liability for the geologic storage reservoir and the stored CO_2.[189]

Before issuing the Certificate, the Oil and Gas Board must consult with the Department of Environmental Quality; however, the Oil and Gas Board has the final decision of whether to issue the Certificate. If the site complies with the above requirements for 15 years, the operator may transfer title to the storage reservoir and the CO_2 to the state if the operator can show that the reservoir and wells are in full compliance with the above requirements and that the reservoir will "maintain its structural integrity and will not allow carbon dioxide to move out of one stratum into another or pollute drinking water supplies."[190] The Board of Land Commissioners will make the final decision as to whether the state will take ownership of the title.

The Act provides a path for EOR wells to be converted to storage sites.[191] It also establishes that contamination of the water in a storage reservoir by CO_2 does not constitute pollution.[192] The Act also includes regulations for well spacing and unitization, discharge, permitting, and other administrative matters.

In addition to the Montana CCS Act, Montana has passed legislation giving tax breaks for CCS equipment used for capture, transportation, and sequestration; and granting common carrier status for CO_2 pipelines.[193] In 2007, Montana passed a statute that prohibits approval of new electric-generation facilities that are primarily fueled by coal unless the facility captures and sequesters at least 50% of the CO_2.[194] The prohibition is in place "[u]ntil the state or federal government has adopted uniformly applicable statewide standards for the capture and sequestration of carbon dioxide."[195]

As part of DOE's Big Sky Regional Carbon Sequestration Partnership, Montana State University has been studying the viability of a deep saline formation called the Kevin Dome in northern Montana. "Mapping suggests a viable reservoir for CO_2 sequestration at Kevin Dome in the Duperow Formation that has additional capacity not currently occupied by naturally occurring CO_2."[196]

182. Mont. Code Ann. §75-11-101 (West 2010).
183. Montana Environmental Policy Act (MEPA), Mont. Code Ann. §§75-1-101 through 75-1-1112 (West 2010).
184. Mont. Code Ann. §75-11-106 (West 2010).
185. An Act Regulating Carbon Sequestration, SB 498, 61st Leg. (Mont. 2009) [hereinafter Mont. SB 498].
186. Mont. SB 498 §1.
187. Mont. SB 498 §2.
188. Mont. SB 498 §3.
189. Mont. SB 498 §4.
190. Mont. SB 498 §4(7)(B)(I) & (II).
191. Mont. SB 498 §5.
192. Mont. SB 498 §8(25)(c).
193. *See* MCA §§15-6-158; 15-24-3102, 3111; 82-11-180 (West 2010)
194. Mont. Code Ann. §69-8-421(8) (West 2010).
195. *Id.*
196. NETL, *Big Sky Regional Carbon Sequestration Partnership—Validation Phase: Fact Sheet* 5 (July 2010), http://www.netl.doe.gov/technologies/carbon_seq/core_rd/RegionalPartnership/BIGSKY-VP.html (last visited Mar. 6, 2011).

H. Nebraska's CCS Efforts

There are no coal mines in Nebraska, but the state has 15 coal-fired electric-power plants with a capacity of 3,204 MWs, which is 42.8% of the state's total capacity.[197] Three of the power plants, Gerald Gentleman, Nebraska City, and North Omaha, account for 83.0% of the state's coal-fired power capacity and produce 45.6% of the state's CO_2.[198] Nebraska formed a State Carbon Sequestration Committee in 2000; however, this committee has focused almost exclusively on biological sequestration.[199] As of this time, Nebraska does not appear to have any legislation dealing with geologic CCS.

I. Nevada's CCS Efforts

Nevada has no coal production.[200] It has two coal-fired power plants. The North Vlamy Station has two units with a total of 522 MWs capacity.[201] The Reid Gardner Station has four units with a total of 612 MWs capacity.[202] The Mohave Generating Station (1,580 MWs) ceased operations on Dec. 31, 2005.[203] There do not appear to be any statutes in Nevada dealing with geologic carbon sequestration. Nevada is only an observer in the WCI, and thus has no plans to participate in the cap-and-trade program. However, Nevada has passed legislation for a renewable portfolio standard for electricity providers, requiring providers to generate, acquire, or save electricity from renewable sources as an increasing percentage of their total output—from 6% in 2005 to at least 25% in 2025, with at least 5% from solar energy.[204] Regulations implementing these standards make no mention of CCS or geologic sequestration.[205]

J. New Mexico's CCS Efforts

New Mexico has one underground coal mine and five surface mines that produced a total of 25.124 million tons of coal in 2009. This is about 4% of western coal output.[206] New Mexico has 11 coal-fired electric-generating units with a total capacity of 4,382 MWs.[207] Ten units at three locations exceed 50 MWs.[208] The Four Corners Steam generating plant is one of the largest in the country and has been the focus of considerable controversy and legal action over the past few decades. California Edison, a 48% owner, recently announced that it would sell its shares of the plant to Arizona Public Service. If the purchase is approved, Arizona Public Service plans to shut down units 1, 2, and 3 and install emissions control technology as required by EPA on units 4 and 5.[209]

On December 1, 2007, the New Mexico Oil Conservation Division published a report pursuant to a 2006 executive order dealing with geologic sequestration.[210] It was titled *A Blueprint for the Regulation of Geologic Sequestration of Carbon Dioxide in New Mexico*. The report identified numerous legal issues that needed to be addressed if New Mexico were to embrace carbon sequestration, including the most basic issue that New Mexico has no clear authority to regulate CO_2 injection for sequestration purposes. In the following year, Gov. Bill Richardson worked to reduce New Mexico's GHG emissions, but no specific requirements relating to carbon sequestration were imposed.[211]

The legislature did pass S.B. 994, which recognizes CCS as an "Eligible Generation Plant Cost" and provides tax incentives for CCS.[212] Tax credits are available to individuals, corporations, and service providers involved with a CCS project that:

> captures and sequesters or controls carbon dioxide emissions such that by the later of January 1, 2017, or eighteen months after the commercial operation date, no more than one thousand one hundred pounds per megawatt-hour of carbon dioxide is emitted into the atmosphere.[213]

A public utility that incurs costs in adopting CCS technology may also recover those costs.[214]

On November 2, 2010, regulations for the New Mexico cap-and-trade program under the WCI were finalized.[215] Although CCS is not an official policy of the New Mexico cap-and-trade program, CCS may be recognized for offset credit if an operation meets certain criteria.[216] New Mexico

197. Source Watch, *Nebraska and Coal*, http://www.sourcewatch.org/index.php?title=Nebraska_and_coal (last visited Mar. 7, 2011).
198. *Id.*
199. Neb. Dep't of Nat'l Res., *Carbon Sequestration, Greenhouse Gas Emissions, and Nebraska Agriculture—Background and Potential: A Report Relating to the Requirements of LB 957 of the 2000 Session of the Nebraska Unicameral and Containing the Recommendations of the Carbon Sequestration Advisory Committee* (Dec. 1, 2001).
200. EIA Mine Type, *supra* note 1.
201. Source Watch, *Existing Coal Plants in Nevada*, http://www.sourcewatch.org/index.php?title=Category:Existing_ coal_plants_in_Nevada (last visited Mar. 7, 2011).
202. Nev. Div. Envt'l Protection, *BART Determination Review of NV Energy's Reid Gardner Generating Station Units 1, 2, and 3*, 1 (Oct. 22, 2009).
203. Southern Cal. Edison, *Power Generation: Mohave Generation Station,* http:www.sce.com/powerandenvironment/powergeneration/mohavegenerationstation/ (last visited Mar. 7, 2011).
204. Nev. Rev. Stat. 704.7821 (West 2010).
205. *See* Nev. Admin. Code §§704.8831-704.8893 (West 2010).
206. EIA Mine Type, *supra* note 1.
207. Source Watch, *New Mexico and Coal*, http://www.sourcewatch.org/index.php?title=New_Mexico_and_coal#Existing_coal_plants (last visited Mar. 7, 2011).
208. *Id.* The plants are Four Corners (2,269 MWs), San Juan (1,848 MWs), and Escalante (257 MWs).
209. *See* Marjorie Childress, *Four Corners Power Plant to Reduce Emissions*, New Mexico Independent (Nov. 9, 2010).
210. N.M. Energy, Minerals, Nat'l Res. Dep't, Oil Conservation Div., A Blueprint for the Regulation of Geologic Sequestration of Carbon Dioxide in New Mexico (Dec. 1, 2007), *available at* http://www.emnrd.state.nm.us/ocd/documents/CarbonSequestrationFINALREPORT1212007.pdf; *see also* N.M. Exec. Order No. 2006-69 (2006), http://www.governor.state.nm.us/2006orders.php (last visited Mar. 7, 2011).
211. *See* N.M. Env't Dep't, *Science of Climate Change and New Mexico Projections*, http://www.nmenv.state.nm.us/aqb/GHG/Science_Projections.html (last visited Mar. 7, 2011).
212. N.M. Stat. Ann. §§7-2-18.25; 7-2A-25; 7-9-114; 7-9G-2; 62-6-288 (West 2010).
213. N.M. Stat. Ann. §7-2-18.25(L)(2)(c) (West 2010).
214. N.M. Stat. Ann. §62-6-28(B) (West 2010).
215. N.M. Admin. Code §§20.2.350.1-20.2.350.399 (N.M. Reg. Dec. 1, 2010), *available at* http://www.nmcpr.state.nm.us/nmregister/xxi/xxi22/xxi22.pdf.
216. *See* N.M. Admin. Code §20.2.350.208(A)(1) (N.M. Reg. Dec. 1, 2010), *available at* http://www.nmcpr.state.nm.us/nmregister/xxi/xxi22/xxi22.pdf.

