Concerns Regarding CO_2 NSPS for Natural Gas Combined Cycle and Coal-Fired EGUs and Geologic Sequestration & Natural Gas Infrastructure

Supporting Material for the September 4, 2013, Discussion with
Office of Management & Budget

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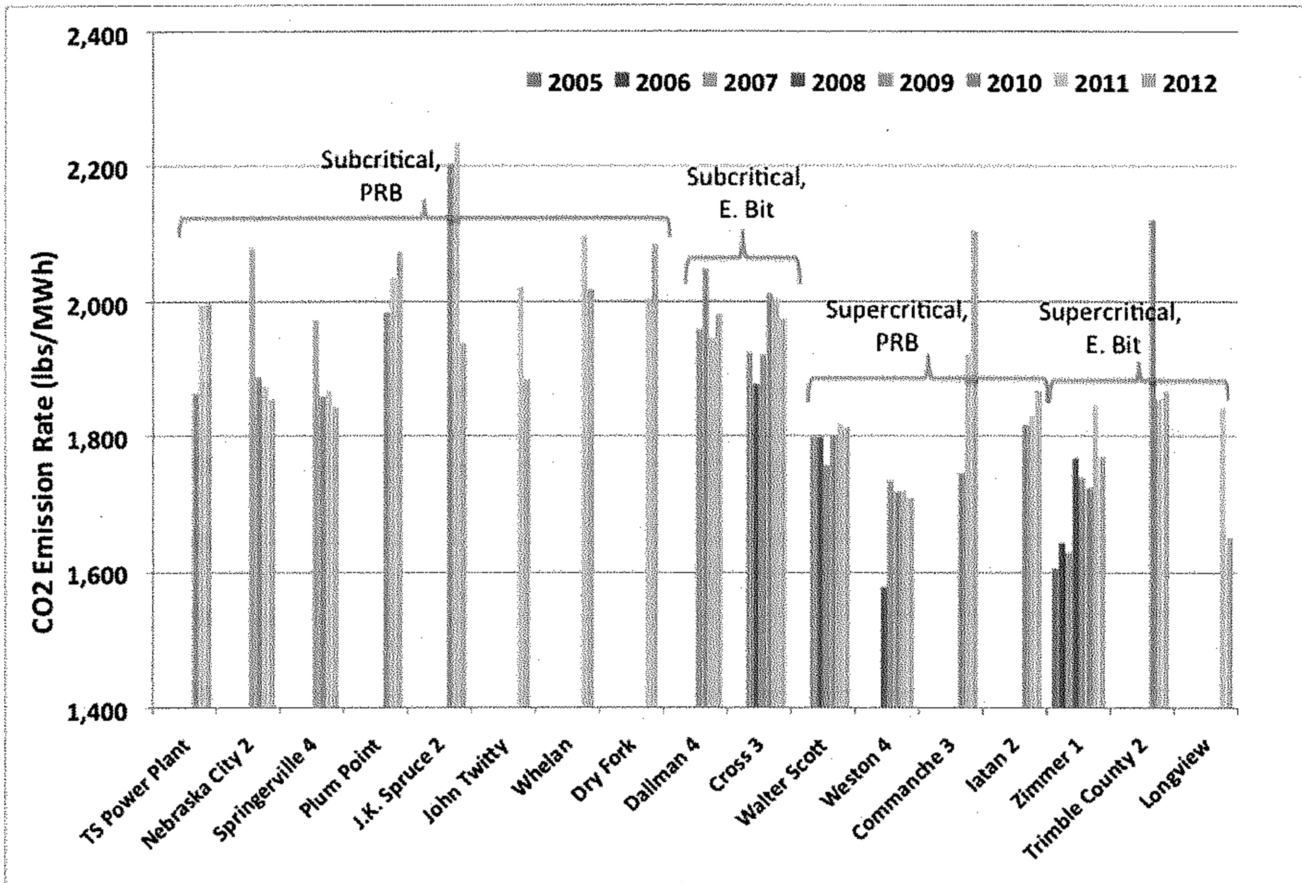
APPA's Key Issues and Concerns

