Coal Initiative Reports

White Paper Series

▸ State Options for Low-Carbon Coal Policy

Richard Cowart and Shanna Vale, *Regulatory Assistance Project*
Joshua Bushinsky and Pat Hogan, *Pew Center on Global Climate Change*

PEW CENTER ON Global CLIMATE CHANGE

Contents

Overview

There is growing state-level interest in accelerating the development of low-carbon coal technologies, including carbon capture and storage (CCS). CCS is a suite of technologies that removes carbon dioxide from exhaust streams and "sequesters" it underground in geologic formations including depleted oil and gas wells and brine-filled "saline" aquifers.[1] For many states, addressing climate change is the primary motivation to pursue these low-carbon technologies. For others, the primary motivation is to be able to continue to take advantage of their abundant coal resources in the future, when carbon dioxide emissions are expected to be constrained.

Many states are taking actions to reduce their greenhouse gas (GHG) emissions. They have adopted greenhouse gas emission targets and made commitments to low-carbon energy, and believe that these polices will result in job creation, air quality improvements, and reliable low-cost energy supplies. As states inventory their GHG emission sources, they recognize that coal-based electric power is one of the largest sources of carbon dioxide emissions, and that coal is likely to continue to provide a significant portion of electric power for the foreseeable future. The costs, scale of change, and security issues involved in moving away from the current, GHG-intensive U.S. power system limit the speed and degree to which non-coal generation technologies can be deployed. Consequently, given the need to rapidly reduce GHG emissions to address climate change, the carbon dioxide (CO_2) emissions from using coal to provide electric power need to be curtailed. CCS is the critical technology for doing this. Many states have put incentives in place to advance coal technology broadly; and a number of states, including Colorado, Montana, Wyoming and several Midwestern states are specifically focusing on CCS.

This paper provides an overview of options for states to encourage the deployment of carbon capture and sequestration. It describes actions—including legislation, regulations, and incentives—throughout the country. It also reviews in greater detail the range of policies available to state Public Utility Commissions for advancing deployment of CCS.

In reviewing the various actions taken by states to reduce emissions and promote low-carbon technologies for electricity production, several key lessons emerge. Many states are adopting meaningful incentives for integrated gasification combined cycle (IGCC) power plants, and, as a handful of states are beginning to demonstrate, a number of these incentives can apply to CCS as well. States also have a number of authorities relevant to advancement of clean coal power, particularly within the domain of state public utility commissions (PUCs). State commissions have a wide array of policy options available to them in pursuing this goal, and will play a crucial role in determining the speed and effectiveness with which such technologies are deployed.

---

[1] Saline aquifers are geologic storage reservoirs containing salt water. For sequestration purposes, ideal aquifers will be located at least 3000 feet below the ground surface, have several hundred feet of porous and permeable sands, and be overlain by at least one, and preferably more, thick and continuous seals—impermeable rock layers that keep the CO_2 trapped. Under these conditions, CO_2 would be stored very securely and efficiently, with the density and physical properties of a liquid due to the reservoir's depth.

Finally, while states face extra challenges and limitations in promoting low-carbon coal technologies that do not apply at the federal level, states also enjoy major advantages, such as their direct jurisdiction over many critical power plant issues—including siting and retail ratemaking—that federal agencies do not possess. Regardless of the final form of federal greenhouse gas rules, states have the chance to gain experience as first movers and policy innovators, and will play an important role in shaping a low-carbon future. Although national policy is essential, a proactive approach by state policymakers and regulators to drive CCS can reduce future compliance costs, speed the required technological developments, and pave the way for future national policy.

I. Introduction: State-Level Opportunities and Limitations

Although national policy is essential to achieve significant reductions in emissions from coal-fueled power plants, a proactive approach by states can reduce costs of compliance with future federal policies, speed the required technological developments, and pave the way for a national policy. In particular, state and federal efforts could be complementary and mutually reinforcing. For example, federal financial incentives combined with favorable public utility commission (PUC) treatment could be much more effective in advancing carbon capture and storage (CCS) than either initiative on its own. Further, states for which climate change, coal, or both are especially important could play an important role in speeding technological advance through support for CCS demonstration projects.

CCS demonstrations are needed to prove new technologies, lower the costs of existing and new technologies, and establish the viability of widespread, commercial-scale applications. States can play an important enabling role for such demonstrations and thereby accelerate the commercialization of CCS technologies. Decisions by public utility commissions in particular will be critical in determining how quickly these technologies penetrate a traditionally risk-averse industry. Utility commissions that allow cost recovery and create other incentives for low-carbon coal technologies may reduce their utilities' compliance obligations under future carbon constraints, help their industries provide low-carbon power to those states demanding it, and make progress towards their own GHG emission goals. Finally, states can assist in resolving institutional issues, including working out legal concerns surrounding CO_2 liability and siting protocols.

Technologies that can separate, capture, and store carbon from coal-fired power plants are in the research, deployment, and commercialization stages. However, the requisite suite of technologies has not yet been demonstrated as an integrated system at a commercial-scale coal-fired electric power plant. Use of high-efficiency designs—for example, ultra critical, super ultra critical, integrated gasification combined cycle (IGCC)—for new plants or repowering of existing plants offers incremental reductions in carbon dioxide emissions per unit of electricity generation. This will be important due to the efficiency losses entailed by CCS technology. Commercial power plant technologies exist that can provide efficiency rates well above those of most coal power plants currently in operation in the United States. Yet while high efficiency technologies should be used where feasible, they alone cannot adequately address carbon emissions from coal power.

While the federal government must ultimately provide the incentives and infrastructure necessary for deployment of low-carbon coal power, and while it is important to create a national strategy to develop the most promising innovations in a timely and cost-effective manner, the states also have important roles to play in testing policy approaches and spurring early technology improvements. The challenges and opportunities faced by states for creating a favorable policy environment for low-carbon coal power differ from the national situation. Hurdles faced at the state level that do not exist or are less severe at the national level include opportunities for emissions leakage to occur, interstate commerce issues in power markets and transport for sequestration, and perhaps most significantly, resource constraints. A large-scale, national CCS initiative would be better equipped to implement a long-range roadmap of CCS technology deployment, and to fund a suite of plants that could test CCS in a variety of configurations. However, with or without such a national program, the states enjoy major advantages and are essential actors in developing CCS on the ground because they have direct jurisdiction over many critical power plant issues.

States have jurisdiction in a number of key areas that enable them to require or promote GHG emission reductions from coal-based power. In particular, state agencies can make decisions about utility cost recovery, power plant siting, utility power portfolios and new build and power purchase decisions, and technology choices. States have unique authority over many aspects of electricity supply through their public utility commissions. Among other roles, these commissions are ultimately responsible for ensuring the supply of low-cost, reliable power to consumers, as well as achieving other policy goals demanded by legislatures and the public.

In addition, states can regulate air emissions, including greenhouse gas emissions, from coal-fueled power plants; they can set greenhouse gas emission standards for these facilities; and they determine whether facilities can receive operating permits. States can set rules for underground injection of carbon dioxide as long as their rules are consistent with any federal regulations, and through their oversight of the oil and gas industry states set the rules for the use of carbon dioxide (CO_2) in enhanced oil recovery (EOR). States can use their powers of taxation to favor particular technology choices and/or environmental performance, and can use their budgets to fund demonstration projects. Finally, states are well-positioned to engage and educate the public on CCS issues. Such outreach to local stakeholders can help alleviate public concerns on the health impacts and liability for any catastrophic release of CO_2. Acceptance of CCS by the public will be a critical determinant of the viability of this approach to address GHG emissions, so public education efforts by states are an important component to moving the nation towards a national CCS policy.

ARE STATE-LEVEL CCS INITIATIVES VULNERABLE TO “LEAKAGE”?

Those proposing state-level policies to reduce emissions from coal plants have to address the problem of “leakage,” which is a much more significant challenge for state programs than for uniform national regulations. “Leakage” here refers to an increase in emissions outside of a policy arena due to reductions required by the policy. Leakage can occur due to plants leaving, or reducing operations in, a state or region covered by a policy, and increasing operations and emissions outside the region. It can also result from electricity retailers choosing to increase purchases from plants not subject to the cap or standards. Such leakage is primarily due to rising costs of electricity generation within the state or region associated with the policy. Under a national-level policy such as a cap-and-trade program or an emission or technology standard, leakage is greatly reduced because it is encountered only insofar as electricity is imported from abroad.

Though a concern, states do have several options for addressing leakage, and policymakers must carefully consider both the risk of leakage and states’ options for managing it. First, leakage risk is a function of program cost. What drives emissions leakage is the cost of a policy, and whether firms can avoid that cost by shifting production out of state. Thus states attempting to minimize leakage must first of all minimize costs. Among state options for addressing climate change, greenhouse gas cap-and-trade programs have relatively low leakage risk, because such programs minimize costs relative to more traditional command-and-control programs. Command-and-control policies are therefore more likely to drive leakage than cap and trade. In addition, design choices made in the development of cap-and-trade programs (such as the inclusion of banking and other flexibility mechanisms) can further reduce costs.[2]

[2] “Climate Change 101: Cap and Trade.” Pew Center on Global Climate Change, forthcoming.

Second, energy efficiency is a key strategy for minimizing leakage. Energy efficiency reduces electricity demand and therefore program costs, thereby minimizing the potential for leakage. According to a report evaluating leakage potential under the Regional Greenhouse Gas Initiative (a multi-state GHG cap-and-trade agreement), scenarios which included aggressive energy efficiency policies and measures showed significantly lower costs to consumers, lower power costs generally, and less leakage than those without such policies.[3] Third, a number of policies can address emissions without directly capping them. For example, states can address the carbon emissions of imported power directly, by covering imported power in a cap-and-trade program, or setting emission performance standards that cover imports (perhaps by setting such standards on load-serving entities in a state or region). Finally, it is important to note that the greater program's geographic coverage, the lower the leakage risk. Leakage risk is thus lower for national programs than it is for regional programs, and lower for regional programs than for individual state programs.

Finally, states do have the authority to prevent leakage and address the GHG emissions from electricity imports as long as they do so in a way that does not discriminate against imports in favor of instate power.[4] This restriction significantly limits the policy options available to states to control leakage of emissions outside their borders. Technical issues also arise in attempting to address the greenhouse gas emissions from imported power. For example, it is often difficult to trace the origins of purchased power in order to determine the emissions initially associated with the generation of that power. Doing so requires sophisticated reporting and tracking systems.

In addition to the challenges of addressing power imports, states have significantly fewer financial resources to encourage CCS than the federal government. Since state taxes and budgets are generally much lower than federal ones, state-level tax incentives and other subsidies in general provide a much smaller financial benefit to technology developers than federal tax credits or other subsidies. In addition, most states face severe budget constraints resulting from lower levels of tax collection and balanced budget requirements.

However, states have other tools at their disposal to create incentives that the federal government does not. Some coal-dependent states might readily devote substantial resources to demonstrating a technology that is critical to the future of their coal industries. One sees this phenomenon already, as a number of states are adopting meaningful incentives for integrated gasification combined cycle (IGCC) power plants. Many of these incentives could be applied to CCS as well. For instance, states have the option of streamlining permitting and siting processes to facilitate CCS development, and several have created Clean Coal Programs or provided state funding through other mechanisms.[5] States' authorities provide opportunities for experimentation at the state level in the absence of federal policy and for raising the bar once federal climate policy is in place. The challenge is the difficulty of coordinating state actions and the potential for a patchwork quilt of different policies. The potential for complementary and mutually reinforcing state and federal efforts is vast.

---

[3] Recommendations and leakage projections from "Potential Emissions Leakage and the Regional Greenhouse Gas Initiative (RGGI): Evaluating Market Dynamics, Monitoring Options, and Possible Mitigation Mechanisms." Initial Report of the RGGI Emissions Leakage Multi-State Staff Working Group to the RGGI Agency Heads, March 2007. Full report available online at http://rggi.org/docs/il_report_final_3_14_07.pdf.

[4] Under the Interstate Commerce Clause of the US constitution, states are constrained in the manner in which they can place limitations on the sale of goods and services across state lines, particularly if the limitation discriminates against out-of-state goods whether explicitly or implicitly. Limitations have been deemed permissible when the law in question is necessary to promote and protect the environmental and public health of the state's inhabitants. Thus, the courts are often faced with a balancing test that asks whether the burden on commerce is greater than the environmental and/or public health benefits of the state law. Legal precedence is blurred on the issue, as both sides of the debate can point to rulings in their favor. Legal experts agree that policy makers need to very carefully consider the language and intentions of any state or regional initiative to address leakage. Therefore, a policy that appears least discriminatory to out-of-region emitters is the most legally attractive.

[5] Colorado (Clean Energy Development Fund), Illinois (Office of Coal Development, Illinois Coal Demonstration Program, Illinois Coal Revival Program and others), Kansas HB 2429 (energy enhancement and environmental reclamation fund), Minnesota 216B.1694, Minn. Stat. 2006 (Renewable Development Account), New York (Advanced Clean Coal Power Plant Initiative), Ohio § 1551.32 (Ohio Coal Development Office), West Virginia SB631 (West Virginia Clean Coal Technology Council), Wyoming (Wyoming Infrastructure Authority).

II. State-Level Low-Carbon Coal Policy Options and Lessons Learned

This section reviews the policy options available to states to promote GHG reductions in the power sector, including emissions from coal-fired power plants, and briefly summarizes current state initiatives to support, encourage, and facilitate deployment of CCS. Some of the policy options reviewed here, particularly generator standards, correspond to those analyzed in the Pew Center's companion papers on national policy, and this paper takes into account additional considerations that obtain if analogous policies are applied at the state level.[6] Other policies discussed below, such as feebates, are offered as additional options available to policymakers at both the state and federal levels. For the most part, this section focuses on policies that are not specifically within the domain of public utility commissions; the specific regulatory steps state commissions can take to promote low-carbon coal power are discussed in section III.

A. POLICY OPTIONS

1) Generator Performance Standards. This approach is modeled after the New Source Performance Standard (NSPS) regulations under the federal Clean Air Act. Under this approach, each coal- or fossil-fueled generation unit or plant must meet a standard, for example, a maximum annual amount of CO_2 emissions or a maximum rate in CO_2/kWh. Traditionally, such standards have initially applied only to new plants, with existing plants required to meet the standard only as of some future date or event.

If set low enough, CO_2 emission standards would have the effect of forcing coal-fueled generators to shift to low-carbon generation options such as renewables, nuclear power, or CCS systems. Such performance standards have been adopted or proposed in a number of states.[7]

State-level considerations. Performance standards fit relatively easily into existing state processes for permitting and monitoring new facilities. However, such standards have the potential to drive leakage, because a plant owner may choose to locate in another state where similar standards do not apply. One way to reduce leakage under a performance standard approach is to bar regulated electricity retailers (load serving entities) from entering long-term purchase contracts with generators that do not meet a specified CO_2 performance standard. However, this type of requirement on contracts may not be sufficient, in part because power contract arrangements have shifted in recent years. Utilities are increasingly contracting for power not associated with a specific plant in order to reduce their risk and to avoid obligating specific generation to specific demand. State policies that require contracts to specify individual generators as sources could decrease provider flexibility and put

6 Forthcoming.

7 California: CA AB 1368 (2006); Montana: MT HB 25 (2007); Oregon: OR Rev. Stat. § 469.503 (2005); Washington: WA SB 6001 (2007); Wisconsin: Considered in Department of Natural Resources and Public Service Commission of Wisconsin*, Integrated Gasification Combined Cycle Draft Report: Benefits, Costs, and Prospects for Future Use in Wisconsin,* p. 56 (June 2006) [hereinafter Wis. Draft Report].

upward pressure on power prices. State policies that set GHG standards will have to respond to this changing contract environment in order to reduce emissions and minimize impacts on electricity prices.

Relevant State Experience. While generator performance standards for conventional pollutants are widespread, such standards for CO_2 have been imposed in just a few jurisdictions, including Washington, Montana, Oregon, and Massachusetts.