is the only state besides California that currently plans to participate in the first phase of the WCI cap-and-trade program that begins in January 2012. However, New Mexico voters elected a Republican governor in the November 2010 election who is opposed to cap and trade and is working to kill it.[217]

The DOE Southwest Partnership has been experimenting with CCS in the San Juan Basin of northwestern New Mexico. A pilot test recently concluded injecting 18,400 tons of CO_2 into a coal bed with high methane production, testing the viability of "enhanced coal-bed methane" production. Although this basin is relatively isolated, and thus CCS would have to take place locally, there are several power plants with significant CO_2 output in this region, making future CCS efforts there possible.[218]

K. *North Dakota's CCS Efforts*

North Dakota produces 2.79% of the nation's coal from four surface mines.[219] The state has 15 coal-fired electric-power plants with a total capacity of 4,246 MWs; seven plants have units larger than 50 MWs.[220] Basin Electric is partnering with Powerspan Corporation and Burns & McDonnell to demonstrate CO_2 removal from the emissions of a lignite-based boiler in Antelope Valley. DOE provided $100 million and the U.S. Department of Agriculture announced it was loaning up to $300 million for the project in January 2009. Basin Electric's subsidiary also runs the nearby Great Plains Synfuels Plant, which is powered by the Antelope Valley plant and captures about 3 million tons per year of CO_2 and transports it by pipeline to oil fields in Canada for EOR injection and potential permanent storage, making it part of the largest CCS operation in the world.[221]

Perhaps because it is home to successful CCS operations, North Dakota has enacted comprehensive legislation to promote and regulate CCS. In 2009, S.B. 2095 was passed, setting forth priorities and regulations for geologic storage of CO_2.[222] The Act declares that North Dakota will promote CCS as in the public interest for both environmental and economic reasons. The Industrial Commission is given authority over all CCS activities, including permitting, enforcement, financial oversight, and field boundaries.[223] The Commission also has authority to require pore space to be used for storage, even if owners of the pore space have refused their permission.[224] Stored CO_2 will not be considered a pollutant or a nuisance.[225] Other property interests will not be harmed by CO_2 storage, and mineral owners may drill through or around the storage space if they comply with Commission guidelines.[226] A trust fund is developed with fees from storage permits. This fund will allow the Commission to assume long-term liability and responsibility for storage reservoirs.[227] Similar to Montana, North Dakota assigns liability to the operator while injection is underway and until a Certificate of Completion is issued by the Commission.[228] The Certificate can be issued 10 years after injections have ceased and after the Commission has held public hearings and consulted with the state Department of Health.[229] Once the Certificate has issued, the CCS operator may transfer liability and ownership of the reservoir to the state of North Dakota.[230] The legislation also distinguishes CO_2 injection for EOR from geologic storage. EOR injection is regulated under oil and gas regulations, unless it is later decided to convert an EOR injection site to a storage site.[231]

North Dakota also provides tax relief for EOR injection projects for the first five years.[232] CO_2 pipelines can be granted Common Carrier status, which includes eminent domain powers.[233] Finally, pore space is vested in the surface estate owner and may not be severed from the surface estate. Pore space may, however, be leased without a severance occurring. Mineral ownership remains the dominant interest as under the common law.[234]

North Dakota chose not to join the Midwest Regional Greenhouse Gas Reduction Accord. It did, however, adopt the Midwestern Energy Security and Climate Stewardship Platform, which includes the promotion of advanced coal technologies and CCS.[235]

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217. *Governors' Turnover Could Spur Mixed Results for Environmental Policy,* XXI Clean Air Rep. (Inside EPA) 23:16 (Nov. 11, 2010); Bonner R. Cohen, *Governor Martinez Likely to Kill New Mexico's Cap-and-Trade Scheme*, Enviroment & Climate News Jan. 2011, http://www.heartland.org/environmentandclimate-news.org/article/28884/Governor_Martinez_Likely_to_Kill_New_Mexicos_CapandTrade_Scheme.html (last visited Mar. 31, 2011); *but cf.* Marte Lightstone, *State of New Mexico Adopts Suite of Expansive Greenhouse Gas Emission Regulations*, Modrall Sperling (Feb. 3, 2011), http://www.modrall.com/0203111296730436.art; *Legislators Battled to Protect Environment During Session,* DailyLobo.com, http://www.dailylobo.com/index.php/article/2011/03/legislators_battled_to_protect_environment_during_session (last visited Apr. 5, 2011).
218. New Mexico Bureau of Geology and Mineral Resources, *Carbon Sequestration in the Context of Climate Change*, New Mexico Earth Matters (Summer 2010), http://www.southwestcarbonpartnership.org/ (last visited Mar. 7, 2011).
219. EIA Mine Type, *supra* note 1.
220. Source Watch, *North Dakota and Coal,* http://www.sourcewatch.org/index.php?title=North_Dakota_and_coal (last visited Mar. 7, 2011).
221. *Id.*; *see also* Basin Electric Power Coop., *Electricity*, http://www.basinelectric.com/Electricity/index.html (last visited Mar. 7, 2011).
222. N.D. SB 2095 (2009); codified at N.D. Cent. Code §§38-20-01 et seq. (West 2010).
223. N.D. Cent. Code §38-20-03 (West 2010).
224. N.D. Cent. Code §38-20-14 (West 2010).
225. N.D. Cent. Code §38-20-12(1) (West 2010).
226. N.D. Cent. Code §38-20-13 (West 2010).
227. N.D. Cent. Code §38-20-14, 15 (West 2010).
228. N.D. Cent. Code §38-20-16 (West 2010).
229. N.D. Cent. Code §38-20-17 (West 2010).
230. *Id.*
231. *See* N.D. Cent. Code §§38-20-19; 38-08-01 et seq. (West 2010).
232. N.D. Cent. Code §7-51.1-03(5) (West 2010).
233. N.D. Cent. Code §49-19-01 et seq. (West 2010).
234. N.D. SB 2139 (2009); codified at N.D. Cent. Code §47-31-01 through 08 (West 2010).
235. *See* Press Release by Gov. Jim Doyle, *Ten Midwestern Leaders Sign Greenhouse Gas Reduction Accord; Also Establish Regional Goals and Initiatives to Achieve Energy Security and Promote Renewable Energy* (Nov. 15, 2007), http://www.wisgov.state.wi.us/journal_media_detail.asp?locid=19&prid=3023 (last visited Mar. 7, 2011).

L. Oklahoma's CCS Efforts

Oklahoma has one underground coal mine and nine surface coal mines, which are the source of 0.09% of U.S. coal production (down from 0.2% in 2006).[236] The state has 15 coal-fired electric-power plants, with 5,720 MWs of capacity, which is 26.6% of the state's total generating capacity.[237] These plants release 35.0% of the state's CO_2 emissions.[238]

In 2008, the Oklahoma Legislature created the Oklahoma Geologic Storage of Carbon Dioxide task force to prepare recommendations for the legislature on CCS by December 2008.[239] In 2009, the Oklahoma Legislature approved S. 610, which established a new section of law codified at Oklahoma Statutes, Title 27A, §3-5-101 et seq., known as the Oklahoma Carbon Capture and Geologic Sequestration Act.[240] The Act gives the Corporation Commission and the Department of Environmental Quality responsibility for implementing the Act with the division of responsibilities determined by the type of reservoir used for sequestration. The Corporation Commission is responsible for oil and gas reservoirs as well as coal-bed methane and mineral brine reservoirs. The Department of Environmental Quality is responsible for all other reservoirs, which would include deep-saline formations, unmineable coal seams where methane is not produced, basalt reservoirs, salt domes, and nonmineral-bearing shales.[241] The appropriate state regulatory agency will promulgate rules to administer and enforce the Act. The law provides for the agency to make a determination that a storage facility is suitable and feasible and that it will not contaminate "fresh water or oil, gas, coal, or other commercial mineral deposits" and will not "unduly endanger human health and the environment."[242] The overseeing agency is also empowered to carry out all duties connected with EPA's rules for the Underground Injection Control Program under the Safe Drinking Water Act.[243] The law extends the power of eminent domain to operators of storage facilities.[244] It creates a Carbon Dioxide Storage Facility Trust Fund to hold the proceeds of fees imposed on each ton of CO_2 injected for storage that will be used to fund the costs of long-term care of the facility.[245] The long-term monitoring and care of the facility will be the responsibility of the relevant state regulatory authority.[246] The Oklahoma Geologic Storage of Carbon Dioxide task force has been renewed and ordered to continue study of geological storage issues to facilitate CCS development in Oklahoma.[247]