- Differentiate by fuel type.
- Do not set emissions standards for coal at 1,100 lbs/MWh with CCS because it is unrealistic. No commercial plant can meet 1,100. CCS is highly unlikely to be commercially available within the 8-year NSPS review.
- Set the coal standard at a range between 1,900 and 1950 lbs/MWh (achievable by the most advanced current technology). Revisit the commercial availability of CCS at the next 8 year review.
- Set the gas standard at 1,100 lbs/MWh and provide flexibility for actual operating conditions. Life of unit(s) must consider many factors such as ramping, cycling. and altitude. EPA should call for comments on these operating issues.
- Gas infrastructure readiness is doubtful (storage and pipes); EPA should examine and consider this carefully and call for comments.
- RTO market design, especially in those with mandatory capacity markets, inhibit necessary infrastructure additions.

17 "New PC" Units Firing PRB, E. BIT



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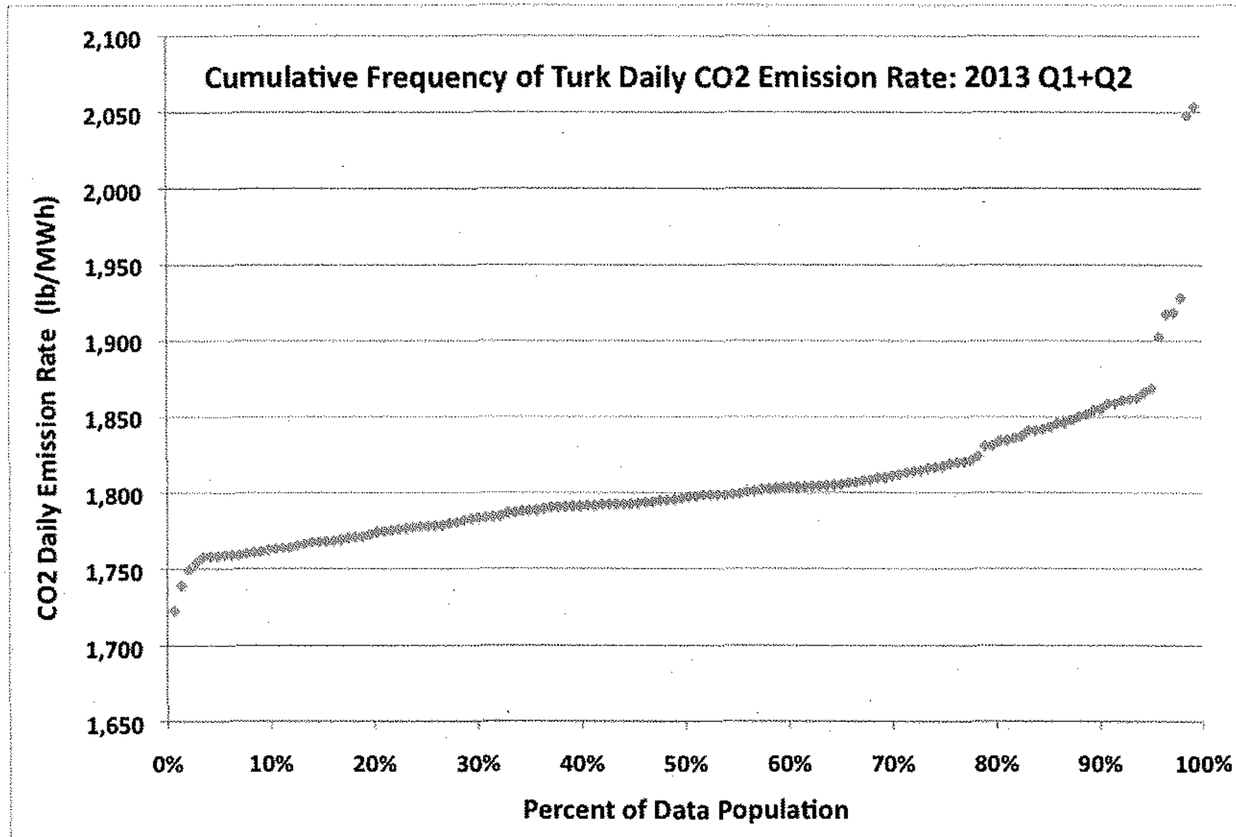
Turk Ultra-Supercritical Boiler: CO_2 Emissions Rate Variability