Oregon's statute requires its energy facility siting council to establish carbon dioxide emissions standards[8] for new plants but allows the use of a one-time payment for offsets for a portion of emissions as one compliance method.[9] Washington's statute is similar to Oregon's.[10]

In May 2007, Montana adopted a CO_2 emissions performance standard for electric generating units in the state with the enactment of HB 25. The bill prohibits the state Public Utility Commission from approving electric generating units primarily fueled by coal unless a minimum of 50 percent of the CO_2 produced by the facility is captured and permanently geologically sequestered. The standard applies only to electric generating units constructed after January 1, 2007. A separate bill introduced in the Montana legislature proposes the strongest emissions performance standard in terms of advancing CCS. Montana House Bill 282 would require the Board of Environmental Review to apply requirements to any construction permit applications filed for coal-fired electrical generation facilities or synthetic fuel facilities for (1) the capture of carbon dioxide at the site, (2) the transportation of carbon dioxide, if necessary, and (3) the permanent storage of carbon dioxide in a geologic formation or verification that 100 percent of the carbon dioxide emissions from the proposed facility will be offset.[11]

An approach akin to a generator performance standard has also been proposed in Iowa. It would require new power plants to achieve carbon neutrality—meaning that the facility could not contribute to any increase in statewide emissions of greenhouse gases.[12] The applicant for a new power plant would have to obtain preconstruction approval of its carbon-neutral plan, which could rely upon energy conservation, demand-side management, renewables, or carbon sequestration.[13]

2) Retailer Standards. The obligation to meet a carbon or CCS Emissions Performance Standard (EPS) could be placed on the entities that sell electricity to end users (the load serving entities, or retailers). This approach is modeled after Renewable Portfolio Standards (RPS). Retailer standards to encourage CCS could take a variety of forms, including:

a. Requiring that an increasing percentage of electricity sold come from sources incorporating CCS;

b. Setting a declining CO_2/kWh standard for the entire portfolio with the rate starting close to the current average for the state;

[8] See Oregon Revised Statutes § 469.503 (2005).
[9] See id. at § 469.503(2)(b). By permitting the use of offsets to counterbalance the higher emission rates of conventional coal units, the Oregon approach does not bar new PC additions or advance CCS alternatives as bluntly as the California standard described in the next section. Oregon's legislature has also recently considered a "carbon fee." HB 3261, 74th Leg., Reg. Session (Or. 2007).
[10] Washington Revised Code § 80.70.020(4) (2004); Wash. Admin. Code § 173.407.020 et seq. (2004).
[11] Montana HB 282, 60th Leg., Reg. Sess. (Mt. 2007) (amending MCA § 75-2-211(3)(k)).
[12] See Iowa S.F. 391, 82nd General Assembly, Regular Session (Ia. 2007).
[13] *See id*.

c. Requiring an increasing specified percent of electricity sold to meet a CO_2/kWh rate achievable only by coal-fueled units that are using CCS;

d. Requiring new long-term power purchase contracts to meet a specified CO_2/kWh standard

Under the first three of these approaches retailers would be allowed to trade credits among themselves to meet the standard, as is practiced under many state RPSs.

State-level considerations. This approach can avoid leakage, because it can cover imported electricity. It also fits relatively easily into existing state processes for regulating load serving entities, including use of RPSs, demand side management programs, efficiency portfolio standards, and resource planning. A load-serving entity also has more options than an electric generator to reduce GHG emissions, providing some advantages over a generator standards approach. A CCS-specific requirement can be administered much like other special tiers contained in various state RPS rules. CCS credits can be created for each MWh of generation, and then acquired by complying retailers independently from power sales and physical delivery paths on the grid.

Applying a GHG performance standard across an entire power supply portfolio is possible, but is not as straightforward. There are substantial challenges to associating emissions at the point of generation to particular power sales—an attribution necessary to implement an effective retailer standard approach to CO_2 emissions. To determine whether a load-serving entity is in compliance, it is necessary to determine the GHG emissions associated with the electricity it purchases. If a load-serving entity can purchase electricity from any seller, a system capable of tracking emissions from the point of generation to the point of sale to a load-serving entity is needed. The Northeast's NEPOOL GIS system is capable of tracking power plant emissions, and other power pools are developing similar systems, including the PJM power pool in the Mid-Atlantic. These software programs are capable of assigning environmental attributes, including carbon content, to each MWh moving through the system, but it would take a deliberate public effort to do so.[14]

Relevant State Experience. California now requires electricity retailers entering into new, long-term contracts to meet a CO_2 /kWh emission rate typical of natural gas-based combined cycle plants. The lack of a real-time tracking system in the western states that determines CO_2 emission rates of purchased electricity and its associated generators is one of the major technical barriers to implementation of California's program as originally envisioned. As a result, California now requires that major new or renewed baseload electricity contracts of five years or more be with generators that can meet a standard of 1,100 pounds of CO_2 per megawatt-hour.[15] For states interested in incentivizing low-carbon coal imports, GHG emission requirements on long-term contracts may not be sufficient, in part because power contract arrangements have shifted. As noted above, utilities are increasingly contracting for power not associated with a specific plant, so state policies that set GHG standards will have to respond to the changing contract environment, and emission tracking systems will become increasingly important to prevent an increase in power with unspecified origins.

[14] Such systems also need rules to assign average emission rates to imports or other power sources outside of the measured system.
[15] "PUC Sets GHG Emissions Performance Standard to Help Mitigate Climate Change." California Public Utilities Commission news release, January 25th, 2007. Available online at http://docs.cpuc.ca.gov/published/News_release/63997.htm. Accessed December 13, 2007.

A recently enacted proposal in Washington takes an approach similar to California's.[16] It differs from California's statute in that it requires the state's Department of Ecology and its Energy Facility Site Evaluation Council to establish regulations governing the use of geological carbon sequestration to satisfy the standard.[17]

A growing number of U.S. states have created Renewable Portfolio Standards (RPSs) that require an increasing fraction of each utility's power supply to come from environmentally preferred sources. These RPSs generally operate as retailer standards, with load-serving entities required to supply a specific percent of electricity from sources classified as renewable.

Many states have tailored their Renewable Portfolio Standards to encourage investment in particular types of renewable energy.[18] New Mexico mandates that wind and solar each provide at least 20 percent of the total renewable energy supplied by IOUs.[19] In April 2007 the Maryland Public Service Commission bolstered the state's RPS goal an additional two percent by 2022 to be supplied exclusively by solar power.[20] North Carolina has small carve-outs for electric power sourced from both solar and swine waste.[21]

These observations raise the question of whether it is better to keep renewable mandates and CO_2 or CCS mandates separate or to integrate them. Clearly the answer will depend on a state's objectives. Under an integrated approach, both CCS and renewables could be considered low-carbon energy sources and the retailer would have an obligation to supply to its customers a certain percentage of low-carbon energy, with CCS as one option. To accomplish this, the RPS would be converted to a "Low Carbon Standard" that would include fossil generation with an adequate degree of sequestration. Pennsylvania has taken a similar approach via its Alternative Energy Portfolio Standard (AEPS). Pennsylvania's AEPS includes IGCC and coal waste-fueled plants, although it does not include CCS.

A CO_2 emission standard (Low Carbon Portfolio Standard) might be attractive in a highly coal-dependent state although, depending on the relative costs of CCS and renewables, it might incentivize the latter less than a traditional RPS. If the primary objective is to reduce GHG emissions, a low-carbon standard placed on retailers might make sense, particularly in heavily coal-dependent regions. However, there are many reasons for encouraging renewables other than climate considerations, such as economic development and air quality. Over half the U.S. states now have RPSs. Many of these states have successfully driven significant investment in renewables, and as noted above, many states have specific set-asides for particular types of renewable energy (e.g., biomass or solar). In a similar fashion, CCS could be included as a separate obligation rather than integrated into an existing RPS. Under such an approach, a specific set-aside, or percent of CCS-based electricity, would be required and added as a separate obligation on load-serving entities, without compromising existing renewable obligations.

---

[16] The proposal also provides a two percent higher rate of return for investments in efficiency. See Washington SB 6001, 60th Leg., Regular Session (Wa. 2007).

[17] See id. at § 5(11) (These regulations must include provisions for: financial assurance of effectiveness, time of commencement of sequestration, monitoring and verification, penalties for failure, purchasing of offsets in the case of failures, and public notice and comments on the plan.).

[18] In addition to those states listed in the text, other states with carve-out requirements for solar or other renewable technologies include Colorado, Delaware, Nevada, New Jersey, and Pennsylvania.

[19] http://www.dsireusa.org/library/includes/incentivesearch.cfm?Incentive_Code=NM05R&Search=TableType&type=RPS&CurrentPageID=7&EE=1&RE=1

[20] http://www.dsireusa.org/library/includes/incentivesearch.cfm?Incentive_Code=MD05R&Search=TableType&type=RPS&CurrentPageID=7&EE=1&RE=1

[21] http://www.dsireusa.org/library/includes/incentivesearch.cfm?Incentive_Code=NC09R&Search=TableType&type=RPS&CurrentPageID=7&EE=1&RE=1

3) Cap and Trade. This approach is modeled after the U.S. Acid Rain Program and other systems such as the European Union Emissions Trading Scheme. Under a traditional cap-and-trade approach, the total annual CO_2 emissions from all sources covered by the program must be less than a specified number of tons. Under the Acid Rain Program for sulfur dioxide (SO_2), the obligation to comply with the cap has been placed on the generators. It would, however, be possible to place the obligation on retailers (load-serving entities) or "first deliverers"[22] in areas where emission tracking systems are sufficiently accurate. A cap-and-trade program targeted at utilities could be a stand-alone program or could be incorporated into an economy-wide cap and trade program. A cap could cover all fossil-fuel plants, all coal-fired units, all units above a certain size, or units with emission levels above a specified rate.

State-level considerations. State-level generator-based cap-and trade programs for GHG emissions fit relatively easily into existing programs for capping and trading NO_x and SO_2. However, under this type of system, load-serving entities might import electricity from states where generators are not subject to a cap. The significance of this issue varies from region to region. For example, such imports are of particular concern in California, where imported power can account for 50 percent of the state's annual electric sector CO_2 emissions. In part to address leakage, the California Public Utilities Commission is considering a load-based or first-deliverer-based cap-and-trade program.[23] Oregon is considering adopting a load-based standard approach.[24]

The northeast Regional Greenhouse Gas Initiative (RGGI) is a generator–based cap-and-trade program that will enter into effect in ten northeastern states in 2009. Although RGGI has identified leakage as an issue, thus far RGGI participants have agreed only to track imports more carefully and leave open the possibility of taking corrective actions should imports increase. In March 2007, a multi-state staff working group issued its initial report on addressing potential emissions leakage under RGGI. Under the "middle-of-the road" modeling scenario used as the primary basis for estimating the projected impacts of RGGI, cumulative emissions leakage under the program is estimated to be 27% of net CO_2 emissions reductions achieved through 2015. The report highlights the importance of being able to track and verify the environmental attributes of all power used in the RGGI states, and includes a number of recommendations for the establishment of a robust monitoring and verification system to help track these attributes and possible emissions leakage. The report also recommends a number of policy options states might pursue in order to address leakage, including policies that reduce electricity demand, others that directly address carbon emissions without capping them (such as carbon adders or emissions rate mechanisms) and discussion of an emissions cap on load-serving entities.[25]

4) Feebates. A feebate is a policy that provides "rebates" to environmentally or otherwise high-performing technologies, funded by fees on technologies that perform less well. In the context of electricity climate policy, this would mean changing behavior by simultaneously discouraging investment in carbon-intensive

[22] The term "first deliverer" refers to the entity that first sells power in a state from an out-of-state generation source. The first deliverer may be a generator, power marketer, or load serving entity.
[23] California Public Utilities Commission Docket No. R06 04 009
[24] Schwartz, Lisa, Senior Analyst, Oregon Public Utility Commission, "Oregon on IGCC-Related Issues," presented at Pacificorp IGCC Working Group Meeting at 3 (September 14, 2006).
[25] Recommendations and leakage projections from "Potential Emissions Leakage and the Regional Greenhouse Gas Initiative (RGG): Evaluating Market Dynamics, Monitoring Options, and Possible Mitigation Mechanisms." Initial Report of the RGGI Emissions Leakage Multi-State Staff Working Group to the RGGI Agency Heads, March 2007. Full report available online at http://rggi.org/docs/il_report_final_3_14_07.pdf. The Integrated Planning Model (IPM) runs and leakage projections are also available at http://rggi.org/documents.htm, dated October 11, 2006.

electricity generation while providing a financial incentive and support to low-carbon projects.[26] One option would be for fees to be levied on a per-kWh-of-electricity-generated basis at coal-fueled generation plants. Funds generated would be used to upgrade existing plants to include CCS equipment, or build new units incorporating such technologies.[27] At least initially, there are likely to be many more entities subject to the fee than CCS demos eligible for the rebate. Thus the fee itself would provide a modest disincentive to using coal without CCS and a modest incentive to use alternatives to coal, and the rebates would provide a more powerful incentive to use CCS.

State-level considerations: The feebate would function similarly at the state and federal level, except for the potential to shift non-CCS coal power out-of-state. If the fee were relatively modest (at a level only sufficient to create enough funds for a few demonstration units) it would be unlikely to have this effect. However, even a modest fee on electricity generated would give load-serving entities some incentive to purchase electricity from plants not subject to the fee. If those plants were non-emitting, that would reduce GHG emissions. If those plants were emitting, and imports were not covered by the fee, then the state would collect fewer fees and be able to fund fewer projects.

Some coal-dependent states might be willing to devote substantial resources to demonstrating a technology that is critical to the future of coal. One sees this phenomenon already, as a number of states are adopting meaningful incentives for IGCC, and similar incentives could be applied to CCS as well. In addition, some coal-fueled plants may be interested in hosting demonstration projects in order to reap the benefits of being a "first mover." Such plants might support a state-imposed fee for the purpose of supporting CCS demonstrations.

Relevant State Experience. While no state has instituted a feebate system devoted to the advancement of CCS, almost half the states have funds, often called "public benefit funds," or "system benefit funds," dedicated to supporting energy efficiency and renewable energy projects. These funds serve similar functions to, and could serve as potential models for, such a feebate approach. The necessary funds are collected either through a small charge on the bill of every electric customer or through specified contributions from utilities. These funds often support specific, high-priority energy projects, including R&D&D efforts, to help build more sustainable energy and power systems. Publicly managed clean energy funds and state agencies from 18 of these states have formed the Clean Energy States Alliance to coordinate public benefit fund investments in renewable energy. The Clean Energy States Alliance is composed of funds in Alaska, Arizona, California, Colorado, Connecticut, Illinois, Maryland, Massachusetts, Minnesota, New Jersey, New Mexico, New York, Ohio, Oregon, Pennsylvania, Rhode Island, Vermont, and Wisconsin. To date, no state fund has focused on providing financial support to CCS projects, but this is an application that would be consistent with the overall thrust and history of the mechanism, particularly if funds were collected and administered so as not to reduce support for the smaller-scale renewable and distributed efficiency and power projects

5) Combined Approaches. Under a combined approach, one or more of the above policies could be implemented simultaneously. Some possible combined approaches include combining a feebate with a generator performance standard, or incorporating a feebate into a cap-and-trade system. The combination of a feebate with a generator performance standard is intended to overcome a weakness of standard-based approaches as they have operated to date; namely, that generator standards have generally only applied to new units,

[26] Feebates have been proposed in the fuel economy context, where fees would be imposed on the sale of vehicles with low fuel economy and the funds generated would be used to provide rebates to purchasers of vehicles with high fuel economy, thus lowering the purchase price

[27] See the accompanying papers, Vello, 2006 and Pena and Rubin, 2006 for a detailed explanation of how such an approach would work at a national level.

with the expectation that existing plants would be replaced. However, as the life of existing units has been extended, the new standards have failed to apply to all plants. A fee added to a generator standard approach could be structured to strongly discourage life-extension of plants that fail to install CCS.

B. CURRENT STATE GHG REDUCTION AND CCS DEPLOYMENT INITIATIVES

A number of states are using their numerous relevant authorities to reduce greenhouse gas emissions or to encourage CCS demonstrations. These initiatives are briefly reviewed by topic below. Further details of state initiatives are provided on a state-by-state basis in the appendices.

1. Key efforts to reduce power sector GHG emissions specifically[28] include:

- Under the northeast Regional Greenhouse Gas Initiative (RGGI) ten states—Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont—have agreed to reduce CO_2 emissions from power plants in the region. Using a cap-and-trade system, the states have agreed to return emissions to current levels by 2009 and to reduce emissions 10 percent by 2016. The states are in the state-by-state process of adopting an agreed-upon model rule for implementing the program. In the absence of federal policy, such a regional approach is relatively more efficient and effective than a single-state effort.

- California's AB 32, The Global Warming Solutions Act of 2006, sets a greenhouse gas target for the state that reaches 1990 levels by 2020. The state will need to address emissions from the power sector, including imports, in order to meet the law's requirements. The California Public Utilities Commission (CPUC) and the California Energy commissions jointly initiated proceedings to consider a "load-based" cap on greenhouse gas emissions from investor owned utilities. This proceeding is also considering a "first deliverer" approach in which the generator is responsible for the emissions from power produced instate and the importer is responsible for the emissions associated with the generation of the power they import.

- The Western Climate Initiative was established in February 2007 by the governors of Arizona, California, New Mexico, Oregon, and Washington as a joint effort to reduce greenhouse gas emissions and address climate change. The states of Montana and Utah, as well as the Canadian Provinces of British Columbia and Manitoba, joined the initiative later in 2007. The member states and provinces set a regional emissions target of 15% below 2005 emissions levels by 2020 and have committed to design a market-based system by August 2008—such as a cap-and-trade program covering multiple economic sectors—to aid in meeting the target. Members will also set up an emissions registry and tracking system. The initiative builds on work already undertaken individually by several of the participating states.

- In November 2007, six states and one Canadian Province established the Midwestern Regional Greenhouse Gas Reduction Accord. Under the Accord, members agree to establish regional greenhouse gas reduction targets, including a long-term target of 60 to 80 percent below current emissions levels, and develop a multi-sector cap-and-trade system to help meet the targets. Participants will also establish

[28] In addition to the numerous state policies to promote energy efficiency, renewable power, combined heat and power, and other resources that have multiple goals, including the reduction of GHGs.

a greenhouse gas emissions reductions tracking system and implement other policies, such as a low-carbon fuel standard, to aid in reducing emissions. The Governors of Illinois, Iowa, Kansas, Michigan, Minnesota, and Wisconsin, as well as the Premier of the Canadian Province of Manitoba, signed the Accord as full participants, while the Governors of Indiana, Ohio, and South Dakota joined the agreement as observers. According to the agreement, the Accord will be fully implemented by mid-2010.