In 2001, the Oklahoma Conservation Commission was ordered to prepare a report assessing past and future opportunities for carbon sequestration in Oklahoma, both biological and geological.[248] As a consequence of this study, the Conservation Commission now offers one of the only state-operated certification programs for validating CCS as an offset in connection with EOR operations.[249] Permanent rules for this program went into effect in 2009.[250]

In 2007, American Electric Power announced a commercial-scale CCS project using CO_2 captured from the Northeastern coal-fired plant in Oklahoma. The capture project at Northeastern would be one of the first commercial-scale captures of CO_2 at an existing coal-fired plant and would use a chilled ammonium process.[251] Commercial operations were projected to begin in 2011, but it now appears the date has been pushed back.[252]

M. Oregon's CCS Efforts

Oregon has no coal production.[253] The state has only two coal-fired power plants. The Portland General Electric Company (PGE) has asked Oregon regulators to approve a plan where it would discontinue the use of coal at its 601-MW Boardman plant, in eastern Oregon, by 2020 in exchange for some leeway on required technology upgrades.[254] To continue operating until 2020, PGE would spend an estimated $190 million on NO_x controls; under the compromise, PGE would still be required to spend $41 million to control SO_2 and mercury emissions in 2011 and 2012.[255] Oregon does not appear to have any governmental activity concerning geologic carbon sequestration, although it has passed statutes encouraging biological sequestration.[256]

Although Oregon appears to be moving away from coal-based energy generation, recent proposals to expand U.S. coal exports to Asia are based on using northwestern ports in Oregon and Washington as coal-exporting hubs. Environmentalists have vowed to oppose expansion of the ports to export coal.[257]

236. EIA Mine Type, *supra* note 1.
237. Source Watch, *Oklahoma and Coal*, http://www.sourcewatch.org/index.php?title=Oklahoma_and_coal (last visited Mar. 8, 2011).
238. *Id.*
239. Okla. SB 1765 (2008).
240. Okla. Stat. Ann., tit. 27A, §§3-5-101 through 106 (West 2010).
241. Okla. Stat. Ann., tit. §3-5-103 (West 2010).
242. Okla. Stat. Ann., tit. 27A, §§3-5-101 through 106 (West 2010).
243. Okla. Stat. Ann., tit. 27A, §3-5-104 (West 2010).
244. *Id.*
245. Okla. Stat. Ann., tit. 27A, §3-5-106 (West 2010).
246. *Id.* at §§3-5-107 & 108.
247. Okla. SB 1326 (2010).
248. Okla. Stat. Ann., tit. 27A, §3-4-103 (West 2010).
249. Oklahoma Conservation Commission, *Carbon Sequestration Certification Program*, http://www.ok.gov/conservation/Agency_Divisions/Water_Quality_Division/WQ_Carbon_Sequestration/Geologic_Sequestration_/ (last visited Mar. 8, 2011); *see also* Okla. Stat. Ann., tit. 27A, §3-4-103(B) (West 2010).
250. *See* Okla. Admin. Code §155:30-1-1 through 30-13-2 (2009).
251. *See* American Electric Power, *Press Release* (Oct. 16, 2007), http://www.aep.com/newsroom/newsreleases/?id=1412 (last visited Mar. 8, 2011).
252. PowerGen, *Carbon Capture R&D Gets $8 Billion Boost* (Apr. 1, 2009), http://www.powergenworldwide.com/index/display/articledisplay/358958/articles/power-engineering/volume-113/issue-4/departments/startup/carbon-capture-rampd-gets-8-billion-boost.html (last visited Mar. 8, 2011).
253. EIA Mine Type, *supra* note 1.
254. Tom Alkire, *Northwest's Only Coal-Fired Power Plants May Halt Use of Coal by 2025, Switch Fuels,* 41 Env't Rep. (BNA) 992 (May 7, 2010).
255. *Id.*
256. *See, e.g.*, Oreg. Rev. Stat. Ann. §§468A.250.1(h) & (i); 468A.290.2(a); 568.550.r(H).
257. *See, e.g.,* Scott Learn, *Mining Companies Aim to Export Coal to China Through Northwest Ports*, The Oregonian (Sept. 8, 2010), *available at* http://www.oregonlive.com/environment/index.ssf/2010/09/global_mining_companies_are_fo.html (last visited Mar. 8, 2011).

N. South Dakota's CCS Efforts

South Dakota has no coal production.[258] It has two coal-fired electric-generating plants with 481 MWs of capacity. One facility, the Big Stone plant, is responsible for 30.7% of the state's CO_2 emissions.[259] South Dakota has enacted legislation defining CO_2 as one of the fluids that subjects a pipeline to regulation as a transmission facility by the South Dakota Public Utilities Commission.[260] The CO_2 must be at least 90% CO_2 molecules compressed into a super-critical state.[261] A pipeline must obtain a permit from the Public Utilities Commission, and needs legislative approval for a trans-state line.[262] Approval from the legislature includes the power of eminent domain.[263] Other than this legislation, South Dakota does not appear to have legislation dealing with CCS or the related issues of pore-space ownership, liability, etc.[264] South Dakota has observer status in the Midwestern Greenhouse Gas Reduction Accord.

O. Texas' CCS Efforts

Texas has 12 surface mines that produce 3.26% of U.S. coal.[265] Texas is the third-ranked state for electricity produced from coal, which helps make the state the nation's highest emitter of CO_2. Coal is used to produce 36.5% of the electricity generated in Texas.[266] There are 40 coal-fired generators at 20 locations in Texas. They have a combined capacity of 21,240 MWs; 39 of the units exceed 50 MWs.[267]

Texas is a state where environmental groups have actively worked to prevent expansion of coal-fired electric-power facilities.[268] Luminant (formerly TXU), for example, in 2007, agreed to cancel eight of its 11 planned coal-fired power plants in return for environmental organizations agreeing not to oppose three new coal-fired power plants.[269] The company also agreed to expand wind generation and invest $400 million in energy-efficiency measures.[270] In another challenge, environmentalists agreed to drop challenges to a new 303-MW facility in return for numerous concessions by NuCoastal Power, including an agreement to invest in CCS if the technology becomes available.[271]

The Summit Power Group is developing a CCS facility called the Texas Clean Energy Project (TCEP). It will use CCS pre-combustion technology to capture 90% of the CO_2 emissions from a 400-MW IGCC coal-fired plant in west Texas. It will use the same CCS technology as planned for the FutureGen project in Mattoon, Illinois. The captured CO_2 will be injected into an oil field.[272] On December 4, 2009, DOE awarded TCEP $350 million to help develop the facility. It will begin construction in the fall of 2011 and begin sequestering carbon in 2014.[273] DOE has also awarded $154 million to NRG Energy, Inc. of New Jersey to build a 60-MW post-combustion CCS project in Thompsons, Texas. The project is meant to demonstrate the possibility of CCS for existing coal-powered units. The CO_2 will be used for EOR in nearby oil fields.[274]

Texas promotes a diverse energy portfolio and claims to have the most experience implementing and regulating EOR. In recent years, the legislature has enacted legislation regulating and encouraging CCS while the Texas governor publicly denounces federal regulation of the energy sector and state regulators have battled EPA regulation of CO_2 injection for EOR.[275] A full coverage of the Texas legislation is beyond the scope of this Article. Instead, highlights from some of the major bills are summarized.

1. Texas S.B. 1387

Texas S.B. 1387 became law in September 2009. S.B. 1387 defines anthropogenic CO_2 and assigns the Texas Railroad Commission as the regulatory agency for CO_2 storage or injection. Anthropogenic CO_2 includes any incidental substances that might be added to the CO_2 during extraction or injection processes.[276] Injection of CO_2 for storage purposes is distinguished from injection for EOR.[277]

The Railroad Commission will issue permits for CO_2 storage sites and may impose fees that will be placed in an Anthropogenic CO_2 Trust Fund, which can be used to cover permitting, monitoring, inspecting, and enforcing costs.[278] The executive director of the storage operation must provide a letter assuring that the operation "will not injure any freshwater strata in that area and that the formation or stratum to be used for the geologic storage facil-