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Set the CO_2 Emission Rate for Natural Gas/ Combined Cycle at 1,100 lbs/MWh

- Achievable for New Generating Units
- Heat Rate/CO_2 Emission Rate Degrades with:
  - Time (component wear)
  - Non-steady operation (ramping)
- Will "Back-Up" Role for Wind Elevate CO_2 Rate?
  - *Dynamics of operation suggest "yes"*
  - NREL: *Heat rates may be higher during ramping* [1]
  - *Wind CO_2 offset 75% of predicted* [2]

[1] *Power Plant Cycling Costs*, prepared by Intertek APTECH for NREL, Report AES 12047831-2-1, April 2012

[2] *Air emissions due to wind and solar power*, Environmental Science and Technology, 2009, Jan 15, 43(2):253-8

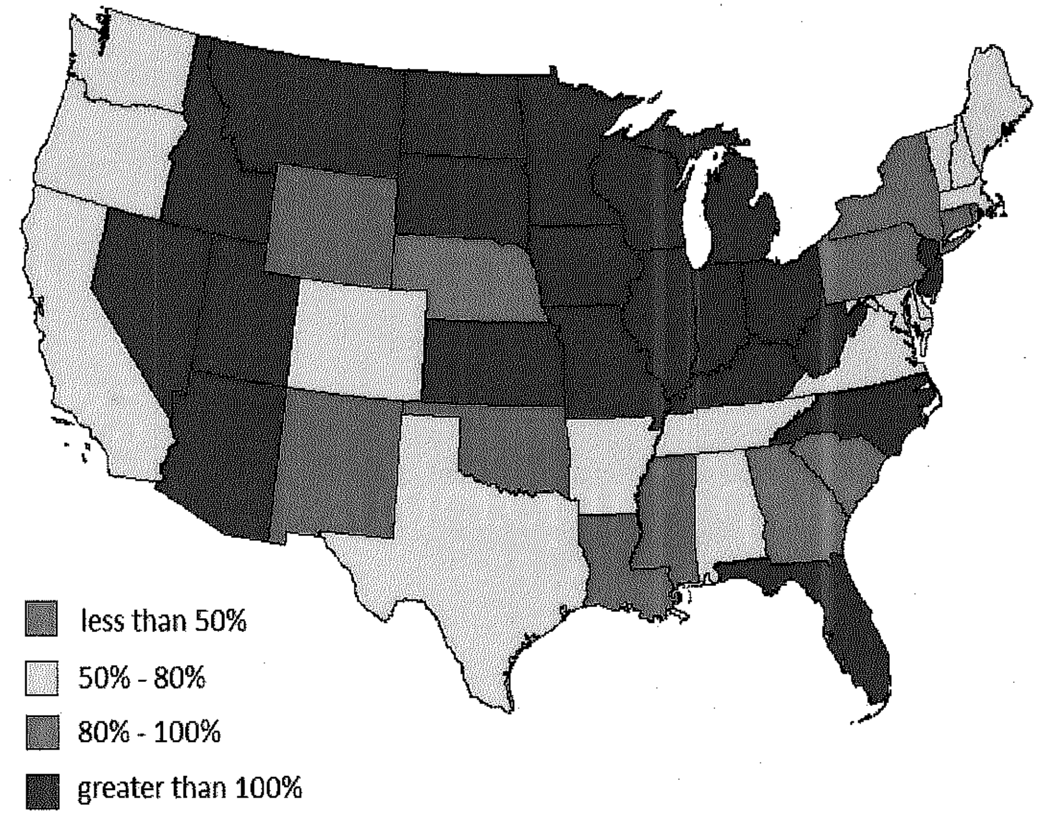
Question for EPA and OMB

- What do we know about actual CO_2 emissions from maturing NGCC over time as renewables are added and natural gas ramps to follow?
- Carnegie-Mellon Study:
  - CO_2 emission reductions from a wind or solar photovoltaic (PV) system coupled with a natural gas system are likely to provide 75% to 80% less CO_2 reduction than previously assumed.
  - Even the best system they analyzed, NOx reductions with 20% wind or solar PV penetration were 30% to 50% below what was expected.