- Both Oregon and Washington have carbon offset requirements for new power plants.[29] Oregon requires new power plants to offset approximately 17 percent of anticipated CO_2 emissions or pay an up-front, one-time fee per ton of carbon dioxide emitted, while Washington requires new power plants to offset approximately 20 percent of anticipated CO_2 emissions through third-party mitigation, carbon credit purchase, or investment in mitigation projects such as cogeneration.

2. Key efforts to require, or provide incentives for, CCS include:

- California is pursuing a number of policies that may drive low-carbon coal power investments in neighboring states that export coal power to California. California law SB 1368 sets a GHG emissions performance standard at the CO_2/kWh emission rate typical of natural gas combined cycle plants for all new major, baseload, long-term electricity contracts. This standard has the effect of discouraging the use of coal without CCS. Utilities can comply with the standard by purchasing power from coal-fired generators in, or exporting into, the state that capture and sequester approximately 40 percent of their carbon dioxide emissions. Or they can comply by buying power from gas-fired or other low-emitting generators. While California imports less than 20 percent of its electricity from out-of-state, 50 percent of the state's GHG emissions associated with electricity are from imports, mostly from coal-fueled plants. The state's imported electricity comes from western states where a number of new coal power plants are scheduled for construction. SB 1368 provides some incentive to design and equip these new plants with CCS.

- In November 2007, the Governors of 11 midwestern states and the Premier of one Candadian province individually adopted all or portions of an Energy Security and Climate Stewardship Platform for the Midwest. The state of Missouri later adopted portions of the agreement as well.[30] By endorsing components of this platform, members agree to specific objectives and measurable goals for energy production and use in the region, and to work towards these goals by implementing a mix of policy recommendations included in the Platform. In addition to goals related to energy efficiency, renewables, and biofuel production, the Platform lays out explicit objectives with respect to carbon capture and storage. Members agree to have in place a regional regulatory framework for CCS by 2010, and by 2012, to have sited and permitted a multi-jurisdiction CO_2 transport pipeline and have in operation at least one commercial-scale coal-powered IGCC power plant with CCS, with additional plants to follow in succeeding years.

- In May 2007 Montana adopted a CO_2 emissions performance standard for electric generating units in the state with the enactment of HB 25. The law prohibits the state Public Utility Commission from

[29] See Oregon Revised Statutes 469.503; Revised Code of Washington 80-70-010 et seq.

[30] Members include Indiana, Iowa, Kansas, Michigan, Minnesota, Ohio, South Dakota, Wisconsin, and Manitoba. The full Energy Security and Climate Stewardship Platform, and accompanying agreements, are available online at http://www.midwesterngovernors.org/resolutions/MGA%20Platform1_Layout%201Right.pdf. Accessed December 6, 2007.

approving electric generating units primarily fueled by coal unless a minimum of 50 percent of the CO_2 produced by the facility is captured and permanently geologically sequestered. The standard applies only to electric generating units constructed after January 1, 2007.

- In 2006, Colorado adopted legislation providing incentives for IGCC power plants of 350 MW or less that use Colorado or other western coal to generate electricity and that demonstrate the capture and sequestration of a portion of the project's CO_2 emissions. Incentives for projects meeting these criteria include mechanisms for cost recovery (including full life-cycle capital and operating costs); financial support for study, engineering, and development from a clean energy development fund; and support in obtaining federal funding, among others.

- Wyoming and California are working together to develop an IGCC/CCS project and to jointly seek federal funds for it.[31]

- Several states are allowing or considering the use of eminent domain for CO_2 pipelines and storage. For example, a bill has been introduced in the Montana Legislature to allow the inclusion of pipelines and storage in the state's eminent domain powers.[32] Minnesota provides an innovative energy project with the power of eminent domain, enabling it to acquire the property for its facility and transmission infrastructure.[33] Mississippi may include carbon dioxide pipelines within the class of common carriers eligible for eminent domain proceedings.[34]

- Texas has enacted legislation that would relieve companies from liability associated with the escape or migration of captured and stored carbon dioxide, and Illinois has twice considered similar legislation.[35]

- Colorado has pledged to support a utility's efforts to seek federal funding, and West Virginia may follow suit.[36]

3. Closely Related IGCC Initiatives:

Although some states are pursuing CCS incentives, many more states are providing incentives for IGCC. The following state-level IGCC incentives could be extended to CCS:

- Pennsylvania includes IGCC and waste coal in its Alternative Energy Performance Standard and is buying power under long-term contract with a coal gasification plant.

- Illinois is assisting with front-end engineering design (FEED) costs for three coal gasification projects at a cost of a few million dollars per project.[37] FEED includes many of the major upfront tasks for a project, such as planning documents, requests for proposals, and cost estimates. By paying for upfront

[31] Steve Ellenbecker, Energy Advisor to Wyoming Governor David Freudenthal. Personal Communication, February 2008.
[32] Montana HB 24, 60th Legislature, Regular Session (MT 2007).
[33] 216B.1694(2)(a)(3), Minnesota Statutes 2006.
[34] Mississippi SB 2152, 122nd Legislature, Regular Session (MS 2007); see also H.B. 300, 122nd Leg. Sess. (MS 2007)(in the Senate as S.C.R. 509).
[35] Texas Natural Resources Code Ann. § 119 (2006) (H.B. 3110, 80th Leg. Sess., Reg. Sess. (TX 2007) would amend this statute to require the attorney general to defend any claim of liability against an owner or operator of a sequestration project and indemnification); Illinois HB 1135, 95 General Assembly, Regular Session (IlL 2007); H.B. 5825, 94th Gen. Assem., Reg. Sess. (IL 2006).
[36] Colorado Revised Statutes § 40-2-123(2)(j) (2006); West Virginia SB 631, 78th Leg., Regular Session (WV 2007).
[37] Illinois Public Acts 92-0012 and 93-0167.

FEED costs, which are difficult for companies to finance through other means, the state avoids one of the major hurdles to undertaking a project and provides an early demonstration of support for a project.

- Indiana provides a tax credit to newly constructed IGCC plants that serve Indiana customers. The Indiana PUC also provides financial incentives to low-carbon coal technology in general, including cost recovery and an increase in shareholder returns while allowing rate changes to be made without a full rate case (see section IV, B).

- Idaho has adopted a moratorium on coal plants other than IGCC.

4. Efforts to advance acceptance of sequestration:

- The West Coast Regional Carbon Sequestration Partnership is engaging in a public outreach process to educate local stakeholders about its geologic sequestration test site.[38] Public concerns generally center on the health impacts and liability for any catastrophic release of CO_2. Acceptance of CCS by the public will be a critical determinant of the viability of this approach to address GHG emissions, so public education and outreach efforts by states are an important component to moving the nation towards a national CCS policy.

- The West Coast Regional Carbon Sequestration Partnership's demonstration project in Solano County, California will provide critical experience in developing siting criteria and procedures.

C. STATE INITIATIVES ON CO_2 TRANSPORT AND DISPOSAL

Despite the incentives and lower risks for CCS that could be provided by some of the mechanisms noted above, the high costs and lack of comprehensive regulatory regimes for the capture, transport, injection and monitoring of carbon dioxide still pose barriers to large-scale CCS deployment. Current federal and state rules pertain to transport and injection of CO_2 for enhanced oil recovery and CCS pilot projects. Currently, non-EOR injection of CO_2 is governed by EPA's Class V Experimental Technology Well Guidance for Pilot Geologic Sequestration Projects.

The Interstate Oil and Gas Compact Commission (IOGCC) has produced a regulatory framework for state regulation of geologic carbon sequestration and provides a template for individual states to proceed with their own rules. The IOGCC regulatory framework would apply to anyone holding a Certificate of Public Notice (CPN) and would regulate "injecting, storing or distributing CO_2 by means of pipelines into, within or through this state for …storage for the purpose of greenhouse gas mitigation."[39] The regulations would declare CO_2 storage to be in the public interest, allow for eminent domain, and require a certificate of closure at the end of injection operations.[40] Ownership and liability issues would be dealt with under the state's property code.[41] North Dakota and Wyoming have released draft rules based on the IOGCC framework and other states are in the process of drafting their own rules. One difference in the two sets of rules released to date involves

[38] For more information and updates, see http://www.westcarb.org/outreach.htm

[39] See Interstate Oil and Gas Commission Compact, "Carbon Capture and Storage: A Regulatory Framework for the States." (2005) [hereinafter IOGCC Framework]:.p. 75. Available online at http://www.iogcc.state.ok.us/PDFS/CarbonCaptureandStorageReportandSummary.pdf . Accessed 12/11/07.

[40] IOGCC Framework p. 75-76.

[41] IOGCC Framework p. 74.

the potential granting of carbon capture and geologic storage permits to CO_2 EOR projects: Wyoming's provisions indirectly disallow this possibility while the North Dakota rules allow it.

A number of states have begun to introduce legislation or form commissions to establish rules and regulations pertaining to disposal of CO_2.[42] Jurisdiction over these efforts will vary from state to state, although significant public utility commission involvement is likely. PUCs will most often establish the siting, financing, and rate recovery rules for the generating facilities producing the CO_2, and may also have some jurisdiction over pipelines that will carry captured CO_2,[43] as well as authority over injection and the financial consequences of any leakage.

In order to expedite the CCS process, an agency or board that coordinates the review of CO_2 disposal sites by all interested state, federal and local agencies streamlines the process (a one-stop siting agency). Such an agency may have jurisdiction to conduct joint hearings and issue joint decisions,[44] exclude projects from other state or local rules[45] and expedite review.[46] Such a siting agency could further hasten deployment by simultaneously accepting and considering applications for the siting of the plant and any associated pipeline or other infrastructure needed for sequestration.

1. "One-stop" Agencies

- The Ohio Power Siting Board ("OPSB") provides the most developed model of a state-level one-stop siting agency.[47] The OPSB provides coordinated review for sites of CO_2 disposal. It engages applicants in extensive pre-review consultation, and is required to issue decisions on coal research and development facilities within 90 days after the application and supporting information is received.[48]

- New York's Advanced Clean Coal Power Plant Initiative created a "Shovel-Ready Team" that serves essentially the same functions as the OPSB, but goes further by assessing particular sites within the state.[49] The team conducted detailed evaluations of over 120 CO_2 disposal sites, choosing 25 "pre-qualified" sites and finally winnowing the field down to the most desirable locations (based on site geology and other factors) for building a coal plant with CCS. Such an endeavor may be a more resource-intensive process than a state agency could or should undertake; however, it certainly provides a powerful tool for expediting clean coal projects.

---

[42] Montana: HB 218 and 282, 60th Leg., Reg. Sess. (MT 2007) (legislation introduced to require establishment of regulations); Kansas: HB 2419, Reg. Sess. (KS 2007) (same); West Virginia: S.C.R. 54, 78th Leg., Reg. Sess. (WV 2007) (resolution to study geologic sequestration and necessary rules and regulations); California: AB 705, Reg. Sess. (CA 2007) (legislation introduced to require establishment of regulations); New Mexico: In New Mexico, Governor Richardson tasked the Oil Conservation Division of the Energy, Minerals, and Natural Resources Department, to facilitate a working group that will propose regulations for geologic sequestration

[43] Jurisdiction over pipeline siting, management, and rates is split between federal and state authorities.

[44] See Ohio Revised Code Ann. § 4906.14 (2005).

[45] See Ohio Rev. Code Ann. § 4906.13 (2005).

[46] See Ohio Rev. Code Ann. § 4906.03(E) (2005).

[47] The OPSB coordinates the action of the Ohio Public Utilities Commission, the Ohio Environmental Protection Agency, the Ohio Department of Health, the Ohio Department of Development, the Ohio Department of Natural Resources, the Ohio Department of Agriculture, and, in some cases, the Ohio Department of Transportation, the Ohio Historical Society, and the U.S. Fish and Wildlife Service. The OPSB issues Certificates of Environmental Compatibility and Public Need.

[48] See Ohio Rev. Code Ann. § 4906.03(E). In all other circumstances, the board has eighteen (18) months to render a decision.

[49] Initiative by the Governor's Office of Regulatory Reform at www.gorr.state.ny.us/ACCPPI-welcome.html.

- Washington State has created an Energy Facility Siting Council with powers similar to those of the OPSB,[50] and Montana[51] and Kentucky[52] have proposed similar agencies.

2. Comprehensive CO_2 Disposal Legislation

- Montana has proposed legislation that would rest authority for regulation of geologic carbon sequestration with the state's Board of Environmental Review.[53] Through House Bills 218 and 282, Montana would establish a system for the permitting, siting, monitoring and verification, mitigation of leaks, restoration of surface land and bonding to ensure the effectiveness of the sequestration.[54]

- The Kansas legislature, under House bill 2419, has proposed regulating carbon sequestration through the authority of the Kansas Corporation Commission.[55] Along with allowing for property tax exemptions and accelerated depreciation, this bill requires the adoption of regulations for the injection and maintenance of carbon dioxide. Fees for permitting would be put into a special fund for the commission to use in determining whether to issue permits, investigating complaints and remediating sites.[56]

- Other states considering comprehensive legislation include West Virginia, California, and New Mexico. West Virginia has adopted a resolution providing for study of, inter alia, statutory and regulatory issues relating to geologic carbon sequestration.[57] Proposed legislation in California would place the burden of crafting regulations on the California Environmental Protection Agency, the Division of Oil, Gas, and Geothermal Resources, and the Resources Agency. California Assembly member Jared Huffman introduced AB 705 to require the study of and establishment of rules and standards for the capture, transport, and injection of carbon dioxide and the monitoring and verification and closure of sequestration sites.[58] New Mexico has also convened a stakeholder process to study the creation of a comprehensive framework for carbon capture and sequestration.[59]

- Through one of the cooperative regional initiatives within the Energy Security and Climate Stewardship Platform for the Midwest, Iowa, Michigan, Minnesota, Ohio, Wisconsin, and the Canadian province of Manitoba are working to establish a regional carbon management infrastructure partnership that will include uniform regional model state regulatory framework for CO_2 capture, transport, injection, and storage, based in part on the IOGCC model framework described above.[60]

---

[50] Wash. Revised Code § 80.50.01 et seq. (2001).
[51] *See* Montana HB 405 § 8(2)(a), 60th Leg., Regular Session (MT 2007) (providing the governor with the authority to "create an executive branch permitting facilitation process for clean energy development projects that, to the extent allowed by law, coordinates and synchronizes all requisite agency applications, permits, licenses, orders, and decisions.").
[52] *See* Kentucky SB 196, Reg. Sess. (KY 2007) (amending KY Rev. Stat. Ann. § 224.10-225) (providing that "the secretary of the Environmental and Public Protection Cabinet shall facilitate the permitting of coal-fired electric generation plants or industrial energy facilities . . . by developing procedures for one (1) stop shopping for environmental permits.")
[53] Montana HB 218 and HB 282.
[54] Montana HB 218; HB 282.
[55] Kansas HB 2419 § 2(a)(2).
[56] Kansas HB 2419 § 3.
[57] West Virginia Senate Concurrent Resolution No. 54 (March 8, 2007).
[58] California AB 705.
[59] Interview with Sandra Ely, New Mexico Air Quality Bureau, May 22, 2007.
[60] The Platform is available online at http://www.wisgov.state.wi.us/docview.asp?docid=12495; see page 26 for the infrastructure agreement

3. CO_2 Transportation and Pipeline Initiatives

Most observers have concluded that existing pipeline safety and siting statutes can be easily amended to include carbon dioxide.[61] A few states have taken actions on this front.

- North Dakota statutes pertaining to pipeline carriers explicitly include the transport of carbon dioxide (due to the active Dakota Gasification project that transports carbon dioxide to the Weyburn field for enhanced oil recovery).[62] While North Dakota does not have a comprehensive CCS statute, the state does have one large commercial carbon transport pipeline.

- Indiana's pipeline safety code defines carbon dioxide as a fluid in a supercritical state containing more than 90 percent carbon dioxide and addresses transportation, distribution and storage of CO_2.[63]

- Montana legislation proposes adding carbon dioxide to the list of gases currently regulated by MCA §69-13-101, which would classify pipelines carrying carbon dioxide as common carriers and provide eminent domain authority for their construction.[64]

- Indiana, Kansas, Iowa, Michigan, Minnesota, Ohio, South Dakota, Wisconsin, and the Canadian province of Manitoba have agreed to a number of measures as part of the Energy Security and Climate Stewardship platform for the Midwest, including implementation by 2010 of a regional regulatory framework that addresses liability issues surrounding CO_2 storage and, by 2012, the siting and permitting of a CO_2 transport pipeline in the region. The Platform lays out a menu of policy options members will adopt to work towards these goals.

State legislatures and many state agencies have a number of tools available to encourage the policies and technological advancement outlined above. In the absence of state or federal GHG reduction requirements, state utility commissions will have ultimate responsibility for providing the conditions for the successful completion of low-carbon coal power generation projects. The following section discusses the various steps public utility commissions can take to create these conditions and spur the development and deployment of CCS technology.