258. EIA Mine Type, *supra* note 1.
259. Source Watch, *South Dakota and Coal*, http://www.sourcewatch.org/index.php?title=South_Dakota_and_coal (last visited Mar. 8, 2011).
260. S.D. Codified Laws §§49-41B-2 and 49-41B-2.1(2) (West 2010).
261. S.D. Codified Laws §49-41B-2(3) (West 2010).
262. S.D. Codified Laws §§49-41B-4; 49-41B-4.1 & 2 (West 2010).
263. S.D. Codified Laws §21-35-1.1 (West 2010).
264. *But see* Blayne N. Grave, *Carbon Capture and Storage in South Dakota: The Need for a Clear Designation of Pore Space Ownership*, 55 S.D. L. Rev. 72 (2010) (calling for legislation to regulate pore-space ownership).
265. EIA Mine Type, *supra* note 1.
266. Source Watch, *Texas and Coal*, http://www.sourcewatch.org/index.php?title=Texas_and_coal (last visited Mar. 9, 2011).
267. *Id.*
268. *See The Debate Over Coal Plants in Texas*, The Dallas Morning News, Apr. 2, 2007, http://www.dallasnews.com/sharedcontent/dws/news/longterm/stories/buscoalresources.162b5ce1.html (last visited Mar. 9, 2011).
269. *See How Environmentalists Shaped TXU Deal*, NPR, Feb. 27, 2007, http://www.npr.org/templates/story/story.php?storyId=7615616 (last visited Mar. 9, 2011).
270. *Kansas Pact May Set New Floor for Resolving Coal Plant Disputes,* XVIII Clean Air Rep. (Inside EPA) 7 (Apr. 7, 2007).
271. Source Watch, *Texas and Coal*, *supra* note 266.
272. *Id.*
273. Texas Clean Energy Project, *The Texas Clean Energy Project: A "NowGen" Carbon Capture Facility*, http://texascleanenergyproject.com/ (last visited Mar. 9, 2011); U.S. DOE, *Recovery Act: Clean Coal Power Initiative Round III*, http://fossil.energy.gov/recovery/projects/ccpi.html (last visited Mar. 9, 2011) [hereinafter DOE, *Recovery Act*].
274. DOE Recovery Act, *supra* note 273.
275. *See, e.g.*, Ramit Plushnick-Masti, *Driller Denies That It Contaminated Texas Aquifer*, Chron, Dec. 8, 2010, http://www.chron.com/disp/story.mpl/ap/tx/7328990.html (last visited Mar. 9, 2011); Gov. Rick Perry Press Release, *Gov. Perry: The Biggest Challenge to the Energy Industry Is Federal Overregulation* (July 28, 2010), http://governor.state.tx.us/news/press-release/14940/ (last visited Mar. 9, 2011).
276. Tex. Water Code Ann. §27.002(19) (Vernon 2009).
277. Tex. Water Code Ann. §27.042 (Vernon 2009).
278. Tex. Water Code Ann. §§27.043 through .045 (Vernon 2009).

ity is not freshwater sand."[279] The Railroad Commission must also assure that specific safety and financial conditions are met before issuing a CO_2 storage permit, including that the well may not impair existing rights, including mineral rights.[280]

The Texas legislation differs from some other states by making the use of CO_2 for storage or for EOR equivalent. "A conversion of an anthropogenic carbon dioxide injection well from use for enhanced recovery operations to use for geologic storage is not considered to be a change in the purpose of the well."[281] Although a potential storage site that has received CO_2 injection for EOR must be converted to an official and permitted storage site in order to qualify for title transfer to the state, this section blurs the line between injecting CO_2 for EOR, which has been regulated by the Railroad Commission and does not require a specific permit, and injecting CO_2 for permanent storage, which subjects the operations to the requirements described in this legislation. The rules outlining CO_2 ownership also specifically exempt CO_2 used in EOR.[282] Stored CO_2 is the property of the storage operator or the storage operator's heirs, successors, or assigns.

S.B. 1386 creates a trust fund for CCS, and it also provides for extraction of stored CO_2 for commercial or industrial uses.[283] The legislation also requires a report on site-identification and state land-leasing issues from the Commissioner of the General Land Office in coordination with the Bureau of Economic Geology of the University of Texas at Austin, the Railroad Commission of Texas, the Texas Commission on Environmental Quality, and the heads of other appropriate agencies by December 1, 2010.[284] A separate report is also required from the Texas Commission on Environmental Quality and the Railroad Commission of Texas, in consultation with the Bureau of Economic Geology of the University of Texas at Austin. This report is also due December 1, 2010, and should cover issues related to both EOR and non-EOR injection of CO_2 as well as agency jurisdictional issues, including federal jurisdiction, for CO_2 injection.[285] On December 2, 2010, the Texas Railroad Commission (the agency responsible for regulating resource extraction in Texas) approved new rules regulating CCS, as required by §11 of S.B. 1387.[286]

2. Texas H.B. 1796: Offshore Geologic Storage of CO_2

Texas H.B. 1796, effective September 1, 2009, empowers the Texas Natural Resource Conservation Commission (TNRC) to establish an offshore CO_2 repository to be located on offshore state lands.[287] The repository will be managed by the School Land Board, which may charge fees and establish carbon credits. The School Land Board will also acquire title to any CO_2 stored in the repository.[288] When the Board acquires title, it shall also assume liability; however, the producer of the CO_2 remains liable for any act or omission regarding the CO_2 before it was stored.[289]

H.B. 1796 also establishes Advanced Clean Energy Projects, which include coal-powered electric-generating plants that capture and store at least 50% of emissions. Such generation plant could qualify for the Advanced Clean Energy Project grant and loan program.[290] Section 30 of H.B. 1796 emphasizes Texas' commitment to developing CCS:

> The purpose of the changes in law made by this Act is to encourage the development of onshore and offshore geologic storage of carbon dioxide including by encouraging the development of advanced clean energy projects that capture carbon dioxide and sequester not less than 50 percent of the captured carbon dioxide in onshore or offshore geologic repositories. Securing the necessary capacity for geologic sequestration is essential to the success of carbon capture strategies, such as the advanced clean energy projects facilitated by the changes in law made by this Act. The success of the offshore repositories facilitated by this Act depends on an adequate supply of anthropogenic carbon dioxide, which is not currently being captured at industrial facilities in this state. The advanced clean energy grants established in this Act are intended to create the supply of anthropogenic carbon dioxide necessary to the success of the offshore repositories facilitated by this Act.[291]

3. Texas H.B. 469

H.B. 469 offers tax incentives for CCS activities. A franchise tax credit of $100 million or 10% of the total cost of a project is available to entities that qualify as Clean Energy Projects. To qualify for the credit, a CCS project would have to involve construction of a new facility and sequester at least 70% of emissions from electricity generation. The credit is only available in 2013.[292] The Clean Energy Project definition is modified with the following additional text:

> . . . whether the project is implemented in connection with the construction of a new facility or in connection with the modification of an existing facility and whether the project involves the entire emissions stream from the facility or only a portion of the emissions stream from the facility.[293]

279. Tex. Water Code Ann. §27.046 (Vernon 2009).
280. Tex. Water Code Ann. §27.051(a) (Vernon 2009).
281. Tex. Nat. Res. Code Ann. §91.802(c) (Vernon 2009).
282. Tex. Nat. Res. Code Ann. §120.002(a) (Vernon 2009).
283. Tex. Nat. Res. Code Ann. §§120.003 & .004 (Vernon 2009).
284. Tex. SB 1387, §9 (2009).
285. Tex. SB 1387, §10 (2009).
286. *See* 35 Tex. Reg. 9177 (Oct. 15, 2010); 16 Tex. Admin. Code §§5.101, 5.102, 5.201, 5.202, 5.203, 5.204, 5.205, 5.206, 5.207, 5.208 (Vernon 2010).
287. Tex. Health & Safety Code Ann. §382.503 (Vernon 2009).
288. Tex. Health & Safety Code Ann. §§382.505 & 507 (Vernon 2009).
289. Tex. Health & Safety Code Ann. §382.508 (Vernon 2009).
290. Tex. Gov't Code Ann. §447.013 (Vernon 2009); Tex. Health & Safety Code Ann. §391.002 (Vernon 2009).
291. Texas H.B. 1796, §30 (Sept. 1, 2009).
292. Tex. Gov't Code Ann. §490.352 (Vernon 2009).
293. Tex. Health & Safety Code Ann. §382.003(1-a)(A) (Vernon 2009).

A Clean Energy Project is further modified to require a pre-combustion facility to capture at least 70% of emitted CO_2. It also requires that captured CO_2 is capable of being both permanently sequestered for 1,000 years with 99% retention and supplied for EOR purposes.[294] The Railroad Commission is given authority to certify Clean Energy Projects, but only three projects may be certified. A Clean Energy Project applicant must contract with the Bureau of Economic Geology of the University of Texas at Austin for monitoring, measuring, and verification of the project.[295]

Section 4 of the legislation provides a sales tax exemption for personal property used in connection with a Clean Energy Project to capture, transport, inject, or prepare CO_2 for injection within the state.[296] A 50% reduction in the recovered oil tax rate is also provided for EOR operations that use CO_2 captured in Texas.[297]

In 2009, S.B. 126 and its companion H.B. 4384 would have placed a two-year moratorium on coal-fired power plants that are proposed without CCS capabilities. The bills were referred to committee, but did not pass during the 2009 session.[298]

Texas has developed significant legislation on CCS over the past several years, and although it is not a state that has promoted either federal or regional regulation of GHGs or action to prevent climate change, it has declared itself a leader in carbon regulation and storage, because of its decades of experience with EOR and global leadership in energy development.[299] At least one private industry group is monitoring and promoting Texas' efforts to support market-based CCS.[300] Texas is the last state that claims it is not ready or willing to implement EPA GHG permitting requirements.[301] Texas has indicated that it cannot or will not impose GHG permits in 2011 as required, because they are prohibited by law from doing so.[302]

P. Utah's CCS Efforts

Utah's is the nation's 13th largest coal producer, slipping a notch from 2006.[303] The state has eight underground coal mines.[304] There are six coal-burning electric utility plants in the state with 11 generating units, producing over 9,350 MWs.[305]