- From Power Article
  - Researchers at the National Renewable Energy Laboratory (NREL) acknowledged in 2012 that many efforts to assess the emissions benefits of wind have failed to account for ancillary emissions from generating units that cycle or ramp to compensate for the renewable resources' intermittent generation.

Infrastructure for Natural Gas Is Essential for NGCC

- Infrastructure readiness for fuel switching to natural gas?
- Is CCS really commercially demonstrated for coal or gas?

Interstate Pipeline Capacity Utilization if an Individual State Switched Its Coal-Fired Generation to Natural Gas



Source: APPA's 2010 Natural Gas Study
Note: Reflects a presumption that over time older coal plants may be retired and replaced with natural gas. The increased percentage of natural gas in each state does not include natural gas used to back up wind or solar, do these 2010 estimates include any natural gas usage for new manufacturing or LNG exports

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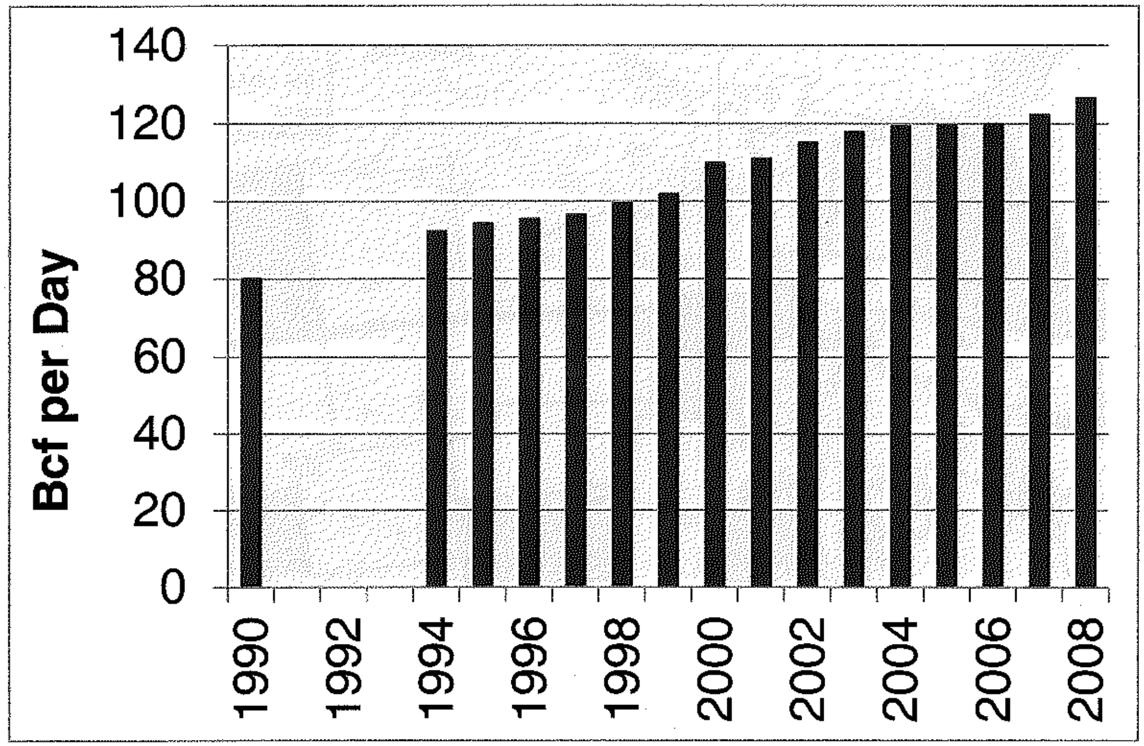
Total Interregional Pipeline Capacity 1990 to 2008