[61] IOGCC Framework.
[62] North Dakota NDCC 49-19-01 et seq.
[63] Indiana IC 8-1-22.5 et seq.
[64] Montana HB 24.

III. Public Utility Commission Policies for Carbon Capture and Storage

Because electric power is an essential public service, the power sector is closely regulated under public utility laws in every state and many of the financial and regulatory tools that can be used to advance CCS are available to, and fall within the jurisdiction of, public utility commissions (PUCs). Public utility regulators are expected to balance multiple, often-competing goals: to protect ratepayers, to ensure the continuation of adequate and reliable electric power service, to support the long-term financial stability of generators and utilities and, increasingly, to transform the power generation sector to lower GHG emissions and meet society's needs for long-term environmental health.

While the public policy imperatives driving advanced coal and CCS technologies are persuasive, there are many barriers to the near-term deployment of CCS projects embedded in longstanding utility regulatory practices and policies in the United States. It is important to understand that some of these barriers are based on the well-founded reluctance of ratepayer advocates and public utility commissions to grant financial incentives to, or shift risk from, developers of CCS projects. This reluctance is based on almost a century of regulatory experience seeking to find a proper balance between ratepayer protection and incentives to utility investors. On the side of caution, regulatory commissions are aware of utility financial excesses and rich shareholder benefits going back to the railroad era, and the rate impacts of both nuclear plant cost overruns and power market manipulations of just a few years ago. On the side of assisting utilities, regulatory commissions increasingly share the public's desire for environmentally sustainable energy policies, and are coming to terms with the urgent need to turn the corner quickly on the future of coal generation in the United States. Yet a further potential barrier to widespread deployment of CCS is the current lack of public understanding and acceptance of the technology.

The result is that efforts to promote CCS projects through the policies of public utility commissions must be crafted carefully to provide an acceptable balance among competing objectives, and cannot simply be removing "regulatory barriers" to CCS that reside in longstanding regulatory and ratemaking practices. CCS strategies must also account for the operation of wholesale power markets and the structure of the power sector, both of which have changed dramatically in the last decade. Many of the barriers to CCS experimentation and early CCS deployment arise in these new power markets. For example, independent power producers, a large and growing segment of the power industry, can not be expected to develop CCS projects on a speculative basis. So long as conventional coal generation enjoys a substantial cost advantage over generation with CCS, it will be chosen by utilities in the absence of policy intervention.

The PUCs of a number of states have already taken steps to expedite CCS's commercialization, either by establishing strict emissions standards or by providing financial and regulatory incentives, or in some cases, both. Others have encouraged IGCC, considered by some to be the most promising platform for CCS (although whether it indeed has a substantial advantage over advanced technology pulverized coal ("PC") plants as a platform for CCS has not been determined). This section examines existing and proposed regulatory tools available to PUCs to advance CCS. The main avenues that PUCs have explored to support CCS can be considered as falling into five groups:

A. Considering costs of carbon constraints during planning;

B. Financial assistance through Cost Recovery provisions

C. Other financial assistance mechanisms

D. Waivers from standard review-process requirements

E. Power acquisition agreements and other utility-specific options

The subsections below provide brief reviews of state initiatives in each of these categories.

A. CONSIDERING CARBON CONSTRAINT COSTS DURING PLANNING

According to the National Energy Technology Laboratory, there are as many as 151 new coal-fired plants, with a total capacity of 96GW, now proposed to be built in the United States alone.[65] Yet on October 18th, 2007, Secretary of the Kansas Department of Health and Environment Roderick Bremby rejected an air permit for a proposed coal-fired power plant based on the threat to public health and the environment posed by carbon dioxide emissions. In the past, air permits have been denied over emissions such as sulfur dioxide, nitrogen oxides, and mercury, but this marks the first rejection based on impacts from carbon dioxide emissions. The decision was based in part on an April Supreme Court decision that greenhouse gasses should be considered pollutants under the Clean Air Act. The plant was expected to produce 11 million tons of carbon dioxide annually.

Consensus is growing that carbon regulations including emission caps will be enacted by Congress in the next few years. However there is tremendous uncertainty regarding the stringency of these rules and how existing and new coal plants will be treated. Some coal developers, expecting that future cap-and-trade regimes will allocate greenhouse gas emission allowances to existing plants on a grandfathered basis for free, are rushing to get their plants built in a "race to grandfather." Other developers, particularly in the face of the Kansas decision, are reluctant to pursue coal plants. One way to deal with these uncertainties is for utility regulators to adopt procedures that provide warnings and information about the risks of new builds of coal plants without CCS. The two forms such approaches take are carbon adders for use in utility resource planning, and cost-recovery policies and warnings, advising investors that future carbon compliance costs for new coal plants without CCS may not be passed on to ratepayers.

[65] National Energy Technology Laboratory, Tracking New Coal-Fired Power Plant: Coal's Resurgence in Electric Power Generation 4 (May 2007) [hereinafter NETL, Coal's Resurgence].

1. Carbon Adders

A few states require utilities to consider the cost of compliance with carbon constraints in their resource planning.[66] Whether quantitative "carbon adders" or qualitative analyses are specified, such requirements force utilities to consider the potential effects of carbon dioxide regulation in their current investment decisions. Such considerations affect the determination of what qualifies as a least cost resource, as important issue in PUC decisions. California instituted carbon adders in 2004,[67] and Oregon's PUC requires utilities to consider a range of possible CO_2 costs in their resource plans. The Arkansas commission has taken a qualitative approach, recently requiring Southwestern Electric Power Company to submit testimony regarding the potential effects of climate change regulation, as well as alternatives to its proposed coal-fired generation plant including demand side responses, efficiency, and clean coal technology (IGCC and CCS).[68]

Recently parties have questioned whether utilities are underestimating the costs of adding CCS,[69] and Oregon has opened a proceeding to on the issue.[70] The New Mexico commission has opened an inquiry into the possibility of setting "standardized carbon emissions costs."[71]

2. Traditional Jurisprudence

One of the most powerful mechanisms to ensure that new investments in coal-fired generation are designed to minimize costs of adding or including CCS is the application of traditional utility prudence standards. Significant GHG regulation is anticipated within the next few years, and certainly within the economic lifetimes of any new coal plants. Such regulations will result in additional costs for the operation of coal-fueled facilities. Utility regulators will be asked by plant owners to pass these new costs on to ratepayers, but they will be asked by consumer advocates, including advocates for industrial customers, to require plant owners to assume these costs as a condition of continued operation.

Under traditional utility regulatory jurisprudence, a utility's failure to consider explicitly the economic risk of future regulation before committing ratepayers to investments in a major plant would likely be grounds for a PUC finding of imprudence on the part of the utility. In such a case, cost recovery could be denied, with losses to shareholders. To avoid this situation in the case of CCS, utility regulators, consumer advocates, and other stakeholders could require utility managers and investors to take expected legislation restricting CO_2 emissions into account in considering and planning major commitments to new coal plants. An explicit warning could take the form of a formal statement by the state legislature, regulatory commission, attorney general, or public advocate that future GHG compliance costs will not be included in rates unless the utility has demonstrated that it has taken all reasonable steps to consider the least cost approach taking all low-emitting options into account, including energy efficiency, renewable energy, and coal with CCS.[72]

---

[66] The Wisconsin PUC had initiated an "Advance Plan docket" in 1992 that required utilities to add the cost of $15/ton for carbon dioxide emissions in its procurement selection process, but this was later abandoned. In its 2006 IGCC Report it recommended reinstituting some sort of carbon adder. IGCC Draft Report at 54.
[67] See California R. 04-04-025; D. 05-04-024.
[68] Arkansas Public Service Commission, Docket No. 06-154-U, Order No. 5 (March 2, 2007).
[69] Pacificorp used a range from $8/ton CO_2 to $30.80/ton CO2. Order No. 07-018 at 9.
[70] See id. (referring to Order No. 07-002 (Docket UM 1056)).
[71] Case No. 06-00448-UT (October 31, 2006).
[72] See e.g., Michael Dworkin et al., Coal-Fired Power Plants: Imprudent Investments?, 315 Science 1791 (March 2007).

B. FINANCIAL ASSISTANCE THROUGH COST RECOVERY

Industry and environmental leaders recognize that achieving deployment of clean coal technology may require both mandatory emissions standards and financial incentives.[73] In this subsection we focus on policies to pro-actively support CCS, develop demonstration projects, and encourage the power industry to deploy advanced coal resources through cost recovery guarantees. As PUCs consider use of cost-recovery, they will need to strike the fine balance between acknowledging the financial risks and difficulties faced by power producers, the need to protect ratepayers from cost overruns such as those seen during past nuclear plant construction, and the need to prepare for stringent carbon constraints.

The single most important incentive for power producers to undertake investments in new technology is the guarantee of cost recovery. In today's power markets and regulatory regimes, this is an even more difficult problem for new technology than it has been historically. In large portions of the nation, the restructuring movement of the 1990's broke up large, vertically-integrated utility systems, and created independent power producers who must rely on competitive wholesale markets for cost recovery, rather than securing cost recovery for their investment from captive customers via rates set by their PUCs.[74] Even in states that did not restructure, utilities and merchant generators are still recovering from the precipitous decline of their credit ratings due to the Western power crisis of 2001, which threatened the financial viability of a number of utilities, the collapse of Enron, and the large number of natural gas plants forced into receivership by high gas prices. On a more long-term basis, painful memories still linger from the billions of dollars invested, but whose cost recovery was disallowed by PUCs, in the nuclear plant cases of the 1980s and 1990s.

In addition to the problem of recovering the costs to build and operate plants with CCS, the high up-front price-tags for design and development studies can present problems. Under some ratemaking practices these costs may not be recoverable in rates unless linked to specific projects that are later included in rate base.[75] A second cost issue is that traditional ratemaking considerations, such as low cost and reliability, tend not to support use of an undemonstrated technology such as CCS. To address all of these cost issues, a few states have implemented or proposed a number of measures, as reviewed below:

1. Timely Recovery Provisions.

Several states have added "timely recovery" provisions to their utility regulatory statutes.[76] These provisions often do not specify exactly what is meant by the term "timely recovery," but the intentions of the provisions can be met in a variety of ways. Specific utility regulatory mechanisms to provide timely cost recovery by CCS investors include:

a) Recovery of Construction Work in Progress (CWIP). Traditional utility ratemaking policy provides that a company's investments in utility assets should not be included in rates until the asset in question is "used and useful" for the provision of regulated utility services—that is, ratepayers should not be required to pay for it until

[73] United States Climate Action Partnership, A Call for Action (January 2007).

[74] That is, under a franchise system, vertically-integrated utilities recovered their costs through rates established by the public utilities commission. In a restructured setting, rates depend not upon regulatory review, but upon the market.

[75] The front-end engineering and design study may cost between $10 and $25 million because there is no experience with the commercial demonstration of the technology. Interviews with Marty Smith (Xcel Energy) and Sandra Ely (New Mexico Dept. of Environmental Quality).

[76] Many states have proposed or allowed what they refer to as "timely recovery." In some cases this means CWIP recovery in other cases it refers to the use of rate adjustment clauses.

it is providing them service. This policy protects ratepayers from the kind of cost overruns, plant cancellations and delays that plagued nuclear construction in past decades, but imposes significant financing costs and risks on utility investors, particularly for large-scale, complex, or innovative technologies. One technique for shifting these costs and risks to ratepayers is Construction Work in Progress (CWIP), which allows the utility to roll ongoing project costs into rates before the facility is operational. Debate over this mechanism was fierce during the nuclear plant construction era, with consumer and environmental advocates often opposing CWIP. Many of the same arguments against CWIP are raised today in regard to CCS, but the political dynamics may be different. Environmental advocates may be less opposed to CWIP for CCS than for nuclear facilities. However, others may object to using CWIP for CCS because it could set a precedent for using it for other technologies.

b) Avoiding across-the-board reviews. Ratepayer advocates usually oppose adding major new costs to rates without an across-the-board rate case, since across-the-board rate cases provide an opportunity to examine the utility's entire operation, including the quality of service provided and cost elements that may have gone down since the last general review. Advocates of timely recovery for CCS investments on the other hand may prefer a regulatory practice that would allow their project costs to be recovered without undergoing an across-the board review, which can be time-consuming. Mechanisms that could be used to flow CCS costs into rates without a general rate review include fuel adjustment clauses,[77] capacity recovery clauses,[78] retail rate adjustment clauses,[79] or CCS-specific rate adjustment clause.[80] Since deployment of CCS significantly increases fuel requirements and reduces net output, use of fuel adjustment and capacity recovery provisions seem appropriate and promising avenues for avoiding across-the-board rate reviews. On the other hand, it is hard to view CCS capital costs and entirely new generation costs as simply a change in the cost of fuel that is outside the ability of the utility to manage.

2. Preapproval of Cost Recovery. This is one model that provides a great deal of certainty for CCS cost recovery and significantly reduces risks to CCS investors, but increases risks to ratepayers. It would permit the regulatory preapproval of CCS projects and exempt those projects from challenges on the basis of "excessive cost, inadequate quality control, or inability to employ the technology,"[81] thus ensuring cost recovery through appropriate rates. States where decisions allowing preapproval of costs have been made or proposed include Illinois, Indiana, and Ohio. Indiana has limited preapproval to utilities that apply to the Commission for ongoing review of construction costs, and the application must undergo public hearing before approval.[82]

---

[77] A fuel adjustment clause provides for rate increases or decreases due to changes in the utility's cost of fuel without resort to a fuel cost-of-service review in a rate case. To the extent that advanced coal processing costs, coal gasification costs, and the like are considered variable fuel costs, recovery through the utility's fuel adjustment clause seems consistent with historic practice. Illinois allows cost recovery of purchases of synfuel through purchased gas adjustment clause. See 220 Illinois Comp. Stat. § 5/9-220(h) (2005). Indiana proposes passing costs of purchasing substitute natural gas (gas produced through gasification) through a fuel adjustment clause. See Indiana HB 1722, 115th Gen. Assem., 1st Reg. Sess. (IN 2007).

[78] Proposed legislation in Florida would allow recovery of preconstruction costs, carrying costs and cancellation costs through a capacity cost recovery clause. See Florida HB 549, 109th Leg. Sess., Reg. Sess. (FL 2007) (introduced in the Senate as SB 1202).

[79] Indiana has enacted and has pending statutes that allow recovery through retail rate adjustment mechanisms based on forecasted or actual costs as long as a reconciliation mechanism is included for forecasted costs. See Indiana Code §§ 8-1-8.8-1 and 8-1-8.8-12 (2002); HB 1713, 115th Gen. Assem., 1st Reg. Sess. (IN 2007); HB 1722, 115th Gen. Assem., 1st Reg. Sess. (IN 2007). Retail rate adjustment clauses may be used to increase rates without a full rate case where current retail rates fail to adequately cover stranded costs, government mandated costs, or various other costs.

[80] Colorado: Colorado Rev. Stat. 40-2-123(2)(f)(I) (2006) created a separate rate adjustment clause for projects covered by the statute; Ohio: Ohio Admin. Code § 4901:1-12-01 (2006) creates the "Ohio coal research and development cost adjustment." This cost adjustment clause allows for a "provision in a schedule of a gas or natural gas company that requires or allows the company to, without adherence to [a full rate case], recover on a uniform basis per unit of sales of Ohio coal research and development costs, determined to be reasonable by the commission." Id. at § 4901:1-12(c).

[81] Indiana Code 8-1-8.7 (2002).

[82] Id.

3. Expanded Cost Recovery. Some states have expanded the types of costs recoverable from ratepayers. For example, in 2006, the Ohio PUC issued an order allowing the utility AEP to recover its preconstruction costs for an IGCC plant including the costs for its front-end engineering and design study (see Appendix III for details). The Indiana PUC also approved a settlement providing cost recovery for front-end engineering and design costs under $20 million.[83]

Colorado provides more generous cost recovery, and Florida is considering doing so. In Colorado retail rates can be set to cover not only preconstruction costs (including studies, surveys and permitting costs) but also costs for purchasing electricity in the event of planned and unplanned outages during initial startup and commercial operation, full-life cycle costs for construction and operation, costs incurred up to the time of cancellation of a project, and costs of wholesale contracts until recovered through the Federal Energy Regulatory Commission (FERC).[84] Legislation proposed in Florida would also allow a utility to recover the net book value of any existing plant replaced by an IGCC plant.[85]

A complex, pending question in the area of cost recovery for CCS is whether the costs of CO_2 storage—including transport, injection, storage, monitoring, long-term verification, and future compliance costs—should be recoverable. As a practical matter, PUCs are likely to be much more familiar with, and accepting of, expanding cost recovery to activities that are part of the power plants directly under their regulatory control than they would be with the costs of transport and long-term storage.

C. OTHER FINANCIAL ASSISTANCE MECHANISMS

A number of other mechanisms have been tried or proposed to improve the cost-revenue picture for new power generation technologies. Mechanisms can provide higher rates of return; grant bonding authority; accelerate depreciation; provide flexibility in completion date, capacity, and construction cost agreements; or speed the approval process. To date these have been used to promote other technologies, but they could be used for CCS.