1. Utah's Procurement Act Carbon Sequestration Framework (S.B. 202)

Section 701 of the Utah Energy Resources Procurement Act (Procurement Act), provides a framework for carbon sequestration in the state.[306] Section 701 provides:

> by January 1, 2011, the Division of Water Quality and the Division of Air Quality, on behalf of the Board of Water Quality and the Board of Air Quality, respectively, in collaboration with the commission and the Division of Oil, Gas, and Mining and the Utah Geological Survey, shall present recommended rules to the Legislature's Administrative Rules Review Committee for the following in connection with carbon capture and accompanying geological sequestration of captured carbon.[307]

These rules are to: (1) ensure adequate health and safety standards are met; (2) minimize risk of unacceptable leakage from the injection well and injection zone; and (3) provide adequate regulatory oversight and public information concerning carbon capture and geologic sequestration.[308]

The statute enumerates aspects of carbon sequestration that are to be included in the administrative rules: site characterization approval; geomechanical, geochemical, and hydrogeological simulation; risk assessment; mitigation and remediation protocols; issuance of permits for test, injection, and monitoring wells; specifications for the drilling, construction, and maintenance of wells; issues concerning ownership of subsurface rights and pore space; allowed composition of injected matter; testing, monitoring, measurement, and verification for the entirety of the carbon capture and geologic sequestration chain of operations, from the point of capture of the CO_2 to the sequestration site; closure and decommissioning procedure; short- and long-term liability and indemnification for sequestration sites; conversion of enhanced oil recovery operations to CO_2 geological sequestration sites; and other issues as identified.[309]

Once the listed departments and divisions have drafted rules to effectuate the mandates of §701, the entities shall report any needed statutory changes to the legislature's Administrative Rules Review Committee.[310] The statute requires these entities to submit a progress report on rule development to the Public Utilities and Technology and

294. Tex. Nat. Res. Code Ann. §§120.001(2)(C), (D), & (E); .001(4) (Vernon 2009).
295. Tex. Nat. Res. Code Ann. §§120.001 through .004 (Vernon 2009).
296. Tex. Tax Code Ann. §151.334 (Vernon 2009).
297. Tex. Tax Code Ann. §202.0545(a) and (d) (Vernon 2009).
298. *See* H.B. 4384 and SB 126 legislative history, http://www.capitol.state.tx.us/BillLookup/BillNumber.aspx (last visited Mar. 10, 2011).
299. *See* Gov. Rick Perry Press Release, *Gov. Perry Speaks at Clean Carbon Policy Summit* (Oct. 5, 2010), http://www.governor.state.tx.us/news/press-release/15240/ (last visited Mar. 10, 2011).
300. *See* Texas Carbon Capture and Storage Association, http://txccsa.org/ (last visited Mar. 10, 2011).
301. Steven D. Cook, *All States but Texas Ready to Implement Greenhouse Gas Permitting Requirements,* 41 Env't Rep. (BNA) 2450 (Nov. 5, 2010).
302. *See Wyoming Becomes Latest State to Rebuff EPA on Climate Regulations,* XXI Clean Air Rep. (Inside EPA) 21:11 (Oct. 14, 2010); *EPA Eyes Texas Permit Audit Revision Amid State Fear of Facility Closures,* XXI Clean Air Rep. (Inside EPA) 21:17 (Aug. 19, 2010).
303. Source Watch, *Utah and Coal,* http://www.sourcewatch.org/index.php?title=Utah_and_coal (last visited Mar. 10, 2011); EIA Mine Type, *supra* note 1.
304. EIA Mine Type, *supra* note 1.
305. Utah Geological Survey, *Electricity*, http://geology.utah.gov/emp/energydata/electricitydata.htm (last visited Mar. 10, 2011). The plants are Bonanza (499.5 MWs), Intermountain 1 (820 MWs) & 2 (820 MWs), Carbon 1 (75 MWs) & 2 (113.6 MWs), Hunter 1 (488.3 MWs) & 2 (488.3 MWs) & 3 (495.6 MWs), Huntington 1 (498 MWs) & 2 (498 MWs), and Sunnyside Cogeneration (58.1 MWs). Kennecott Utah Copper Company has a nonutility plant with four units rated at a total of 182 MWs.
306. Utah Code Ann. §54-17 101 et seq. (2005).
307. Utah Code Ann. §54-17-701(1) (2009).
308. Utah Code Ann. §54-17-701(6) (2009).
309. Utah Code Ann. §54-17-701(1)(a)-(m)(2009).
310. Utah Code Ann. §54-17-701(2) (2009).

Natural Resources, Agriculture, and Environment Interim Committees by July 1, 2009.[311]

Like other states, Utah distinguishes carbon storage from other uses, such as EOR. The carbon sequestration rules only apply to "the injection of carbon dioxide and other associated injectants in approved types of geological formations for the purpose of reducing emissions to the atmosphere through long-term geological sequestration as required by law or undertaken voluntarily or for subsequent beneficial reuse."[312] Carbon sequestration rules do not apply to the injection of fluids for Class II injection wells, as defined in 40 C.F.R. §144.6(b) for the purpose of EOR.[313]

In addition to establishing an administrative rule framework, the Procurement Act includes carbon sequestration in its general energy procurement provisions. For example, subsection 602 et seq. seeks to have 20% of Utah's adjusted electric utility sales come from "qualifying electric" or "renewable sources" by 2025.[314] This percentage is "computed based upon *adjusted* retail electric sales, which is the total annual number of kilowatt-hours of retail electric sales by an electrical corporation, reduced by "the amount of . . . kilowatt-hours attributable to electricity generated or purchased in that calendar year from qualifying . . . carbon sequestration generation."[315] In calculating the required percentage of non-carbon electric sales, a Utah electric entity may include the number of tons of sequestered carbon either sequestered or purchased by the entity.

Under the Procurement Act, qualifying carbon sequestration must come from a fossil-fueled facility within the Western Electricity Coordinating Council[316] that becomes operational or retrofitted after January 1, 2008, and "reduces carbon dioxide emissions into the atmosphere through permanent geological sequestration or through another verifiably permanent reduction in carbon dioxide emissions through the use of technology."[317] Kilowatt-hours eligible to be included in the adjusted electric retail sales equation are:

> kilowatt-hours supplied by a facility during the calendar year multiplied by the ratio of the amount of carbon dioxide captured from the facility and sequestered to the sum of the amount of carbon dioxide captured from the facility and sequestered plus the amount of carbon dioxide emitted from the facility during the same calendar year.[318]

Utah also enacted the Utah Municipal Utility Carbon Emission Reduction Act (Municipal Act), which is similar to the Procurement Act but focuses on municipal reductions in CO_2 emissions instead of reductions from electrical corporations. The Municipal Act mirrors the Procurement Act in its central provisions and inclusions of carbon sequestration.[319]

2. The Utah Carbon Capture and Geologic Sequestration Working Group

In addition to passing laws regarding carbon sequestration, Utah has also created a Carbon Capture and Geologic Sequestration Working Group (CCGS Workgroup) under the Utah Department of Environmental Quality.[320]

The CCGS Workgroup has two primary goals. First, the group is to aid the appropriate state departments and divisions with implementing the Procurement and Municipality Acts by helping draft relevant administrative rules. Additionally, the CCGS Workgroup must assure these rules comply with existing state statutes and administrative rules, as well as existing and proposed federal statutes and regulations.[321] When asked about the progress of the CCGS Workgroup's mandate to create a progress report on the draft administrative rules by July 2009, the Department of Environmental Quality provided a May 20, 2009 "Progress Report"[322] as a power-point presentation given to the Utah Legislature.[323] However, this Progress Report does not contain any substantive information regarding

311. Utah Code Ann. §54-17-701(3) (2009). As of December 10, 2010, the state of Utah's climate change website has not yet posted or provided information on this progress report.
312. Utah Code Ann. §54-17-701(4) (2009).
313. Utah Code Ann. §54-17-701(5) (2009).
314. Utah Code Ann. §54-17-602(1)(a) (West 2010).
315. Utah Code Ann. §54-17-601(1)(a) (2008).
316.

> The Western Electricity Coordinating Council (WECC) is the regional entity responsible for coordinating and promoting bulk electric system reliability in the Western Interconnection. In addition, WECC assures open and non-discriminatory transmission access among members, provides a forum for resolving transmission access disputes, and provides an environment for coordinating the operating and planning activities of its members as set forth in the WECC Bylaws.
>
> WECC is geographically the largest and most diverse of the eight Regional Entities that have Delegation Agreements with the North American Electric Reliability Corporation (NERC). WECC's service territory extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 Western states between. Due to the vastness and diverse characteristics of the region, WECC and its members face unique challenges in coordinating the day-to-day interconnected system operation and the long-range planning needed to provide reliable electric service across nearly 1.8 million square miles.

Western Electricity Coordinating Council, *About WECC* http://www.wecc.biz/About/Pages/default.aspx (last visited Mar. 10, 2011).