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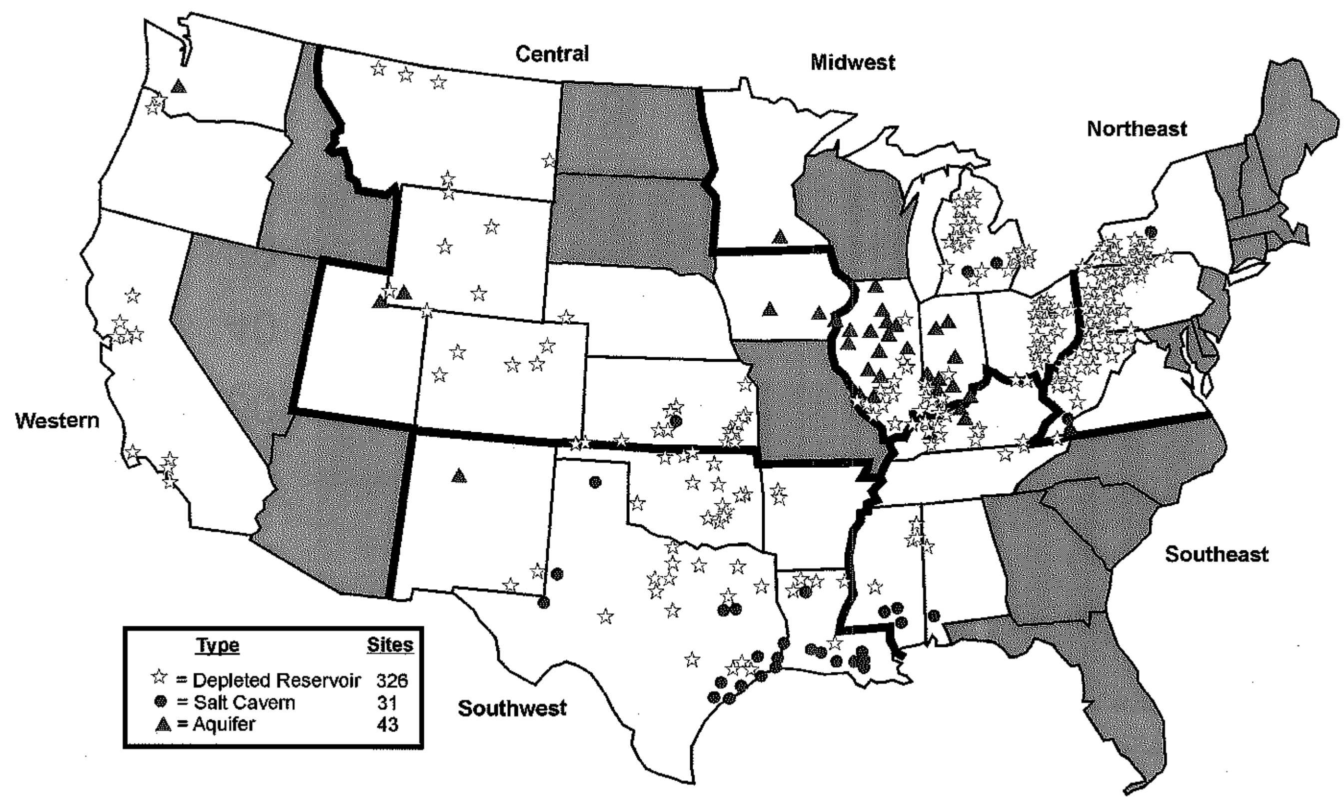
Source: Aspen Analysis of EIA data (1991 to 1993 missing from the EIA source data)