Indiana, for example has enacted a statute allowing "clean coal projects" to earn a rate of return on shareholder equity of up to 3 percentage points more for IGCC plants than would otherwise be allowed,[86] and California's commission may allow "an increase from one-half to 1 percent in the return on investment" for a contract investing in zero- or low-carbon resources.[87] Wisconsin's Public Service Commission has considered whether to allow a rate of return on purchases of power from IGCC plants, limiting such a rate to cover costs of the gasifier portion. Under existing law purchases of power are treated on a "pass-through" basis, and utilities do not earn income from the purchases. Allowing a return rate would thus be an increase over current "zero" return laws.[88] Where the investors' returns are already fairly well secured by cost-recovery mechanisms such as described in this paper, ratepayer advocates are likely to resist allowing higher rates of return. Thus, regulators should consider the tradeoff between offering higher rates of return versus assuring cost recovery.

[83] Re PSI Energy, Inc. dba Duke Energy Indiana, Inc., 251 P.U.R.4th 287, 2006 WL 2547054 (Ind. U.R.C.) (July 26, 2006).
[84] Colorado Rev. Stat. § 40-2-123(f) (2006).
[85] Florida HB 549, 109th Leg., Reg. Sess. (FL 2007) (amending 366.93(4)). Recovery would occur over a period of not more than 5 years. As written, this provision would perhaps more than insulate a utility from the risks of adding an IGCC plant, but would not achieve any carbon capture or storage.
[86] A pending legislative proposal would extend the higher rate to the purchase of synfuel as well. Indiana Code §§ 8-1-8.8-1 and 8-1-8.8-11 (2002). H.B. 1722, 115th Gen. Assem., 1st Reg. Sess. (In 2007).
[87] California Pub. Util. Code § 8341(b)(6) (2007).
[88] The Wisconsin Draft Report noted Indiana's action and suggested that it could do the same by amending its "fixed financial parameters law", Wis. Stat. § 196.371, to include IGCC projects. See Wisconsin Draft Report p. 57.

Authorization of bonding for environmental equipment has been used in Wisconsin and West Virginia. In Wisconsin a utility may apply to the public service commission for a financing order authorizing it to issue "environmental trust bonds" to install environmental control equipment.[89] Issuance of such an order "irrevocably authorize[s] the utility to impose charges upon its ratepayers that are sufficient to recover the costs of the bond issuance, even if the environmental control facilities do no perform as anticipated." Under a similar statute, West Virginia's commission may issue "environmental control bonds" to finance the construction or installation of environmental control equipment. West Virginia covers the costs of this incentive through the imposition of an "environmental control charge" on utility customers.[90]

Depreciation schedules can also be used to provide financial benefits. Indiana allows public or municipal utilities to depreciate clean coal technology over a period of not less than 10 years and not more than 20 years if the facility uses Indiana coal or "is justified" in not using it.[91] Since the typical expected life of coal generation facilities is far longer than 10-20 years, accelerated depreciation provides both an earlier return on the investment and lower risk to the investors that the investment would become a stranded asset.

Another proposal would provide "more flexibility regarding completion dates, the cost of construction, and the plant's anticipated capacity factor,"[92] Such flexibility would relieve power providers from penalties for over-runs. Under this proposal, cost recovery could also be granted even if the plant did not reach its estimated level of power production.[93]

Expediting any portion of the review process decreases costs for the applicant[94] and a number of mechanisms are in use or under consideration. Applications for a Certificate of Public Convenience and Necessity (CPCN) are required in many states in order to site a new power plant. Strict time limits for determinations of certificates of public need have been proposed in Florida and Indiana. Florida's House Bill 549 would require decision on a CPN within 135 days from filing,[95] and Indiana's House Bill 1713 would require a CPN determination within 120 of the application unless the applicant had not cooperated fully.[96] To speed cost recovery decisions, Indiana law requires a determination of eligibility within 120 days of the application,[97] and North Dakota requires decisions on applications for an advance prudence determination—which, if granted, is "binding for ratemaking purposes"[98]—within seven months.[99]

[89] Wisconsin Stat. § 196.027 (2006).
[90] West Virginia Code R. § 24-2-4(e) (2006).
[91] Indiana Code § 8-1-2-6.7 (2002) (defining clean coal technology as "a technology (including precombustion treatment of coal) . . . that is used at a new or existing electric generating facility and directly or indirectly reduces airborne emissions of sulfur or nitrogen based pollutants associated with the combustion or use of coal; and . . . that either: . . . is not in general commercial use at the same or greater scale in new or existing facilities in the United States as of January 1, 1989; or . . . has been selected by the United States Department of Energy for funding under its Innovative Clean Coal Technology program and is finally approved for such funding on or after January 1, 1989.)
[92] Wisconsin Draft Report at 58.
[93] See id.
[94] At least in the short term. On the other hand, a more deliberative review may uncover potential pitfalls in the project, or more favorable alternatives that should be considered before large financial commitments are made.
[95] Florida HB 549, 109th Leg., Reg. Sess. (FL 2007).
[96] Indiana HB 1713, 115th Gen. Assem., Reg. Sess. (IN 2007).
[97] Indiana Code 8-1-8.8-1 (2002)
[98] Id. at § 49-05-16(4) (2005). It should be noted that provisions for in-advance prudence review, or "rolling prudence" reviews are quite controversial in the field of utility regulation. Opponents assert that they go too far in shifting the risk of construction failures and poor performance to ratepayers, who have no control over the construction and operation of the relevant facilities, and away from utility managers, who do have that control.
[99] See id. at § 49-05-16(2) (2005).

Delays and duplicative efforts also often plague the siting review process, and a number of approaches other than one-stop shopping have been proposed. In some locations it may be possible for state siting boards or PUCs to use their powers of preemption to alleviate delays inherent in obtaining local zoning or development permissions. A proposal in Montana, for example, would exempt clean energy projects from any "unreasonably restrictive" local laws or regulations.[100] CPCN applications generally require information on multiple siting alternatives. In its report on IGCC, Wisconsin proposed the idea of allowing an applicant to provide detailed analysis only of its preferred site along with information on the site evaluation process and limited information about alternative sties. A Montana proposal would exempt certain projects from the environmental impact statement requirement when a state agency issues any permit or other approval, and Kentucky's Senate Bill 196 would limit the time allowed to reach environmental permitting decisions. However, such expedited reviews could work against public acceptance of CCS.

D. WAIVERS FROM CPCNS AND COMPETITIVE BIDDING REQUIREMENTS

Some of the most controversial challenges for both regulators and regulated utilities involve the initial decisions whether to approve proposed major power plants. In the case of regulated, vertically-integrated utilities, many states also now require the CPCN applicant to meet requirements such as congruence with the utility's integrated resource plan or satisfaction of least cost resource or competitive acquisition standards. Applying these prerequisites to projects planning to use CCS presents a difficulty: justifying the additional costs of a technology whose reliability has not been proven in the absence of any state or federal mandates requiring its use. States have begun to address these obstacles with legislation that changes how the public utilities commissions evaluate clean coal technologies.

Minnesota is the only state that waives the requirement for a certificate of public convenience for innovative projects.[101] Proposed legislation in Montana may exempt "clean energy projects," including coal gasification, by proclaiming that such projects are "considered to serve the public interest, convenience, and necessity."[102] Colorado allows IGCC projects agreeing to capture and sequester a portion of their carbon dioxide emissions to apply for a waiver of the state's competitive resource acquisition mandate which requires the utility to choose the "least-cost resource."[103] A Florida proposal would also exempt an IGCC project applicant from the requirement to "secure competitive proposals for power supply."[104] Finally, one report suggested exempting IGCC plants from a 2003 Wisconsin law that limited new generating facilities to brownfield sites.[105]

E. POWER ACQUISITION AGREEMENTS AND OTHER UTILITY-SPECIFIC OPTIONS

One of the most important roles of public utilities, and thus of PUCs, is the development of a portfolio of resources to serve long-term customer power demand. Two key tools that have been developed to meet this

---

[100] See Montana HB 405(4)(c), 60th Leg., Reg. Sess. (MT 2006). A project approved by Ohio's Power siting board is also exempt from local regulations.
[101] See Minnesota Stat. 216B.1694 (2006)."An innovative energy project . . . is exempted from the requirements for a certificate of need."
[102] Montana 60th Legislature, House Bill No. 405, Section 4(1)(A)(d).
[103] See Colorado Rev. Stat. § 40-2-123(2)(e)(1) (2006). If the commission approves the certificate of public need after waiving this requirement, the statute requires the commission to issue a declaratory order for cost recovery.
[104] Florida HB 549, 109th Leg., Reg. Sess. (Fl. 2007) (amending 403.519(4)(c)).
[105] See id. (recommending amendment to Wisconsin Stat. §§ 196.49(4) and 196.491(3)(d)8) (2006).

objective and that are, or could be, used to accelerate deployment of CCS technologies are guaranteed power purchases and loading order guidance.

In Minnesota, the Clean Energy Technology Act requires a utility that owns a nuclear plant to buy at least 2 percent of its energy for retail customers from an "innovative energy project."[106] New York's Advanced Clean Coal Power Plant Initiative guarantees that the New York Power Authority will purchase power from the developer chosen to construct an advanced coal plant with CCS.[107] Since proof of a stable revenue stream is essential to obtaining financing for a power plant, guarantees of power purchase can make CCS plants happen.

Some states, led by California, have established a set of preferences or a "loading order" for utilities to follow in selecting new resources in their integrated resource plans for their portfolios. Alternatively, CCS could be listed as a preferred resource in a state's general loading order, which guides planning and procurement decisions. For example, the Wisconsin Commission has considered ranking IGCC with CCS above other coal alternatives or giving it the same priority as renewable resources in its ranking of generating options.[108]

The above review reveals a large number of potential regulatory and market policies that could be used to advance CCS in the United States through the work of public utility commissions. Some of these policies are in effect in various states; many more have only been proposed; and very few have actually had much effect in these early stages of the development of a CCS industry. The 25-plus policies reviewed above cover a range of intervention points and methods, including (a) utility planning and power acquisition activities; (b) project development costs and siting procedures; (c) long-term and short-term cost recovery and rate-making policies; and (d) supporting policies in areas as diverse as eminent domain and risk management for future releases. Before any given policy is applied, however, regulators must consider carefully its pros and cons; how much special treatment to provide CCS projects; whether the benefits of the projects justify this treatment; under what circumstances CCS projects in particular, rather than other forms of electricity generation, should qualify for certain policies and incentives; and ultimately, how to advance CCS without making the nascent industry overly dependent on regulatory incentives. To help regulators work towards these (sometimes competing) objectives, each policy that might advance CCS should be evaluated across a range of criteria, including:

1) **Acceleration**: Will it produce investment in CCS that would not otherwise occur?

2) **Deterrence**: Will it deter unsound investment in high-emitting technology options, given the likelihood of future national-level carbon policy?

3) **Prudence and Accountability**: Will it promote prudent project management by those in a position to lower costs, improve reliability, and increase the rate of attainment? Will project managers be held accountable for financial and environmental results?

4) **Power supply costs**: Does it contribute to lower costs of CCS power generation?

[106] Minnesota Stat. § 216B.1693(a) (2006).
Minnesota Stat. § 216B.1694.
[107] New York Advanced Clean Coal Power Plant Initiative, www.gorr.state.ny.us/ACCPPI-welcome.html .
[108] Wisconsin Draft Report 56 (recommending a change to Wisconsin Stat. § 1.12 (2006)).

5) **Administrative costs**: What are the impacts on administrative and regulatory costs for developers, government, and other parties?

6) **Risk and cost balance**: How well does it balance the interests of ratepayers and investors? How can regulators make sure risk is properly allocated? Should ratepayers and investors share risks more equally if doing so can drive low-carbon innovation? How does an option transfer risk? Is the risk transfer adequately compensated, e.g. sufficiently lower ROI on pre-approved projects?

7) **Innovation**: Will it promote further CCS research and technical innovation?

8) **Standards:** Will it promote CCS projects and technologies that would be able to be replicated elsewhere, including measurement and verification?

9) **Performance:** Are the incentives scaled to real world performance, measured especially in tons of CO_2 permanently sequestered?

IV. Conclusion

In the absence of federal leadership on climate change, many states are taking actions to reduce their greenhouse gas emissions. States recognize that coal power is one of their largest sources of carbon dioxide emissions and one likely to remain in widespread use for decades. As such, any effort to seriously address climate change must also address carbon emissions from coal power, and permanent Carbon Capture and Storage (CCS) is the critical technology for doing so. Many states have put incentives in place to advance coal technology broadly, and a small but growing number of states are specifically focusing on CCS.

This paper has surveyed many of the policy tools available to states as they seek to encourage the deployment of carbon capture and sequestration, and highlighted key lessons drawn from state experience. In addition to policies being pursued in these and other states, some promising avenues for the advancement of CCS include:

1) Setting generator performance standards that can drive low-carbon coal power, as in Montana, Oregon, and Washington;

2) Establishing retailer standards which operate in a manner analogous to the renewable portfolio standards that many states already use. California has adopted a GHG performance standards for new long-term power procurements that applies to retailers in its programs under SB 1368.

3) Cap and trade programs for greenhouse gases such as those being established by the Regional Greenhouse Gas Initiative, the Western Climate Initiative, and the Midwestern Regional Greenhouse Gas Reduction Accord;

4) Feebates, through which individual plants would be subject to a fee, and the funds generated would be used to deploy CCS technology at upgraded or newly built units;

5) Using a combined policy approach in which one or more of the above policies are implemented simultaneously.

Within the realm of Public Utility Commissions, there is insufficient experience with, and insufficient comparative analysis of, the more than 25 PUC policies in practice in the United States that were reviewed in Chapter IV to recommend any of them as "best practices" for utility commissions or legislatures. Rather, the authors recommend additional analysis of the more promising approaches, and discussions with the regulatory community and affected stakeholders (chiefly, utilities, developers, ratepayer advocates, and environmental experts). The challenge is to identify the mixture of policies that would seem to do the best job of supporting accelerated development of CCS within the electricity markets and regulatory contexts governing the U.S. power sector while safeguarding ratepayer interests and leading to a viable, stand-alone industry in the United States. Appendix IIc features a table with preliminary rankings for the various policy options available to PUCs on their relative effectiveness in promoting CCS. Some of the PUC tools that show particular promise and should undergo further analysis include: (a) utility planning and power acquisition activities; (b) project development costs and siting procedures; (c) long-term and short-term cost recovery and ratemaking policies; and (d) supporting policies in areas as diverse as eminent domain and risk management for future releases. It is important to recognize that CCS policies cannot be judged solely by whether they are likely to result in maximum or most rapid deployment of CCS facilities. As with other low-GHG options, such as photovoltaic generation or ethanol production, a variety of competing and complementary goals must be considered. Regulators and other policy-makers value not only rapid deployment of CCS, but also overall cost-effectiveness, driving down cost curves over time, and an equitable balancing of risks between consumers and investors. States have a critical role in the commercialization of CCS technologies and many tools with which to accomplish this vital goal. Implementation of such tools will assist both states and the nation in addressing the emissions from coal-fueled plants.

Although national policy is essential, a proactive approach by state policymakers and regulators to drive CCS can reduce future compliance costs, speed the required technological developments, and pave the way for future national policy. Regardless of the final form of federal greenhouse gas regulations, states have both the authorities and the opportunities to gain experience as first movers and policy innovators, and will play an important role in shaping a low-carbon future.

Appendix I: Current State and Regional Coal Initiatives

ARIZONA

Existing Regulations and Policies Relevant to CCS

Executive Order 2006-13
On September 8, 2006, Arizona Governor Janet Napolitano issued Executive Order 2006-13, which established a statewide goal to reduce Arizona's GHG emissions to 2000 levels by 2020, and 50 percent below 2000 levels by 2040.

Arizona is also a member of the Western Climate Initiative (see below).

ARKANSAS

Existing Regulations and Policies Relevant to CCS

Arkansas PSC Docket No. 06-154-U, Order No. 5 (March 2, 2007)
In reviewing an application for a certificate of environmental compatibility and public need for the construction, ownership, operation and maintenance of a coal-fired baseload generating facility, the Arkansas Public Service Commission ordered the applicant to file supplemental testimony regarding, inter alia, why it chose to apply for a coal-fired plant in the face of impending federal regulation of greenhouse gas emissions, whether it had calculated the potential costs for different legislative scenarios, and whether it had considered other options such as IGCC.

CALIFORNIA

Existing Regulations and Policies Relevant to CCS

AB 32
Sets a state-wide greenhouse gas emissions cap of 1990 levels by 2020, and represents the first enforceable state-wide program in the U.S. to cap all GHG emissions from major industries that includes penalties for non-compliance. The law requires the State Air Resources Board to establish a program for statewide greenhouse gas emissions reporting and to monitor and enforce compliance with this program. It also authorizes the state board to adopt market-based compliance mechanisms including cap-and-trade, and allows a one-year extension of the targets under extraordinary circumstances.

AB 1368
Requires the public utilities commission, in consultation with the State Air Resources Board and Energy Commission, to establish an emissions performance standard for procurement of baseload generation by load-serving entities. The law set forth the following requirements:

- Long-term financial commitments[109] by load-serving entities or publicly owned electric utilities to purchase baseload generation shall comply with the greenhouse gases emissions performance standard that does not exceed the emissions from a combined cycle natural gas baseload generation plant.
- The public utilities commission may review any proposed long-term financial commitments and shall enforce compliance with the emissions performance standard.
- The public utilities commission shall adopt procedures for load-serving entities to calculate and verify emissions and emissions reductions.