317. Utah Code Ann. §54-17-601(6) (West 2010).
318. Utah Code Ann. §54-17-601(2) (West 2010).
319. *See* Utah Code Ann. §10-19-201(West 2010) (setting a 20% goal for qualifying or renewable energy in municipal utility retail electric sales); Utah Code Ann. §10-19-102(1)(a) (West 2010) (including carbon sequestration in the adjusted retail sales rate); Utah Code Ann. §10-19-102(2) (defining how to calculate deductible kilowatt-hours from carbon sequestration); Utah Code Ann. §10-19-102(7) (defining qualifying carbon sequestration facilities).
320. *See generally* State of Utah, Climate Change, Carbon Capture and Geologic Sequestration Workgroup, http://www.climatechange.utah.gov/CCGS_WG.htm (last visited Mar. 10, 2011) [hereinafter CCGSW].
321. *Id.*
322. Utah Dept. of Envtl. Quality, Carbon Capture and Geologic Sequestration Administrative Rule Development: Progress Report, presented to the Natural Resources, Agriculture, and Environment Interim Committee (May 20, 2009) (on file with author) [hereinafter Progress Report].
323. E-mail from Rusty Lundberg, Manager, Energy and Sustainability Group, Utah Department of Environmental Quality (Oct. 2, 2009) (on file with author).

rules not included in the Procurement Act. The report makes the legislature aware of the CCGS Workgroup website and synthesizes some of the general carbon sequestration information available on the website.[324]

The second task of the CCGS Workgroup is to prepare comments for the federal "Proposed Rule for Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells."[325] The period for general comment closed on December 24, 2008, and in August 2009, EPA released its Notice of Data Available for the rule and requested more public comment.[326] In December 2010, EPA published the final UIC rule in the *Federal Register*.[327] The CCGS Workgroup website provides substantial background information and documents relating to climate change and carbon sequestration.[328]

The CCGS Workgroup

> consists of an over-arching Steering Committee; three Subcommittees (CO_2 Capture and Separation, CO_2 Compression and Transport, and CO_2 Injection Well) that will focus on developing rules for the three major aspects of CCGS; an Advisory Committee that provides technical support to the Steering Committee and the Subcommittees; and a Stakeholder Group that provides for public and stakeholder input during the rules development process.[329]

3. Other Carbon Sequestration Activities in Utah

Utah has joined DOE's Southwest Partnership on Carbon Sequestration (SWP)[330] to conduct research on CCS.[331] The SWP has begun work on the Farnham Dome Project near Price, Utah, to experiment with deep-saline CO_2 injection.[332] The project is designed to:

> validate the information and technology developed under the Characterization and Validation Phases relative to research and field activities, public outreach efforts, and regional characterization. Specific objectives include:
>
> - Develop an overall methodology that optimizes engineering and planning for future commercial-scale sequestration projects.
> - Conduct successful large-scale CO_2 injection projects targeting deep saline formations present throughout the western U.S.
> - Achieve a more thorough understanding of the science, technology, regulatory framework, risk factors, and public opinion issues associated with large-scale injection operations.
> - Validate monitoring, mitigation, and verification (MMV) activities and modeling, and equipment operations.
> - Refine capacity estimates of the target formation in the region, using results of the test.[333]

In general, the test project will follow an injection schedule for four years, 2008-2011, eventually injecting 900,000 metric tons (1 million U.S. tons) of CO_2 per year.[334] The project targets deep Jurassic-, Triassic-, and Permian-aged sandstone formations for injection because these "formations are also targets of potential commercial sequestration throughout the western United States."[335] The project will include a "dual completion" consisting of injection in two different formations at the same time within the same stratigraphy, so "portability of science and engineering results can begin to be evaluated."[336]

The Farnham Dome site will be extensively monitored to understand CO_2 movement and stability.[337] CO_2 for the project includes natural CO_2 and, potentially, CO_2 from a coal-bed methane (CBM) production field northwest of Price, Utah; the CBM operation currently emits more than 100,000 tons of CO_2 per year. A short pipeline would need to be added to facilitate injection of the captured CO_2 into the deep-saline reservoirs.[338]

DOE also contributed funding to a three-year project that studied the geologic storage potential of saline aquifers beneath the Colorado Plateau in Utah, including the Paradox Basin in southeastern Utah.[339]

Q. *Washington's CCS Efforts*

There is almost no coal produced in Washington.[340] Washington has one coal-fired power plant. The Centralia plant,

324. *See* Utah DEQ, Progress Report, *supra* note 322.
325. *See* CCGSW, *supra* note 320.
326. EPA, Underground Injection Control Program, http://www.epa.gov/ogwdw000/uic/wells_sequestration.html (last visited Mar. 30, 2011)
327. Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2), 75 Fed. Reg. 77230 (Dec. 10, 2010) (to be codified at 40 C.F.R. pt. 124).
328. *See* CCGSW, *supra* note 320.
329. *Id.*
330. *See generally* Southwest Partnership on Carbon Sequestration, http://www.southwestcarbonpartnership.org (last visited Mar. 10, 2011).
331. State of Utah, Climate Change, Carbon Capture and Geologic Sequestration in Utah, http://www.climatechange.utah.gov/CCGS_in_Utah.htm (last visited Mar. 10, 2011).
332. *Id.*
333. Southwest Partnership on Carbon Sequestration, Deep Saline Deployment Project: Farnham Dome Deep Saline CO_2 Sequestration Project: Fact Sheet 3, *available at* http://www.netl.doe.gov/publications/proceedings/08/rcsp/factsheets/24-SWP_Deep%20Saline%20Sequestration_PhIII.pdf [hereinafter Farnham Dome Fact Sheet].
334. *Id.*
335. *Id.* at 2.
336. *Id.*
337. *Id.* at 3-4.
338. *Id.* at 3.
339. *See* Utah Geological Survey, CO_2 Sequestration Project Overview: Reactive, Multi-phase Behavior of CO_2 in Saline Aquifers beneath the Colorado Plateau, *available at* http://geology.utah.gov/emp/co2sequest/overview.htm.
340. EIA Mine Type, *supra* note 1, shows no coal produced. But Source Watch says 2.6 million tons was produced in 2006, which is 0.2 % of the U.S. production. Source Watch, *Washington (State) and Coal,* http://www.sourcewatch.org/index.php?title=Washington_State_and_coal (last visited Mar. 10, 2011). EPA supports the lack of coal production in Washington State

owned by TransAlta Centralia Generation LLC, is a 1,376-MW plant located near Olympia. It is the largest source of GHG emissions in the state. On April 26, 2010, the company agreed to reduce its GHG emissions and is expected to eliminate coal as a fuel for the power plant by 2025.[341] It has a nameplate capacity of 1,460 MWs and was placed in service in 1972 and 1973. It has 5.2% of the state's generating capacity.[342]

Washington has set a GHG emissions reduction target to return to 1990 levels by 2020, 25% below 1990 levels by 2035, and 50% below by 2050.[343] In 2007, the state of Washington passed the Climate Change Mitigation Act that set emissions standards for electric power-generation.[344] All electric utilities that commence operations after June 30, 2008, must meet a performance standard for emissions that is equal to the lesser of 1,100 pounds of GHGs per MW-hour of electricity generated or the average emissions of a new combined-cycle natural gas-thermal electric-generation turbine as determined by the Washington Department of Community, Trade, and Economic Development.[345] Plants powered by renewable resources and existing cogeneration facilities powered by natural gas or waste fuel are considered in compliance with the emission standards.[346] Carbon that is captured and stored is also exempted from emissions calculations.

> The following greenhouse gas emissions produced by baseload electric generation owned or contracted through a long-term financial commitment shall not be counted as emissions of the power plant in determining compliance with the greenhouse gas emissions performance standard:
>
> (a) Those emissions that are injected permanently in geological formations;
>
> (b) Those emissions that are permanently sequestered by other means approved by the department; and
>
> (c) Those emissions sequestered or mitigated as approved under subsection (16) of this section [outlining criteria for approval of a CCS plan].[347]

The legislation also requires that any long-term financial commitments to purchase energy by electric companies or consumer-owned utilities may only be entered into with facilities that meet the emissions limits.[348]

As required by the Climate Change Mitigation Act, the Department of Ecology adopted rules in 2008 that include criteria for evaluating the carbon sequestration plan for any CCS used to avoid emissions limits.[349] The first rule includes a performance standard for sequestration, and another amends the state rules on underground injection to cover CO_2.[350] Carbon sequestration requires a permit issued under Washington's Waste Discharge Permit Program.[351] Washington State's underground injection rules for geologic sequestration of CO_2 are comprehensive and similar, but not identical, to the federal UIC rules. They aim to assure GHGs remain sequestered for at least 1,000 years.[352] The rules place the responsibility for the sequestration site on the operator until the post-closure requirements are completed and the Department of Ecology confirms, in writing, that the requirements have been met.[353] There also are air quality rules covering CO_2 emissions.[354]

On May 21, 2009, Gov. Chris Gregoire issued Executive Order No. 09-05, which directs state agencies to continue work with the WCI, work with companies emitting more than 25,000 metric tons on emissions reduction strategies, work with industry to develop emissions benchmarks, work with the Centralia coal-fired generation plant to reduce emissions by one-half, and take other measures to combat climate change.[355]

R. *Wyoming's CCS Efforts*

Wyoming has one underground and 19 surface coal mines. Its 2009 production was 431,107 million tons. This is 73.70% of western U.S. production and 40.11% of the nation's production, which makes Wyoming the number one coal-producing state in the nation.[356] Coal-fired power plants generate 95% of the electric power in the state.[357] There are 23 coal-fired power plants with a capacity of 6,168 MWs in Wyoming; four of the plants are larger than 500 MWs.[358] On a per capita basis, Wyoming is in first place among states for CO_2 emissions.[359]

DOE awarded $66.9 million to the Big Sky Regional Carbon Sequestration Partnership in November 2008, to demonstrate the suitability of the Nugget Sandstone formation in Wyoming for storage of over two million tons of CO_2. The CO_2 will come from Cimarex Energy's proposed helium and natural gas processing plant at Riley Ridge and be injected 11,000 feet below ground.[360]

Although Wyoming is only an observer in the WCI, and its congressional representatives have actively opposed

since 2000. U.S. EPA, *The Pacific and Central Coal Regions*, Attachment 11, EPA 816-R-04-003, at A11-1 (June 2004), *available at* http://www.epa.gov/ogwdw/uic/pdfs/cbmstudy_attach_uic_attach11_washington.pdf.