Geographic Distribution of Underground Gas Storage Facilities for Electric Utilities
Storage Is Key Because Gas Must Be within 10, 15, or 20 Minutes for Reliability



Source: APPA's 2010 Natural Gas Study
Note: reflecting no new storage permitted/built since 2010

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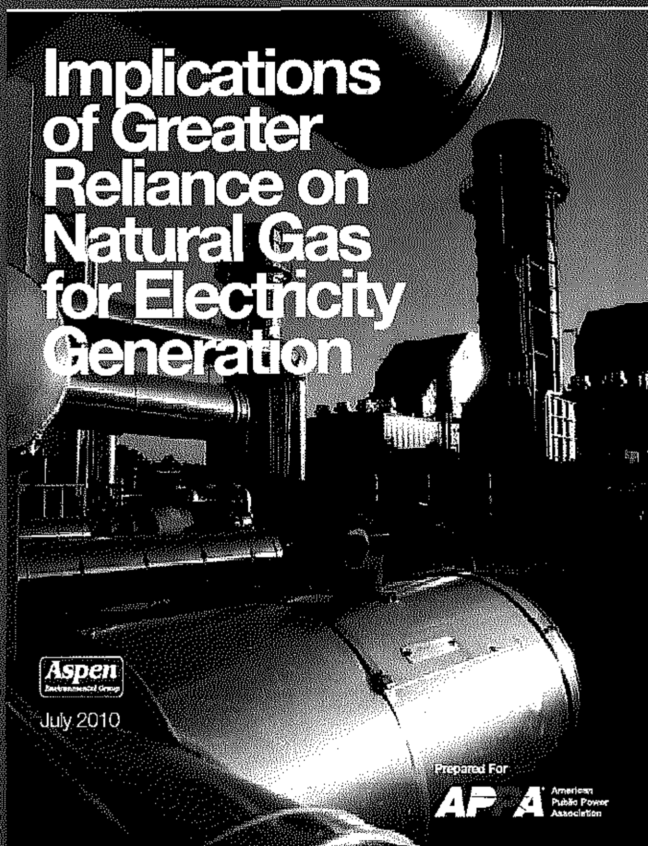
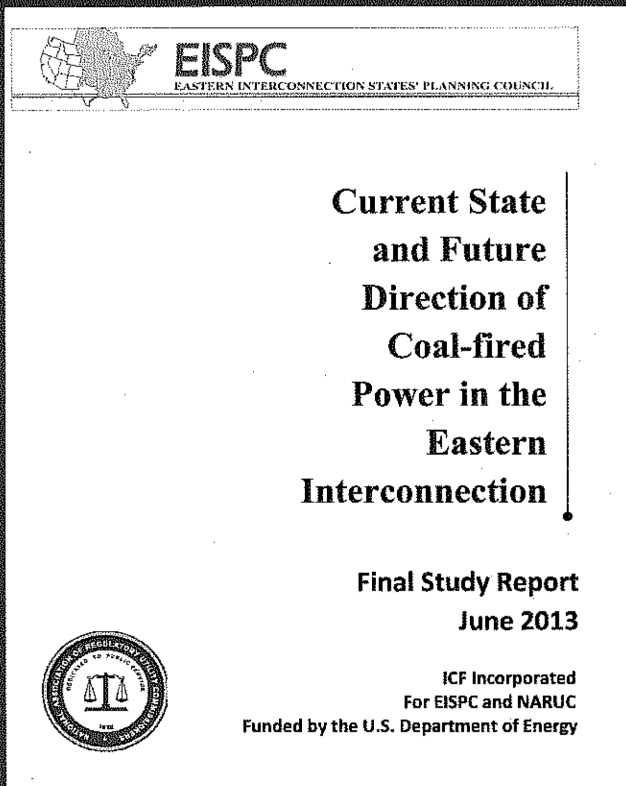
APPA Natural Gas Study