The law also provides the following incentives:

- Timely cost recovery by treating compliance costs as procurements costs incurred pursuant to an approved procurement plan.
- An increase on the return on investment of one-half to 1 percent for the party "entering into the contract with an electrical corporation" that meets the emissions performance standard.

Failure to comply constitutes a crime.

PUC Decision No. 07-01-39
- Established an interim emissions performance standard for baseload generation of no more than the greenhouse gases emitted from a combined cycle natural gas plant.
- Applies to:
  - Load-serving entities
  - Entering long-term financial commitments (new ownership investments or renewal or entrance into power purchase agreements of 5 years or more)
  - Baseload generation (operating at 60% capacity factor)
- Not a portfolio standard; each and every new long-term power contract must meet the standard.

Proposed Regulations and Policies Relevant to CCS

AB 705
Purpose is to develop a framework to advance cost-effective geological sequestration of carbon dioxide.

- Requires cooperation among the Division of Oil, Gas, and Geothermal Resources, the California Environmental Protection Agency, and the Resources Agency to develop standards and regulations for the injection and storage of carbon dioxide.

[109] Long-term financial commitments are defined as "either a new ownership investment in baseload generation or a new or renewed contract with a term of five or more years." § 8340(j).

- The Division of Oil, Gas and Geothermal Resources would develop regulations relating to the siting, drilling, monitoring, mitigation of adverse effects, determination of subsurface rights, and closure of a storage site.
- California EPA would be responsible for determining (in collaboration with the EPA) the required composition of the carbon dioxide injected, testing, monitoring, and verification from capture to storage, and procedures for closure of the site.
- The Resources Agency would establish regulations for liability and indemnification.

COLORADO

Existing Regulations and Policies Relevant to CCS

Colo. Rev. Stat. § 40-2-123 et seq. (2006)

- Declares supporting deployment of IGCC with CCS that uses western coal is in the public interest.
- Requires commission to give "fullest" consideration to clean energy and efficiency technologies in determining generation acquisitions.
- Limits incentives to power plants:
  - Employing IGCC technology
  - Using Colorado or western coal
  - Not exceeding 350 MW
  - Capturing and sequestering a "portion" of emissions
  - Monitoring the sequestered carbon dioxide and
  - Operating in Colorado

- Provides the following incentives:
  - Waiver of competitive resource acquisition requirement under CPN determination
  - Issuance of declaratory order for cost recovery upon approval of CPN
  - Current recovery of the utility's weighted average cost of capital through a separate rate adjustment clause
  - Assignment to retail ratepayers of a portion of unrecovered costs from wholesale contracts until utility receives recovery from FERC if the utility applies for recovery within six months of assignment and makes a good faith effort to secure recovery from the wholesale customers.
  - Recovery of:
    - Full life-cycle capital and operating costs
    - Power purchases resulting from planned and unplanned outages during and after initial startup and testing
    - Prudent costs associated with shutdown, decommissioning, or repowering
  - Authorization as component of resource plan upon specified conditions
  - Support in obtaining federal funding
  - Financial support for study, engineering and development from the clean energy development fund

Allowance of the creation by one or more public utilities of a special purpose entity to develop, construct, or own an IGCC facility under this statute.

CONNECTICUT

Existing Regulations and Policies Relevant to CCS

On August 26, 2001, Connecticut Governor John Rowland signed onto The Climate Change Action Plan developed by The New England Governors and the Eastern Canadian Premiers. By signing the agreement, Connecticut agreed to reduce its statewide greenhouse gas emissions to 1990 levels by 2010, 10 percent below 1990 levels by 2020, and 75-85 percent below 2001 levels in the long term.

DELAWARE

Existing Regulations and Policies Relevant to CCS

HB 6

This law amended the procedure for standard offer service and returning customer service suppliers to obtain approval for its decisions to meet electric supply requirements. It requires Delaware Power and Light (DP&L) to submit an integrated resource plan to the commission every other year.

- It incentivizes IGCC by explicitly including it in the list of resources that DP&L may consider in its IRP.
- It provides the commission with the authority to approve or modify the RFP. required under the IRP process taking into consideration whether the RFP values the use of new or innovative baseload technologies.
- It allows the commission to evaluate and approve proposals.

PSC Docket No. 06-241

HB 6 has resulted in a proposal by NRG to build a 600 MW IGCC unit with an option for carbon capture and sequestration. This proposal did not score well in an evaluation prepared for the Delaware Public Service Commission.

FLORIDA

Proposed Regulations and Policies Relevant to CCS

Executive Order 07-127

On July 13, 2007, Florida Governor Charlie Crist signed Executive Order 07-127, which sets statewide GHG emission reduction targets of 2000 levels by 2017, 1990 levels by 2025, and 80% below 1990 levels by 2050.

HB 549

This bill would amend the statute that currently incentivizes the construction of nuclear power plants to include IGCC plants. It provides for expanded cost recovery, waives purchased power supply bidding rules, and limits challenges to cost recovery.

- Costs are defined as all capital investments, including rate of return, any applicable taxes, and all expenses, including operation and maintenance expenses, related to or resulting from the siting, licensing, design, construction, or operation of the plant.
- Preconstruction costs are given deferred accounting treatment accruing a carrying charge equal to the utility's allowance for funds during construction (AFUDC) rate until recovered in rates.
- Alternative mechanisms for cost recovery including
  - recovery through a capacity cost recovery clause for preconstruction costs
  - recovery through an incremental increase in the utility's capacity cost recovery clause rates of carrying costs on the utility's projected construction cost balance
    - Carrying costs for applications submitted on or before December 31, 2010 shall equal the pretax AFUDC in effect at the time of enactment.
    - Carrying costs for applications submitted after December 31, 2010 shall equal the utility's existing pretax AFUDC rate unless the commission determines otherwise
- After a certificate of public need has been granted, the utility may petition for cost recovery.
- Once in commercial service, the utility may increase its base rate charges by its projected annual revenue requirements based on the jurisdictional annual revenue requirements of the plant for the first 12 months of operation. The rate of return on capital investments shall be calculated using the utility's rate of return last approved by the commission before commercial service.
- Retirement of any existing generating plant due to the operation of an IGCC plant shall result in the recovery of the net book value of the retired plant over a period of not more than 5 years. The costs shall be recovered through an increase in base rate charges.
- Prudent preconstruction and construction costs incurred following an approval of need shall be recovered through the capacity cost recovery clause even if the utility does not complete construction.
- Need must be determined within 135 days of the filing of a petition.
- Excludes IGCC plants from requirement to secure competitive proposal for power supply.
- Excludes "any cost increases due to events beyond the utility's control" from a finding of imprudence.
- Costs prior to commercial operation recovered under ch. 366 (CWIP)?

ILLINOIS

Existing Regulations and Policies Relevant to CCS

On February 13, 2007, Governor Rod Blagojevich of Illinois announced new statewide GHG emission reduction targets of 1990 levels by 2020 and 60 percent below 1990 levels by 2050.

Public Acts 92-0012 and 93-0167

The Illinois Resource Development and Energy Security Act establishes the Coal Revival Program and other provisions that offer prospective developers of clean coal plants a mix of incentives including:

- Up to $100 million/per plant in grant money for plant design, engineering and construction costs. The state has up to $500 million dollars in total available for such grants, and the amount of grant money available per project is based on estimated present value of State Retail Occupation Taxes on Illinois coal purchases for the plant over a 25-year period.

- Qualifying projects must propose a 400 MW facility that provides baseload power, or that "propose to construct a coal gasification facility that generates synthesis natural gas, chemical feedstocks or transportation fuels derived from coal."
- The Illinois Development Finance Authority (IDFA) has authority to issue $1,400 million in revenue bonds (lower credit rating, higher interest rate than moral obligation bonds) and $300 million in "moral obligation bonds" (high credit rating, low interest rate) for clean coal projects (both new and conversion plants). Project developers of clean coal projects can apply to the IDFA for financing under this program.
- Developers of a 400 MW electric generating facility or a coal gasification facility may qualify for designation as a "High Impact Business," and thus qualify for a waiver of IL sales tax on equipment and building materials; an IL investment tax credit; and a public utility tax exemption.
- Facilities designated as a "High Impact Business" may also qualify for local property taxes in IL.

220 ILCS 5/9-220(h)
Allows any gas utility to enter a 20 year supply contract for synthetic natural gas produced from the gasification of coal if the gasification facility has commenced construction by July 1, 2008. Provides that the cost is recoverable through the purchased gas adjustment clause for years 1 through 10 if:

- the gasification facility uses only high volatile bituminous rank coal with greater than 1.7 pounds of sulfur per million Btu content
- the price per million Btu is not more than $5 in 2004 dollars at the beginning of the contract term and does not exceed $5.50 at any point during the contract term
- the amount does not exceed 25% of annual system supply requirements
- the contract is entered within one year of the Act and ends 20 years after commencement of gasification.

During years 11 through 20 the commission may decide the cost is imprudent and require the company to reimburse the utility for the difference between the contract price and a prudent price determined by the commission.

20 ILCS 605/605-332
Provides financial assistance for a newly constructed electric generating facility that falls into any of three categories:

- A coal fired plant of at least 400 MW that supports creation of 150 new Illinois coal mining jobs
- Is funded by the federal Department of Energy before December 31, 2007 and supports creation of Illinois coal mining jobs
- Uses coal gasification and supports the creation of Illinois coal-mining jobs

Proposed Regulations and Policies Relevant to CCS

HB 1135 Clean-Coal Project Indemnification Act
- Requires the Attorney General to appear for and defend any owner or operator of a FutureGen project from liability for the escape or migration of injected carbon dioxide

- Requires the State to indemnify the owner or operator unless it has engaged in intentional, willful or wanton misconduct

HB 3733
- Sets forth a goal of supplying 10% of the energy used in the state from coal gasification or other clean coal technologies by January 1, 2015.

INDIANA

Existing Regulations and Policies Relevant to CCS

IC 8-1-2-6.1 Indiana Coal and Clean Coal Technology; research, development, and preconstruction expenses
- Defines "clean coal technology" as technology (including precombustion technology) that directly or indirectly reduces emissions of sulfur or nitrogen based pollutants from a new or existing electric generating facility and is either
  - Not in general commercial use at the same or greater scale in new or existing facilities in the United States as of January 1, 1989 OR
  - Funded under the Department of Energy's Innovative Clean Coal Technology program
- Allows recovery as operating expenses of expenses associated with
  - Research and development to increase the use of Indiana coal and
  - Preconstruction costs associated with deploying clean coal technology if
    - The facility utilizes primarily Indiana coal OR
    - Economic considerations or governmental requirements justify using non-Indiana coal
    - Preconstruction costs are only allowed if the commission issued a certificate of need for the project.

IC 8-1-2-6.6 Valuation of property; qualified pollution control property constructed before March 2002
- Definition of clean coal technology is same as above
- Qualified pollution control property is an air pollution control on a coal burning electric generating facility or any equipment that meets the definition of clean coal technology and has been approved for use by the commission, meets applicable state and federal requirements, and is designed to burn coal from the Illinois Basin.
- Allows a utility to request for ratemaking purposes that the commission add to the value of the utility's property the value of the qualified pollution control property under construction if:
  - The facility burns Indiana coal as its primary fuel source upon operation of the control device OR
  - The utility can prove its decision to use another coal is justified by economic or governmental requirements.

IC 8-1-2-6.7 Depreciation of clean coal technology
- Allows a public or municipally owned electric utility to depreciate clean coal technology over a period of not less than 10 years or the useful economic life of the technology, whichever is less and not more than 20 years if the facility uses or justifies failure to use Indiana coal.

IC 8-1-2-6.8 Valuation of property; qualified pollution control property constructed after March 2002.

- Changes the definition of "clean coal technology" to:
  - Technology that was not in commercial use in the United States at the time of enactment of the federal Clean Air Act Amendments of 1990 OR
  - Technology that has been selected by the Department of Energy for funding under the Innovative Clean Coal Technology and is approved for funding on or after the date of enactment of the clean air act Amendments of 1990.
- Allows utility to request that the commission add the value of the control property under construction to the value of the utility's property for ratemaking purposes.

IC 8-1-8.7 Clean Coal Technology

- Same definition as IC 8-1-2-6.1
- Requires consideration of certain factors for determination of public need:
  - Costs compared to conventional facilities
  - Any extension of useful life of facility
  - Potential emissions reductions (sulfur and nitrogen based pollutants)
  - Federal sulfur and nitrogen based pollutant emissions standards
  - Likelihood of success
  - Cost and feasibility of retirement of existing facility
  - Dispatching priority
- Requires filing of estimated costs
- If the commission later revokes certificate of public need, the utility may recover its investment in the technology along with a reasonable return on the unamortized balance.
- Utility may not recover costs in excess of estimates approved by commission unless it proves them to be necessary and prudent
- Allows utility to opt in to ongoing review of construction costs to receive approval of proposed increase in cost estimates. If the commission approves the increase, then challenges to its addition to the rate base on the basis of excessive cost, inadequate quality control, or inability to employ the technology are foreclosed.
- If utility instead decides to put off commission review until after completion,
  - And the commission has annually approved the continuing need for the project then the utility may recover the amount it filed in its application for a certificate of public need and challenges to its inclusion in the rate base are limited to claims of inadequate quality controls.
  - Costs in excess of those approved by the commission shall not be recovered unless the utility shows they were necessary and prudent.

IC 8-1-8.8 Utility Generation and Clean Coal Technology

- Clean Coal technology includes technology that directly or indirectly reduces emissions of sulfur, mercury, or nitrogen oxides or other regulated emissions and
  - That was not in general commercial use in new or existing facilities in the United States at the time of the enactment of the federal Clean Air Act Amendments of 1990 OR
  - Has been selected by the Department of Energy for funding under its Innovative Clean Coal Technology Program and is approved for funding after the date of enactment of the federal Clean Air Act Amendments of 1990.

- Creates the following financial incentives
  - Timely recovery of costs incurred during construction and operation
  - Up to three percentage points on return on shareholder equity than would otherwise be allowed
  - Financial incentives for purchase of synfuel including cost recovery and higher return
  - Any other financial incentives the commission considers appropriate.
- Requires determination of eligibility within 120 days of application.
- Cost recovery through rate adjustment mechanism

IC 8-1-22.5 Gas Pipeline Safety

- Includes the "gathering, transmission or distribution…by pipeline; or the storage…of carbon dioxide fluids" in the definition of "transportation."
- Defines carbon dioxide fluid as a fluid consisting of more than 90% carbon dioxide molecules compressed to a supercritical state

Proposed Regulations and Policies Relevant to CCS

SB 206

- Would expand all definitions of clean coal technology in the existing statutes to include emissions associated with coal combustion that are regulated or reasonably anticipated to be regulated by the federal, state, political subdivision of a state, or any agency or unit of the above governments.
- Would add a new section to advance emissions reductions from "existing generating facilities" by allowing
  - Timely cost recovery including capital, operating, maintenance, depreciation, tax and financing costs incurred during construction and operation
  - Recovery of costs for the purchase of emissions allowances or payment of emissions taxes
  - Recovery of up to 3 additional percentage points on rate of return.

HB 1713

- Requires commission to issue approval or denial within 120 days of application for certificate of public need
- Allows utility to apply for a retail rate adjustment mechanism to provide linear recovery of forecasted costs
- Allows utility to begin recovering costs as soon as all certificates are issued

HB 1714

- Would allow the commission to consider the ability of a facility to export electricity thereby promoting the use of Indiana coal and the reliability of the regional market when assessing a utility's long range plan or determining whether to approve a petition for construction, purchase or lease of any facility.
- Would expand the definition of "eligible business" under IC 8-1-8.8-6 from facilities that primarily serve Indiana retail customers to include facilities that serve Indiana customers and sell or export electricity.

HB 1722

- Expands tax credits for integrated gasification combined cycle to produce electricity to include integrated gasification combined cycle to produce substitute natural gas.

- If the commission approves a contract for the purchase of substitute natural gas then it shall allow cost recovery on a timely basis throughout the contract term for:
  - All costs in connection with purchases under the contract including transportation and storage
  - Costs for replacement gas is seller fails to deliver including additional costs and costs of hedging not paid by seller
  - Other reasonable and necessary associated costs upon petition

- Provides for cost recovery through fuel adjustment or other rate adjustment clause
- Protects the buyer from adverse conditions throughout term of contract
  - Conditions authorization of a customer choice program on a proportionate assignment of a utility's purchase obligation under its contract to the service providers in the program
  - Regardless of market changes, the commission cannot take any action that would negatively affect the utility's cost recovery
  - No other state entity may interfere with cost recovery for the contract
- Financial Incentives
  - Timely cost recovery for new energy producing and generating facilities through a rate adjustment mechanism

KANSAS

Proposed Regulations and Policies Relevant to CCS

HB 2419

- Regulation of carbon dioxide injection wells
  - Requires the state corporation commission to adopt rules and regulations for the injection and maintenance of underground storage of carbon dioxide
  - The commission shall establish fees for permitting, monitoring and inspecting the injection wells and underground storage. These fees shall be deposited into a carbon dioxide injection well and underground storage fund.
  - Permit holders must demonstrate annually their financial ability to cover the cost of closure of the facility.
  - The carbon dioxide injection well and underground storage fund may be used to pay for permitting and compliance activities, remediation plans, mitigation of adverse environmental impacts, and legal costs.
  - The commission may assess up to $10,000 per violation per day.
  - Provides commission with the right to enter upon land to investigate, halt or clean up escape or pollution from a well.