341. Source Watch, *Washington and Coal*, *supra* note 340.
342. *Id*.
343. Wash. Rev. Code Ann. §70.235.020 (West 2010).
344. Washington ESSB 6001 (2007); codifed at Wash. Rev. Code Ann. §§80.80.005 et seq. (West 2010).
345. Wash. Rev. Code Ann. §§80.80.40(1) & 80.80.50 (West 2010).
346. Wash. Rev. Code Ann. §§80.80.40(4) & (5) (West 2010).
347. Wash. Rev. Code Ann. §80.80.40(10) (West 2010).
348. Wash. Rev. Code Ann. §§80.80.60 & 70 (West 2010).
349. *See* Wash. Admin. Code §§173-218-010 through 173-218-130 (West 2010).
350. Wash. Admin. Code §§173-218-115 & 173-407-110 (West 2010).
351. Wash. Admin. Code §173-218-115-2 (West 2010).
352. Wash. Admin. Code §173-407-110 (West 2010).
353. Wash. Admin. Code §173-218-115 (West 2010).
354. *See* Wash. Rev. Code Ann. §70.94.151 (West 2010).
355. Wash. Exec. Order No. 09-05 (May 21, 2009).
356. EIA Mine Type, *supra* note 1.
357. Source Watch, *Wyoming and Coal*, http://www.sourcewatch.org/index.php?title=Wyoming_and_coal (last visited Mar. 10, 2011).
358. *Id*.
359. *Id*.
360. *Id*.

federal cap-and-trade legislation,[361] Wyoming has been very proactive in creating a legal framework for carbon sequestration. Recently, Wyoming enacted several laws to regulate carbon sequestration. Some of the major legislation is detailed below.

1. H.B. 89: Pore-Space Rights

Effective July 1, 2008, Wyoming H.B. 89 establishes the ownership of pore spaces under the surface for means of carbon sequestration.[362] Wyoming defines pore space as the "subsurface space which can be used as storage space for carbon dioxide or other substances."[363] Ownership of all pore spaces below the land and waters of Wyoming are to be vested in the owners of the surface rights above the pore space.[364]

When surface rights are conveyed, pore space below the strata is also conveyed unless pore space has previously been severed or is explicitly excluded in the conveyance.[365] Ownership of pore space shall be conveyed under the law of conveyance regarding mineral interests, but no mineral or other sub-surface agreement shall automatically convey pore space unless agreements explicitly state so.[366] "All instruments which transfer the rights to pore space under this section shall describe the scope of any right to use the surface estate. The owner of any pore space right shall have no right to use the surface estate beyond that set out in a properly recorded instrument."[367]

Transfers of pore space after July 1, 2008, may be deemed by the surface estate owner as null and void, if the agreement does not include specific descriptions of the location of the pore space being transferred.[368] "The validity of pore space rights under this subsection shall not affect the respective liabilities of any party and such liabilities shall operate in the same manner as if the pore space transfer were valid."[369]

Notice laws regarding notice to surface and mineral owners shall not be construed to require sending notice to pore-space owners unless a law explicitly includes pore-space owners.[370] Similarly, nothing in the bill is to change or alter the common law relating to rights or dominance of the mineral estate.[371] In determining priority of subsurface uses, mineral estates dominate, regardless of "whether ownership of the pore space is vested in the several owners of the surface or is owned separately from the surface."[372] The law also does not "alter, amend, diminish or invalidate rights to the use of subsurface pore space that were acquired by contract or lease prior to July 1, 2008."[373] The Act also provides that parties with geologic sequestration rights must be parties to a conservation easement that would deny them reasonable surface use.[374]

2. H.B. 58: CO_2 Ownership and Liability

Effective July 1, 2009, Wyoming H.B. 58, now codified as Wyo. Stat. Ann. §34-1-153 (2009), establishes ownership of material injected into geologic sequestration sites and liability related to sequestration sites. All CO_2 and incidental substances injected into a geologic sequestration site for the purpose of geologic sequestration are presumed to be owned by the injector of such material.[375] Consequently, all rights, benefits, burdens, and liabilities regarding the material shall also belong to the injector.[376] "This presumption may be rebutted by a person claiming contrary ownership by a preponderance of the evidence in an action to establish ownership."[377]

Owners of pore space or other persons holding rights to control the pore space, surface, or other subsurface rights shall not be liable for the effects of injecting CO_2 or incidental substances for the purpose of geologic sequestration solely because they consented to the injection.[378]

3. H.B. 90: Rules for Geologic Sequestration

Effective July 1, 2008, H.B. 90, now codified in Wyoming's statutes as §§35-11-313 and 3-5-501 (2008), regulates the permitting of carbon sequestration within the state of Wyoming. Under Wyoming law, carbon sequestration[379] is prohibited unless permitted by the Wyoming Department of Environmental Quality's Division of Water Quality.[380]

For temporary permits or pilot programs, Wyoming law directs the Administrator of the Division of Water Quality to issue permits under current administrative rules.[381] For requests for permanent sequestration, the Administrator shall recommend rules, regulations, and standards after receiving public comment on the issue and consulting with the Wyoming State Geologist, Wyoming Oil and Gas Conservation Commission, and the Carbon Sequestration

361. *See* Dustin Bleizeffer, *Senators Say They'll Fight Cap-and-Trade Legislation*, Billings Gazette, Aug. 20, 2009, http://billingsgazette.com/news/state-and-regional/wyoming/article_6d5b0f10-8d3c-11de-9c38-001cc4c03286.html (last visited Mar. 10, 2011).
362. Wyo. Stat. Ann. §34-1-152 (2009).
363. Wyo. Stat. Ann. §34-1-152(d) (2009).
364. Wyo. Stat. Ann. §34-1-152(a) (2009).
365. Wyo. Stat. Ann. §34-1-152(b) (2009).
366. *Id.*
367. Wyo. Stat. Ann. §34-1-152(f) (2009).
368. Wyo. Stat. Ann. §34-1-152(g) (2009). The description may include but is not limited to a subsurface geologic or seismic survey or a metes and bounds description of the surface lying over the transferred pore space. *Id.* In the event a description of the surface is used, the transfer shall be deemed to include pore space at all depths underlying the described surface area unless specifically excluded. *Id.*
369. *Id.*
370. Wyo. Stat. Ann. §34-1-152(c) (2009).
371. Wyo. Stat. Ann. §34-1-152(e) (2009).
372. *Id.*
373. Wyo. Stat. Ann. §34-1-152(h) (2009).
374. Wyo. Stat. Ann. §34-1-202(e) (West 2010).
375. Wyo. Stat. Ann. §34-1-153(a) (2009).
376. *Id.*
377. *Id.*
378. Wyo. Stat. Ann. §34-1-153(b) (2009).
379. Using CO_2 for enhanced oil and gas recovery approved by the Wyoming Commission on Oil and Gas is not included under these carbon sequestration provisions unless the operator converts the injection site to a sequestration site at the end of operations. Wyo. Stat. Ann. §35-11-313(b) and (c) (2008).
380. Wyo. Stat. Ann. §35-11-313(b) (2008).
381. Wyo. Stat. Ann. §35-11-313(d) (2008).