- Income tax reductions and property tax exemptions
  - Allows property tax exemption and a tax deduction from Kansas adjusted gross income for carbon dioxide capture, sequestration or utilization technology and electric generation units which capture and sequester all carbon dioxide and other emissions.

HB 2429

- Creates the Kansas Energy Enhancement and Environmental Reclamation Fund which would provide funding for, inter alia, carbon sequestration research and development.

KENTUCKY

Kentucky requires the establishment of procedures to enable one-stop environmental permitting for coal-fired electric generating plants.

Existing Regulations and Policies Relevant to CCS

KRS 224.10-225

- Requires the secretary of the Environmental and Public Protection Cabinet to develop procedures for one-stop shopping for environmental permits for coal-fired electric generating plants.

Proposed Regulations and Policies Relevant to CCS

SB 196

- Applies to "industrial energy facilities" defined as a facility that produces electricity, synfuel, chemicals, or transportation fuels through gasification using coal, coal waste, or biomass and costing over $750 million at the time of construction.
- Amends KRS 224.10-225 to include "industrial energy facilities" one-stop shopping for environmental permits.
- Requires setting of time limits for action on permits.

Expedites review of decisions in circuit court of the county where the project will be located.

MASSACHUSETTS

Existing Regulations and Policies Relevant to CCS

On August 26, 2001, Massachusetts Governor Jane Swift signed onto The Climate Change Action Plan developed by The New England Governors and the Eastern Canadian Premiers. By signing the agreement, Massachusetts agreed to reduce its statewide greenhouse gas emissions to 1990 levels by 2010, 10 percent below 1990 levels by 2020, and 75-85 percent below 2001 levels in the long term.

MAINE

Existing Regulations and Policies Relevant to CCS

On May 21, 2003, Maine Governor John Baldacci signed into law the Act to Provide Leadership in Addressing the Threat of Climate Change, which established statewide GHG emission reduction targets of 1990 levels by 2010, 10 percent below 1990 levels by 2020, and 75-80 percent below 2003 levels in the long term. Maine set similar targets in 2001 when it signed onto The Climate Change Action Plan developed by The New England Governors and the Eastern Canadian Premiers.

MINNESOTA

Existing Regulations and Policies Relevant to CCS

S.F. 145 Next Generation Energy Act
In May 2007, Governor Tim Pawlenty signed into law S.F. 145, the Next Generation Energy Act, establishing statewide GHG emission reduction goals of 15 percent by 2015, 30 percent by 2025, and 80 percent by 2050, based on 2005 levels.

216B.1693 Clean Energy Technology Act
- Defines clean energy technology as technology using coal as the primary fuel in a highly efficient combined-cycle configuration with significant reduction of emissions of criteria pollutants compared to traditional technologies.
- Requires a utility that owns a nuclear generating facility to supply at least two percent of the energy it provides to retail customers from clean energy technology if the commission finds that a clean energy technology is likely to be a least cost resource.

216B.1694 Innovative Energy Project
- Includes IGCC technology as an innovative energy project
- Provides regulatory incentives for innovative energy projects that make a good faith effort to obtain funding from the U.S. Department of Energy and Department of Agriculture for a demonstration project for geologic or terrestrial carbon sequestration.
- Regulatory incentives include
  - Waiver of certificate of need
  - Eligibility for increased capacity without additional review
  - Power of eminent domain for sites and routes approved by the Environmental Quality board
  - Qualifies as a clean energy technology
  - Consideration of the project as a supply option before any approval by the commission to build or expand a fossil-fuel fired facility or purchase power for a period longer than five years from such a facility.
  - Entitlement to a contract with a public utility owning a nuclear facility to provide 450 MW of base-load capacity under a long-term contract
  - Eligibility for a grant of $2 million/year for five years

MONTANA

Existing Regulations and Policies Relevant to CCS

HB 25
- Prohibits the state Public Utility Commission from approving electric generating units primarily fueled by coal unless a minimum of 50 percent of the CO_2 produced by the facility is captured and sequestered. The law applies only to electric generating units constructed after January 1, 2007.

Proposed Regulations and Policies Relevant to CCS

HB 24

- Applies common carrier status to pipelines moving carbon dioxide
- Extends the right of eminent domain to underground reservoirs suitable for storing carbon dioxide

HB 55

- Authorizes use of state trust lands for carbon sequestration
- Allows lease term of up to 99 years
- Sets forth requirements for procedures and permitting
- Authorizes collection of fees or bond requirements

HB 227

- Establishes a revolving loan account for terrestrial carbon sequestration activities.

HB 282

- Provides that for permit applications filed after enactment, the Board of Environmental review shall include requirements that all coal-fired electrical generating units sequester or offset 100% of their carbon dioxide emissions.

SB 105

- Property tax exemption for carbon capture and storage equipment

SB 218

- Requires the Board of Environmental Review to adopt rules for a carbon dioxide sequestration program excluding the injection of carbon dioxide for enhanced oil recovery
- Requires establishment of permitting system, evaluation of sites, recordkeeping and reporting requirements, procedures for well operation, verification and monitoring and mitigation and restoration.
- Authorizes the Board to set fees for permits and penalties of up to $10,000 per day per violation.

NEW HAMPSHIRE

Existing Regulations and Policies Relevant to CCS

On August 26, 2001, New Hampshire Governor Jeanne Shaheen signed onto The Climate Change Action Plan developed by The New England Governors and the Eastern Canadian Premiers. By signing the agreement, New Hampshire agreed to reduce its statewide greenhouse gas emissions to 1990 levels by 2010, 10 percent below 1990 levels by 2020, and 75-85 percent below 2001 levels in the long term.

NEW JERSEY

Existing Regulations and Policies Relevant to CCS

On July 6, 2007, New Jersey Governor Jon S. Corzine signed into law the Global Warming Response Act, A3301, which limits the level of statewide GHG emissions, and GHG emissions from electricity generated outside the state but consumed in the state, to 1990 levels by 2020 and to 80 percent below 2006 levels by 2050. These targets were previously set in Executive Order 54 which the Governor signed in February 2007.

NEW MEXICO

Existing Regulations and Policies Relevant to CCS

Executive Order 2005-033

On June 9, 2005, New Mexico Governor Bill Richardson issued Executive Order 2005-033, which set statewide GHG emission reduction targets of 2000 emission levels by 2012, 10 percent below 2000 levels by 2020, and 75 percent below 2000 emission levels by 2050.

Proposed Regulations and Policies Relevant to CCS

SB 994

- Defines Clean Energy Project as constructing or modifying an electric facility with technology that has increased financial risk due to lack of commercialization generally or under specified conditions that, with respect to carbon dioxide:
  - Captures and sequesters carbon dioxide emissions to the extent that no more than 1100 pounds/MWh are emitted by the later of January 1, 2017 or eighteen months after commercial operation.
- Requires the commission to allow cost recovery for pre-approved development and construction costs of a clean energy project.
  - The utility recovers the approved costs expended at the time the utility files a general rate case regardless of whether the project moves ahead.
  - The utility may also recover, through a general rate case, costs for reducing air emissions below the levels required by law if the commission approves them as reasonable.
- Allows the commission to open a docket to consider performance-based financial or other incentives.
- Provides tax credits for an electric facility that, with respect to carbon dioxide, captures and sequesters its emissions to produce no more than 1100 pounds/MWh by the later of January 1, 2017 or eighteen months after commercial operation.
  - If this level of emissions in not achieved, the taxpayer may be required to refund to the state all or a portion of the tax credits.

NEW YORK

Existing Regulations and Policies Relevant to CCS

Advanced Clean Coal Power Plant Initiative

This is an incentive program originally administered through the Governor's Office on Regulatory Reform to work with qualifying developers to build a clean coal plant[110] able to readily incorporate carbon capture and storage technologies (the state hopes to the qualifying project will incorporate CCS as soon as it begins

[110] In its RFP, ACCPPI, defines "clean coal technology" as "include[ing] integrated gasification combined cycle (IGCC), ultra-supercritical pulverized coal (USC PC) and supercritical fluidized bed combustion technologies (SC FBC). All are capable of meeting very low emission requirements." See New York State Advanced Clean Coal Power Initiative Request for Proposal Addendum C: Statewide Site Evaluation," ACCPPI, September 15, 2006, at pg. 1, available at: http://www.gorr.state.ny.us/ACCPPI_Addendum-C_Site_Evaluation.pdf.

operation). It chooses a project through a New York Power Authority (NYPA) RFP and provides the winning bidder with the following incentives:

- A power purchase agreement with NYPA
- Potential to have NYPA as a minority share partner
- Clean Coal fund of $10 million/year for 5 years to implement CCS
- Up to $200 million/year in bonding authority
- Empire Zone benefits (tax credits) regardless of location

The initiative also created a "Shovel-Ready Team" which evaluated over 120 sites for the development of facilities with carbon capture and sequestration. It pre-qualified 25 sites, a valuable exercise for future CCS projects. The team included representatives from the NY Governor's Office of Regulatory Reform (GORR), the NY Power Authority (NYPA), New York State Energy Research and Development Authority (NYSERDA), the NY Department of Environmental Conservation (DEC), the Empire State Development (ESD), and the NY Public Service Commission (PSC).

ACCPPI issued an RFP for developers' proposals for coal plants of up to 600 MW on September 1, 2006, and in December 2006 NYPA announced the conditional awarding of a PPA to NRG Energy for its proposed strategic alliance to build a clean coal power plant at its Huntley Generating Station in the Town of Tonawanda in Erie County. The proposed plant will be a 680 MW IGCC plant. However, the cost of the proposal (over $1 billion) was considered too high for NYPA. Instead, the parties have entered into a "strategic alliance" to work together to make the project financially feasible.

State GHG Targets
In June 2002, the State Energy Planning Board released The 2002 State Energy Plan and Final Environmental Impact Statement, which established goals to reduce statewide GHG emissions to 5 percent below 1990 levels by 2010, and 10 percent below 1990 levels by 2020.

NORTH DAKOTA

Existing Regulations and Policies Relevant to CCS

NDCC 49-19-01 et seq. (Pipeline)
- North Dakota's existing statute governing common pipeline carriers includes the transport of carbon dioxide. It denotes such a pipeline as a common carrier and extends the same rights and obligations to carbon dioxide pipelines including the power of eminent domain and the obligation to carry without discrimination.

NDCC 49-05-16 (Advance Prudence)
- Provides the opportunity for an "advance prudence review" of proposals to construct, lease, or modify an energy facility or to purchase power.
- Requires the utility to file an estimate of costs
- Requires the commission to enter an order within seven months of the application

- Is binding for ratemaking purposes
- Subjects the project to annual review
- Allows recovery (including interest expense and a return on equity) even if subsequent review determines the project is no longer prudent and should not be completed.
- Eligibility for a grant of $2 million/year for five years.

OHIO

Existing Regulations and Policies Relevant to CCS

RC § 1555.01

- Defines coal research and development as projects to advance scientific or technical knowledge or use existing or new knowledge to use Ohio coal in an environmentally acceptable manner
- Defines coal research and development facilities as building, structures and other improvements, equipment and other property, real and personal or modification or replacement of property for coal research and development
- Defines coal research and development project as any of the above within the state of Ohio that is being paid for in part or whole from a loan or grant from the Ohio coal development office.
- Defines cost expansively as the cost of acquisition and construction, cost of acquisition of all land, property rights, easements, and interests required for such acquisition and construction, the cost of demolishing or removing any buildings or structures on land so acquired, including the cost of acquiring any lands to which such buildings or structures may be moved, the cost of all machinery, furnishings, and equipment, financing charges, interest prior to and during construction and for no more than eighteen months after completion of construction, engineering, legal expenses, plans, specifications, surveys, estimates of cost and revenues, working capital, other expenses necessary to determining the feasibility or practicability of acquiring or constructing such project, administrative expense, and such other expense as may be necessary to the acquisition or construction of the project, the financing of such acquisition or construction, and the financing of the placing of such project in operation. Any obligation, cost, or expense incurred by any such person or educational or scientific institution for surveys, borings, preparation of plans and specification, and other engineering services, or any other cost described above, in connection with the acquisition or construction of a project may be regarded as a part of the cost of such project.

RC § 4901:1-12-01

- Provides for a special cost adjustment mechanism through a provision in the schedule of a gas or natural gas company that allows recovery on a uniform basis for Ohio coal research and development costs rather than going through a rate case.
- Establishes a method to separate Ohio coal research and development costs from all other costs of gas or natural gas companies.
- Allows recovery through a semiannually updated coal research and development rate.
- Establish procedures for investigation and review of a company's coal research and development projects and recovery of costs.

- Requires monthly and semiannual reports on the coal research and development costs and funding received through grants to ensure that only net costs are recovered by the company
- Sets forth the method for calculating the research and development rate which involves subtracting the costs to be refunded from the costs to be recovered and requires reconciliation for any under or over-recoveries.
- Requires inclusion of the coal research and development rate in costs per Mcf or Ccf and the total charge for the rate in dollars and cents on customer bills.

OAC ch. 4906.02

- Establishes the Ohio Power Siting Board which consists of the chairperson of the public utilities commission, the directors of the environmental protection, health, development, natural resources, agriculture and a representative from the public.
- This is essentially a one-stop shopping agency for siting permits.

OAC ch. 4906.03

Sets forth the duties of the Ohio Power Siting Board

- Provides the board with authority to create an abbreviated review process for a construction certificate for construction of a major utility facility related to a coal research and development project.(funded by the Ohio coal development office)
- Requires the board to reach a decision on an application for construction within 90 days of receiving the application and all required supporting materials.

OAC ch. 4906.04

- Requires any developers of a new major utility facility to obtain a certificate of environmental compatibility and public need from the Ohio Power Siting Board.

OAC ch. 4906.13

Certification by the Ohio Power Siting Board exempts its holder from the jurisdiction of any other state or local agency.

OAC ch. 4906.14

Authorizes the power siting board to make joint investigations, hold joint hearings, and issue joint order in conjunction or concurrence with any official or agency of any state or the United States

Ohio PUC Case No. 05-376-EL-UNC (April 10, 2006)

- Ordered that AEP, as a provider of last resort, recover its phase I (preconstruction costs) for an IGCC plant through a bypassable surcharge.
- Decided to address phase II and III costs in separate proceedings.
- Establishes one of the most comprehensive definitions of costs to be included in recovery for clean coal development projects. Allowable costs include:
    - the cost of acquisition and construction; the cost of acquisition of all land, property rights, easements, and interests required for such acquisition and construction; the cost of demolishing or removing any buildings or structures on land so acquired, including the cost of acquiring any lands to

which such buildings or structures may be moved; the cost of all machinery, furnishings, and equipment; financing charges; interest prior to and during construction and for no more than eighteen months after completion of construction; engineering; legal expenses, plans, specifications, surveys, estimates of cost and revenues, working capital; other expenses necessary to determining the feasibility or practicability of acquiring or constructing such a project; administrative expense; and such other expense as may be necessary to the acquisition or construction of the project, the financing of such acquisition or construction, and the financing of the placing of such project in operation.

- Any obligation, cost, or expense incurred by any such person or educational or scientific institution for surveys, borings, preparation of plans and specifications, and other engineering services, or any other cost described above, in connection with the acquisition or construction of a project may be regarded as a part of the cost of such project.

OREGON

Existing Regulations and Policies Relevant to CCS

HB 3543

On August 6, 2007, Oregon Governor Ted Kulongoski signed House Bill 3543, which set statewide GHG emission targets for the state. HB 3543 directs the state to stop the growth of greenhouse gas emissions by 2010 and to reduce GHG emissions to 10 percent below 1990 levels by 2020 and to 75 percent below 1990 levels by 2050.

ORS 469.503 and OAR 345-024-0500 et seq.

This statute requires the Oregon Energy Facility Siting Council to establish emissions performance standards for new electric generating facilities. The statute initially set the limit for natural gas fired baseload generating plants at 0.70lb/kwh. The Council has since reduced this rate to 0.675lb/kwh. The statute also requires the Council to establish emissions performance standards for other fossil-fueled generating units, but the Council has not yet adopted a standard. These standards may be met by offsets or by paying a fee per ton of carbon dioxide

Public Utility Commission Order No. 07-018 (Docket UM 1208) (January 16, 2007)

- Discussed concerns about the sufficiency of Pacificorp's carbon adders. Deferred decision to Docket UM 1056.

Public Utility Commission Order No. 07-002 (Docket UM 1056)

- Adopted new guidelines for its integrated resource planning process. Guideline 8 addressed the use of carbon adders: "Utilities should analyze the range of potential CO_2 regulatory costs in Order No. 93-695, from zero to $40 (1990$)."

PENNSYLVANIA

SB 1030

- Alternative Energy Portfolio Standard, requiring that qualified power sources provide 18.5 percent of Pennsylvania's electricity by 2020. There are two tiers of qualified sources that may be used to meet the standard. Tier 1 sources must make up 8 percent of the portfolio, and include wind, solar, coalmine methane, small hydropower, geothermal, and biomass. Tier 2 sources make up the remaining 10 percent of the portfolio, and include waste coal, demand side management, large hydropower, municipal solid waste, and coal integrated gasification combined cycle power generation.