Advisory Board (created by this Act).[382] These rules and regulations shall include the following required information. First, to regulate and permit carbon sequestration, the Administrator shall create a subclass of wells able to protect human health, safety, and environment within EPA's Safe Drinking Water Act Underground Injection Control program.[383] Second, the administrator must create a permit application[384] for geologic sequestration. Applications for sequestration permits shall include the following:

(1) relevant geologic description of injection site;

(2) characterization of aquifers within injection zone that may be affected by injection and data describing projected effects;

(3) identification of all other drill holes and operating wells that exist within and adjacent to the proposed sequestration site;

(4) expected impact of injection on fluid resources, subsurface structures, and surface and necessary mitigation measures;

(5) plans and procedures for environmental surveillance, detection, prevention, and control for CO_2 migrating at or beyond boundary of the site;

(6) description of site and proposed sequestration facilities and documentation of all legal rights necessary to sequester CO_2 at the site.[385]

(7) proof that the proposed injection wells are designed, at a minimum, to the construction standards set forth by the Department of Environmental Quality and the Wyoming Oil and Gas Conservation Commission;

(8) a plan for periodic mechanical integrity testing of all wells;

(9) a monitoring plan to assess the migration of the injected CO_2 and to insure the retention of the CO_2 in the geologic sequestration site;

(10) proof of bonding or financial assures to ensure sequestration sites and facilities will be lawfully constructed, operated and closed;

(11) a detailed plan for post-closure monitoring, verification, maintenance and mitigation;

(12) proof of notice, including at a minimum publishing notice in a newspaper of general circulation in each county of proposed operation for four consecutive weeks and sending a copy of that notice to each surface owner, mineral claimant, mineral owner, lessee and any other owners of record of subsurface interests within one mile of the proposed boundary of the sequestration site.[386]

Third, in addition to these application requirements, the Administrator of the Division of Water Quality must require operators of sequestration sites to provide immediate verbal notification to the Department of Environmental Quality if any migrating CO_2 is discovered. The operator must then provide, within 30 days of detection, written notice to all surface owners, mineral claimants, mineral owners, lessees, and other owners of record of subsurface interests of the discovery.[387]

Fourth, the Administrator must promulgate "procedures for the termination or modification of any applicable Underground Injection Control (UIC) permit issued under Part C of the Safe Drinking Water Act if an excursion cannot be controlled or mitigated."[388] The Administrator may also set other needed conditions and requirements to manage CCS.[389]

H.B. 90 directs the State Oil and Gas Supervisor, the Director of the Department of Environmental Quality, and the State Geologist to convene a working group for the "purpose of developing an appropriate bonding procedure and other financial assurance methods to assure that adequate financial resources are provided to pay for any mitigation or reclamation costs."[390] At a minimum this bond or other financial assurance "shall provide assurance for closure and reclamation costs, post-closure inspection and maintenance costs and environmental monitoring, verification and control costs." As required by the law, the group reported the findings and recommendations to the joint Minerals, Business, and Economic Development and joint Judiciary Interim committees in September 2009.[391]

H.B. 90 also provides that the Director of the Department of Environmental Quality "shall recommend to the [Environmental Quality] Council any changes that may be required to provide consistency and equivalency between the rules or regulations promulgated under this section and any promulgated for the regulation of [CO_2] sequestration by the United States Environmental Protection Agency."[392] In addition, "the Wyoming [O]il and [G]as [C]onservation [C]ommission shall have jurisdiction over any subsequent extraction of sequestered carbon dioxide that is intended for commercial or industrial purposes."[393]

382. Wyo. Stat. Ann. §35-11-313(f) (2008).
383. Wyo. Stat. Ann. §35-11-313(f)(i) (2008).
384. At the time a permit application is filed, an applicant shall pay a fee to be determined by the director based upon the estimated costs of reviewing, evaluating, processing, serving notice of an application, and holding any hearings. The fee shall be credited to a separate account and shall be used by the division as required to complete the tasks necessary to process, publish, and reach a decision on the permit application. Unused fees shall be returned to the applicant. Wyo. Stat. Ann. §35-11-313(h) (2008).
385. The Department may issue a draft permit contingent on obtaining a unitization order pursuant to Wyo. Stat. Ann. §§35-11-314 through 35-11-317 (enacted through Wyo. H.B. 80 in 2009).
386. Wyo. Stat. Ann. §35-11-313(f)(ii)(A)-(N) (2008).
387. Wyo. Stat. Ann. §35-11-313(f)(iii) (2008).
388. Wyo. Stat. Ann. §35-11-313(f)(iv) (2008).
389. Wyo. Stat. Ann. §35-11-313(f)(v) (2008).
390. Wyo. Stat. Ann. §35-11-313(g) (2008).
391. *Id. See also* Wyoming Department of Environmental Quality, Carbon Sequestration Working Group, http://deq.state.wy.us/carbonsequestration.htm (last visited Mar. 13, 2011), for additional information on the working group and their publications.
392. Wyo. Stat. Ann. §35-11-313(j) (2008).
393. Wyo. Stat. Ann. §35-11-313(k) (2008).

4. H.B. 17: Financial Assurance and Long-Term Stewardship

In 2010, the Wyoming Legislature passed laws establishing a Geologic Sequestration Special Revenue Account and requiring certain financial assurances from CCS operators, including insurance. The Special Revenue Account is made up of fees collected by the Department of Environmental Quality to cover the costs of measuring, monitoring, and verifying a sequestration site after it receives a closure certificate.[394] It does not appear that Wyoming will assume liability for the site or the injected CO_2, even after issuing a closure certificate:

> The existence, management and expenditure of funds from this account shall not constitute a waiver by the state of Wyoming of its immunity from suit, nor does it constitute an assumption of any liability by the state for geologic sequestration sites or the carbon dioxide and associated constituents injected into those sites.[395]

The Act also adds financial assurance requirements to obtain a permit for CO_2 sequestration. The Administrator of the Water Quality Division must recommend further rules for CCS regulation. A CCS operator must now provide proof of a public liability insurance policy,[396] bonding and financial assurance, periodic reports substantiating the adequacy of financial assurances, and proof of compliance with financial requirements. The Administrator is also required to establish procedures for replacement of required financial instruments, procedures for terminating bonds and financial assurances no sooner than 10 years after completion of operations, recording requirements, so that permitted CCS sites can be located during a title search, and the fees that will be required to fund the Special Revenue Account, which may include a per-ton fee on injections or a closure fee.[397] The Department of Environmental Quality is also authorized to hire a full-time accountant to manage the financial assurances required by this act.[398]

5. Other Wyoming Legislation: H.B. 57 and S.B. 1

H.B. 57 of 2009 affirms that the mineral estate remains the dominant estate and has priority over pore-space ownership.[399] S.B. 1 of 2008 provides funding for CCS technologies and activities. Funds of $1,223,866 are made available for the evaluation of potential CO_2 sequestration sites and activities related to the advancement of clean coal and carbon management activities.[400] The spending bill also provides $1,822,481 for clean coal technology, directed at specified projects, including capture from coal combustion flue gas.[401]

II. Conclusion

Because of the federal government's failure to enact legislation regulating CO_2 or establish a national GHG cap-and-trade program, regional and state actions are becoming increasingly important.[402] While the fate of national and global actions to combat climate change are uncertain, much time, money, and planning has been invested by state and regional bodies to define, regulate, and promote CCS. The review of western states' initiatives shows that even states with such different stances on climate change and government regulation as California and Texas support CCS and have enacted extensive and often similar legislation to regulate it. Funding for CCS has increased dramatically over the past decade, and although it still faces substantial technological and financial hurdles, some of the political and legal hurdles are being addressed in several states.

The adoption of a cap-and-trade program for GHGs will give California an advantage in implementing CCS and clean coal technologies. By making carbon emissions a major cost item for electricity generators, cap and trade will make CCS more attractive and economically practical. If the choice is between investing in yearly allowances to continue the status quo or investing in new technology, large coal-fired plants may have the needed incentive to adopt CCS. However, analyses of CCS needs to take into account the regulatory burdens and the uncertainty generated by the social/political atmosphere surrounding the continued use of coal and other hydrocarbons.

Coal is still a major energy source for many states and regions that cannot easily or immediately be replaced. Increasing demand for energy may also counter several states' efforts to eliminate coal from their energy portfolios. One commentator's conclusion may be unavoidable: "For now, the only way to meet the world's energy needs, and to arrest climate change before it produces irreversible cataclysm, is to use coal—dirty, sooty, toxic coal—in more-sustainable ways."[403] Whether California's self-imposed cap-and-trade program or Texas' and Wyoming's industry-friendly regulations will be more conducive to advancing CCS remains to be seen.

394. Wyo. Stat. Ann. §35-11-318(b) (2010).
395. Wyo. Stat. Ann. §35-11-318(d) (2010).
396. Wyo. Stat. Ann. §35-11-313(f)(ii)(O) (2010).
397. Wyo. Stat. Ann. §35-11-318(f)(iv) (2010).
398. Wyo. H.B. 17, §4(a)(ii) (2010).
399. Wyo. Stat. Ann. §34-1-152 (2009).
400. Wyo. S.B. 1, §320(iii) (2008).
401. Wyo. S.B. 1, §325(a) (2008).
402. *See, e.g.*, *Plan B—Going It Alone: Regional Programs in North America*, Point Carbon (Feb. 25, 2010), http://www.pointcarbon.com/research/cmana/cmana/1.1416963 (last visited Mar. 30, 2011); Sean Pool. *The Proof Is in the Pudding: Regional Greenhouse Gas Initiative Shows Pollution Pricing Works*. Center for American Progress (Mar. 22, 2011), *available at* http://www.americanprogress.org/issues/2010/03/rggi_roadmap.html (last visited Mar. 30, 2011); Bruce Usher, *On Global Warming, Start Small*, N.Y. Times (Nov. 27, 2010).
403. James Fallows, *Dirty Coal, Clean Future*, The Atlantic (Dec. 2010), http://www.theatlantic.com/magazine/archive/2010/12/dirty-coal-clean-future/8307/ (last visited Mar. 13, 2011).