RHODE ISLAND

Existing Regulations and Policies Relevant to CCS

On August 26, 2001, Rhode Island Governor Lincoln Arnold signed onto The Climate Change Action Plan developed by The New England Governors and the Eastern Canadian Premiers. By signing the agreement, Rhode Island agreed to reduce its statewide greenhouse gas emissions to 1990 levels by 2010, 10 percent below 1990 levels by 2020, and 75-85 percent below 2001 levels in the long term.

RI Gen. Laws § 42-98-2, § 42-98-3

- The state energy facilities siting board grants priority to projects based on several criteria, one of which is the use of coal processed by clean coal technology. Rhode Island defines clean coal technology as a technology developed in the U.S. Department of Energy's clean coal technology program and shown to produce emission levels substantially equal to those of natural gas fired power plants. The DOE's Clean Coal Power Initiative provides government co-financing for new coal technologies that can help utilities meet the President's Clear Skies Initiative to cut sulfur, nitrogen and mercury pollutants from power plants by nearly 70 percent by the year 2018.

TEXAS

HB 149

- 2006 legislation that instructs the Railroad Commission of Texas to acquire ownership of carbon dioxide captured by a FutureGen project located in the state (FutureGen is a proposed U.S. DOE demonstration of the integration of IGCC, hydrogen production, and CCS). This would relieve the entity operating a FutureGen project of potential liability for the carbon dioxide captured and sequestered.

VERMONT

Existing Regulations and Policies Relevant to CCS

On August 26, 2001, Vermont Governor Howard Dean signed onto The Climate Change Action Plan developed by The New England Governors and the Eastern Canadian Premiers. By signing the agreement, Vermont agreed to reduce its statewide greenhouse gas emissions to 1990 levels by 2010, 10 percent below 1990 levels by 2020, and 75-85 percent below 2001 levels in the long term.

WASHINGTON

Existing Regulations and Policies Relevant to CCS

RCW 70.94.892 Carbon dioxide mitigation—fees

- Requires the department or local air agency to keep a record of its costs for reviewing carbon dioxide mitigation plans and allows the department or local air agency to collect fees to cover those costs.

RCW 80-70-010 et seq.

- Requires carbon mitigation plans for new fossil fueled power plants or fossil fueled power plants that increase their emission of carbon dioxide by fifteen percent or more through modification.
- In order to receive a site certificate, a facility must have a plan to offset 20% of its carbon dioxide emissions through either:
  - Payment to a third party for carbon mitigation
  - Direct purchase of permanent carbon credits
  - Investment in "applicant-controlled" mitigation projects (e.g. cogeneration)

SB6001

Essentially follows the lead of California's AB 1368.

- Section 2 sets goal of reducing greenhouse gas emissions to 1990 levels by 2020 and by 2050 to the lesser of 50% of 1990 levels or 70% below the projected annual emissions for 2050.
- Section 7 requires the commission to establish by July 1, 2008, an emissions performance standard that does not exceed the greenhouse gas emissions from a combined cycle natural gas plant providing baseload generation.
- Applies to investor or consumer owned utilities, long-term financial commitments, and baseload generation.
- Section 7 directs that geologically sequestered carbon dioxide shall not be included in the calculation of emissions.
- Section 8 allows for a case-by-case exemption from the emissions performance standard.

WEST VIRGINIA

Existing Regulations and Policies Relevant to CCS

WVC 24-2-1g

Requires the commission to authorize rate incentives for utilities that invest in or purchase electricity from clean coal and clean air technology facilities.

Proposed Regulations and Policies Relevant to CCS

Senate Concurrent Resolution No. 54

- Resolves to:
  - Study sequestration of carbon dioxide
  - Study legislative options to give West Virginia a competitive advantage in attracting fossil fuel projects through comprehensive carbon dioxide sequestration statutes.
  - Study terrestrial sequestration
  - Study the legislative measures that should be applied to modeling and monitoring

SB 631

Creates the West Virginia Clean Coal Technology Council to promote the identification and advancement of cleaner coal-fired generation technologies through the coordination and oversight of pilot projects.

WISCONSIN

Proposed Regulations and Policies Relevant to CCS

Docket 9300-GF-176

This docket evaluated the following potential regulatory incentives for IGCC plants:

- Allowing IGCC applicants to provide detailed information about only one site rather than two.
- Encouraging IGCC brownfield or refueling projects by allowing the two-site requirement to be met by evaluating two sites at the same existing generation plant.
- Exempting IGCC proposals from a law requiring new plants to be located at brownfield sites.
- Monetizing greenhouse gas emissions in the resource planning process by using carbon adders.
- Classifying IGCC as best available control technology
- Establishing carbon dioxide performance standards
- Modifying RPS to allow credits for IGCC plants
- Modifying the Wisconsin's load-ordering statute to place IGCC with sequestration above other coal options or giving it the same priority as renewables.
- Giving preference to IGCC proposals with performance guarantees.
- Offering environmental trust bonds.
- Allowing a higher rate of return.
- Placing emissions caps on the purchasers of electricity to encourage power purchases from IGCC plants with capture and sequestration.
- Preapproving cost recovery.

WYOMING

Existing Regulations and Policies Relevant to CCS

Wyoming Infrastructure Authority

This agency was established in 2004 and it's mission was expanded in 2006 to take advantage of the incentives offered in the Energy Policy Act of 2005. The Authority issues an RFP for its "Wyoming Integrated Coal Gasification Demonstration Project" in July of 2006. The Authority may issue up to $1 billion in bond financing for private projects or may enter into public private partnerships. Responses to its RFP would need to propose a plant located at 4,000 feet above sea level in Wyoming, using Wyoming Coal with an energy content of 9,000 Btu/lb or less, and deploying IGCC technology with carbon capture and sequestration.

The Authority has yet to choose a winning bidder.

Although not traditionally focused on long-term carbon sequestration, Wyoming is also home to a significant amount of carbon sequestration for enhanced oil recovery (EOR) purposes– with approximately 5 million tons/yr (t/y) sequestered at sites in the state.[111] Tertiary EOR projects in Wyoming are aided by an excise tax reduction (from 6% to 4%) for the first five years of production. And, continued high oil prices are expected to lead to the expansion of possibly 2.5 million t/y of additional EOR activity in Wyoming.[112]

REGIONAL INITIATIVES :

Midwestern Regional Greenhouse Gas Reduction Accord

In November 2007, six states and one Canadian Province established the Midwestern Regional Greenhouse Gas Reduction Accord. Under the Accord, members agree to establish regional greenhouse gas reduction targets, including a long-term target of 60 to 80 percent below current emissions levels, and develop a multi-sector cap-and-trade system to help meet the targets. Participants will also establish a greenhouse gas emissions reductions tracking system and implement other policies, such as low-carbon fuel standards, to aid in reducing emissions. The Governors of Illinois, Iowa, Kansas, Michigan, Minnesota, and Wisconsin, as well as the Premier of the Canadian Province of Manitoba, signed the Accord as full participants; the Governors of Indiana, Ohio, and South Dakota joined the agreement as observers. The Accord represents the third regional agreement among U.S. states to collectively reduce greenhouse gas emissions, and will be fully implemented within 30 months.

Midwestern Energy Security and Climate Stewardship Platform

In November 2007, the Governors of 11 midwestern states and the Premier of one Canadian province individually adopted all or portions of an Energy Security and Climate Stewardship Platform. The state of Missouri later adopted portions of the agreement as well. The Platform lists goals for energy efficiency improvements, low-carbon transportation fuel availability, renewable electricity production, and carbon capture and storage development. In addition to goals related to energy efficiency, renewable energy sources, and biofuel production, the Platform lays out explicit objectives with respect to carbon capture and storage. Members agree to have in place a regional regulatory framework for CCS by 2010, and by 2012, to have sited and permitted a

[111] Coal Working Group, at 6 (citing Nuedal et al.)
[112] Coal Working Group, at 30.

multi-jurisdiction CO_2 transport pipeline and have in operation at least one commercial-scale coal-powered IGCC power plant with CCS, with additional plants to follow in succeeding years. By 2020, all new coal plants in the region will capture and store CO_2 emissions. The Platform lays out a number of policy options for member states to consider as they work towards these goals, including policies that will

1) advance a regional CCS infrastructure and a legal/regulatory framework for management and storage of capture CO_2, including assistance for geologic storage demonstrations, Enhanced Oil Recovery Projects, and reservoir assessments;

2) provide financial and regulatory incentives to building coal-fired plants incorporating CCS, such as state support for front-end engineering and design, utility cost recovery for certain commercial projects, and generally modifying state policies to favor CCS over traditional coal-fired power plants.

States adopting all or part of the Platform include Wisconsin, Minnesota, South Dakota, Illinois, Indiana, Iowa, Kansas, Michigan, Missouri, Nebraska, North Dakota, and Ohio, as well as the Canadian Province of Manitoba.

Western Climate Initiative

On February 26, 2007, Governors Napolitano of Arizona, Schwarzenegger of California, Richardson of New Mexico, Kulongoski of Oregon, and Gregoire of Washington signed an agreement establishing the Western Climate Initiative, a joint effort to reduce greenhouse gas emissions and address climate change. The states of Montana and Utah as well as the Canadian provinces of British Columbia and Manitoba, have since joined the Initiative. In August 2007, WCI members jointly set a regional, economy-wide greenhouse gas emissions target of 15 percent below 2005 levels by 2020, or approximately 33 percent below business-as-usual levels. By August 2008, participants will design a market-based system—such as a cap-and-trade program covering multiple economic sectors—to aid in meeting the target. Alaska, Colorado, Idaho, Kansas, Nevada, and Wyoming, as well as the Canadian provinces of Ontario, Quebec, and Saskatchewan and the Mexican state of Sonora, are all observing the WCI process.

Regional Greenhouse Gas Initiative (RGGI)

On December 20, 2005, the governors of seven Northeastern states announced the creation of the Regional Greenhouse Gas Initiative (RGGI). The governors of Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, and Vermont signed a Memorandum of Understanding agreeing to implement the first mandatory U.S. cap-and-trade program for carbon dioxide. Maryland, Massachusetts, and Rhode Island all joined RGGI in 2007, bringing the total number of participating states to ten. RGGI sets a cap on emissions of carbon dioxide from power plants, and allows sources to trade emissions allowances. The program will begin by capping emissions at current levels in 2009, and then reducing emissions 10% by 2019. Pennsylvania and the District of Columbia are observers in the RGGI process.

Western Governors' Association (WGA) Clean and Diversified Energy Initiative

In June 2004, the Western Governors' Association (WGA) unanimously resolved to examine the feasibility of and actions required to reach a goal of adding 30,000 megawatts of clean energy by to the region by 2015 as well as achieving a 20 percent improvement in energy efficiency by 2020. The Governors also resolved to examine what is needed to meet the West's generation and transmission needs over the next 25 years.

To investigate the feasibility of these goals and how they might be advanced, the WGA formed its Clean and Diversified Energy Advisory Committee. Based on the findings of the Committee, in 2006 the Western Governors' Association (WGA) passed a resolution reiterating their energy goals and outlining in greater detail how they might be achieved. The Governors' actions developed out of a shared desire to protect against energy shortages and price spikes, accommodate the population's growing energy needs, position the Western energy system to respond to environmental challenges, and take advantage of new technologies that will lower the cost of renewable energy and of controlling emissions from the fossil fuel resource base.[113] The first annual report tracking progress towards these goals was released in June 2007.[114]

[113] For more information on recent developments under the Initiative, see http://www.westgov.org/wga/initiatives/cdeac/index.htm
[114] See "Clean Energy, a Strong Economy, and a Healthy Environment: Western Governors' Association Clean and Diversified Energy Initiative 2005-2007 Progress Report." Western Governors' Association, June 2007. Available online at http://www.westgov.org/wga/publicat/CDEACReport07.pdf.

Appendix IIa

Table of PUC Regulatory Incentives for CCS (see Key below)

	CO	FL	IL	IN	KY	MN	MT	ND	NM	NY	OH	TX	WI	WV
Cost Recovery			3											
Preapproval	1			4,3,2				1*			1†			
Timely Recovery	1	4		4,3,2										
CWIP/Current	1	4	3											
Rate Adjustment Clauses	1	4		4,3										
Pre-construction	1	4		2					2		1†			
Power Purchases	1			4										
Higher Return				3,2									4	
Full life-cycle costs														
Cancellation	1	4		3					2					
Other		4											4	
Exemptions						1								
CPN							2							
Competitive Acquisition	1	4												
Other							2						4	
Expedited Review														
CPN		4		4	4									
Siting					4		2			1	1			
Cost Recovery				3				1*						
Financial Incentives				3									4	1*
Other						1								
Guaranteed Buyer			1							1				
Indemnity						1						1		
Eminent Domain							2							

Key:

1 = CCS Statute 3 = IGCC Statute

2 = CCS Proposal 4 = IGCC Proposal

*Statute applies to all projects

†Order or decision of public utilities commission

Appendix IIb

State Funding and Regulatory Incentives for CCS

	CA	CO	FL	IL	IN	KY	KS	MN	MT	ND	NM	NY	OH	OR	WA	WI	WV
State Funding																	
Bonds																	
Incentive Adder																	
Grants		X					X	X	X*								
Tax Credits											X						
Tax Exemptions							X		X								
Depreciation					X		X										
Regulation																	
Permitting	X						X		X								X
Pipelines					X				X	X							
Liability																	
Carbon Adder	X										X			X	X	X	
EPS	X								X					X	X	X	
Modified RPS																X	

* Terrestrial sequestration

Appendix IIc

Preliminary Criteria and Comparison of Regulatory Policies Designed to Advance CCS Projects

	EPS	Preap-proval	Higher Returns	Outages	Cancel-lation	Retire-ment	Con-solidated Siting Board	Preap-proved Sites	Waiver of Com-petitive Resource Acquisi-tion	Guar-anteed Buyer
Accelerates CCS	Medium	Medium	High	High	High	Medium	High	High	High	High
Deters PC Investments	Very High	Neutral	Neutral	Neutral	Neutral	Medium	Neutral	Neutral	Neutral	Neutral
Accountabil-ity Encour-ages Prudent Management	Normal	Low to Medium	Low	Low	Low	Neutral	Neutral	Medium	Neutral	Low
Limits Power Supply Cost Premium	Medium	Medium	Negative	Low	Low	Low	Medium (lowers costs)	Medium	Low	Low
Controls Administra-tive Costs	High	Low	Medium	Neutral	Neutral	Neutral	High	Medium	High	Neutral
Balances Risks Fairly	Neutral	Medium to Low	Low	Low	Low	Medium	Neutral	Medium	Medium to Low	Low
Promotes Innovation	High	Medium	Medium	Medium	High	Medium	Medium	Medium	Medium	Medium to High
Secures Significant Carbon Reductions	High (due to PC bar)	Medium	Medium	Low	Neutral	Medium (due to retire-ments)	Medium	High (good sites for storage)	Medium	Medium

For more information:

Dustin Bleizeffer, "Wyoming lines up 'clean' coal request," *Casper Star-Tribune*, energy, November 12, 2006, http://www.casperstartribune.net/articles/2006/11/12/news/top_story/e00e9282acc065ee8725722300268065.txt

Ellenbecker, Steven. "Energy and Climate Change in the West," workshop presentation at Innovative Approaches to Climate Change: A State and Regional Workshop, Pew Center on Global Climate Change, October 10, 2006, Washington, D.C., available at: http://www.pewclimate.org/what_s_being_done/in_the_states/state_action_events/state___regional_ws.cfm.

"Energy Security and Climate Stewardship Platform for the Midwest." November 2007; available online at http://www.wisgov.state.wi.us/docview.asp?docid=12495.

Nuedal, D, Towler, B., Mason, C. and Allen, M. (2003), The Potential of Oil Recovery in Wyoming, The University of Wyoming, April 2003 and Hargrove, B. (2004), Presentation at the 2004 Enhanced Oil Recovery Carbon Management Workshop, The University of Texas of the Permian Basin, Midland, TX http://www.spe-pb.org/en/art/?23#eor.

Pena, Naomi and Rubin, Edward S. *A Trust Fund Approach to Accelerating Deployment of CCS: Options and Considerations.* Pew Center on Global Climate Change, January 2008. Available online at http://www.pewclimate.org/white_papers/coal_initiative/trust_fund.

Vello, Kuuskraa A. *A Program to Accelerate the Deployment of CO_2 Capture and Storage: Rationale, Objectives, and Cost.* Pew Center on Global Climate Change, October 2007. Available online at http://www.pewclimate.org/white_papers/coal_initiative/ccs_demo

This paper provides an overview of the policy options available to states to encourage the deployment of carbon capture and sequestration technologies for coal-fueled power plants, including those policy tools available to state public utility commissions. It is part of a Pew Center on Global Climate Change Coal Initiative, a series of reports examining and identifying policy options for reducing coal-related GHG emissions. The Pew Center brings a cooperative approach and critical scientific, economic, technological, business and policy expertise to the global climate change debate at the state, federal and international levels.

PEW CENTER ON Global CLIMATE CHANGE

Pew Center on Global Climate Change
2101 Wilson Boulevard, Suite 550
Arlington, VA 22201

Phone (703) 516-4146

www.pewclimate.org