Available at:

http://www.publicpower.org/files/PDFs/ImplicationsOfGreaterRelianceOnNGforElectricityGeneration.pdf

Recommended Reading



EISPC
EASTERN INTERCONNECTION STATES' PLANNING COUNCIL

Current State and Future Direction of Coal-fired Power in the Eastern Interconnection

Final Study Report
June 2013

ICF Incorporated
For EISPC and NARUC
Funded by the U.S. Department of Energy

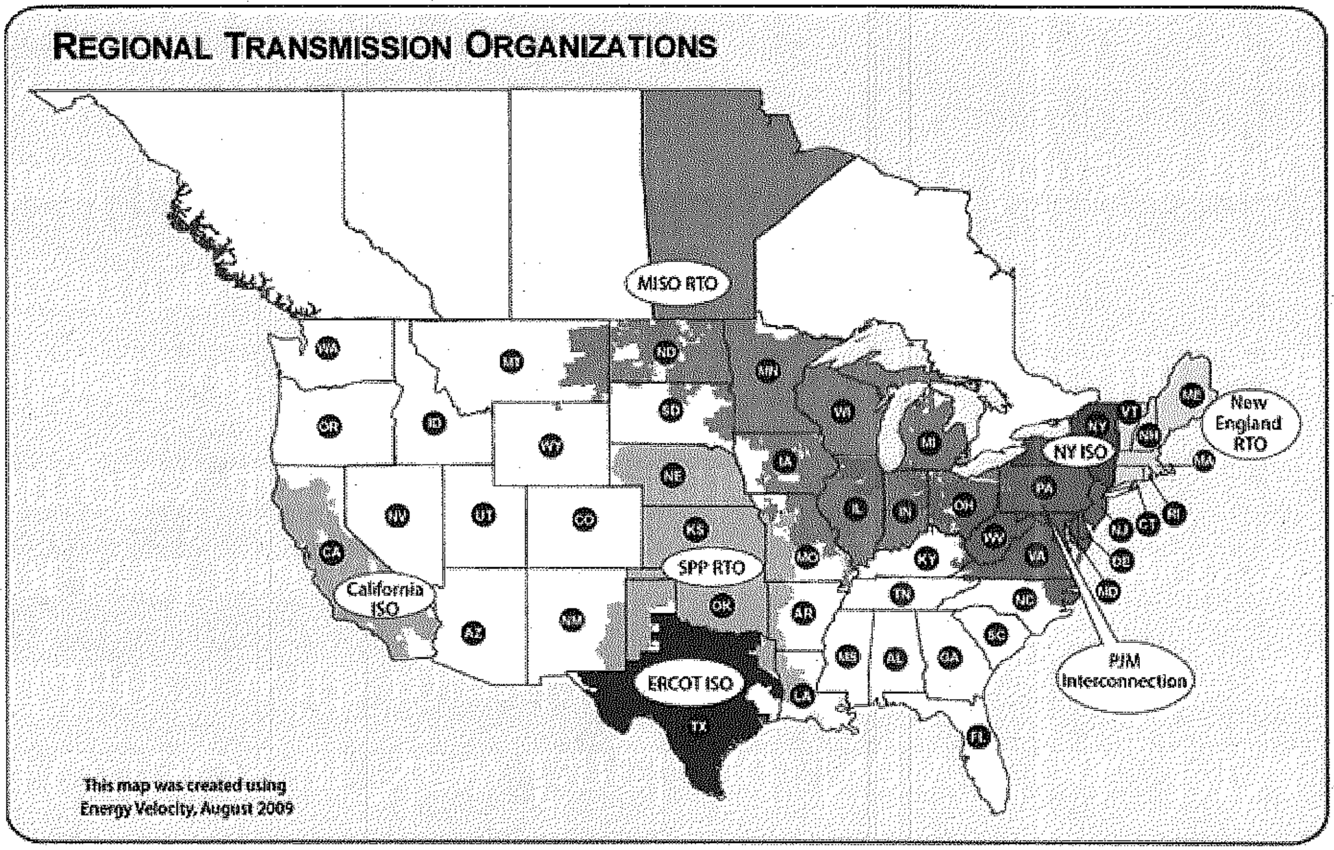
Available at:

http://naruc.org/Grants/Documents/Final-ICF-Project-Report071213.pdf

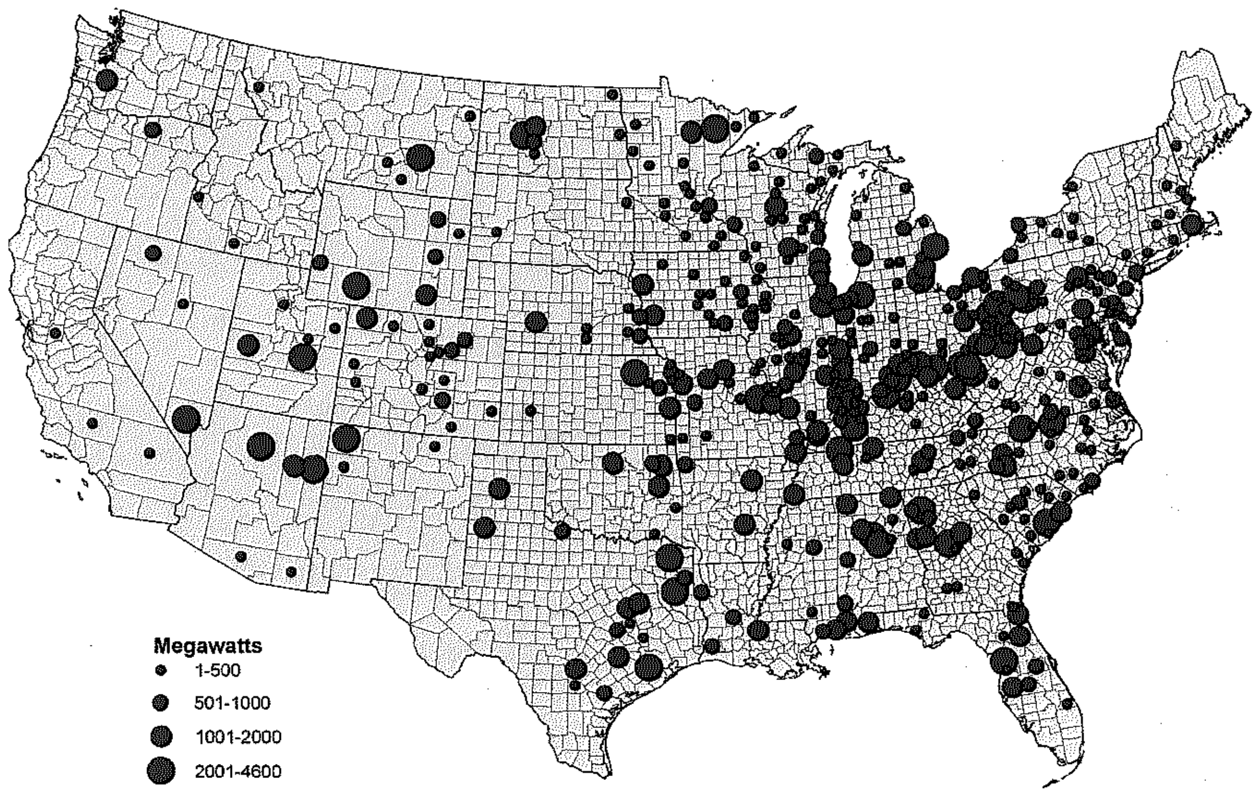
Some Wholesale Electricity Market Structures Inhibit Construction of New Infrastructure

- RTO/ISOs in New England, New York, PJM (Mid-Atlantic) with mandatory forward capacity markets
- Not real markets; administrative constructs with complex and changing rules
- Subject of numerous contested proceedings and litigation
- Short-term focus does not support long-term investments
- EPA/OMB should examine this issue closely

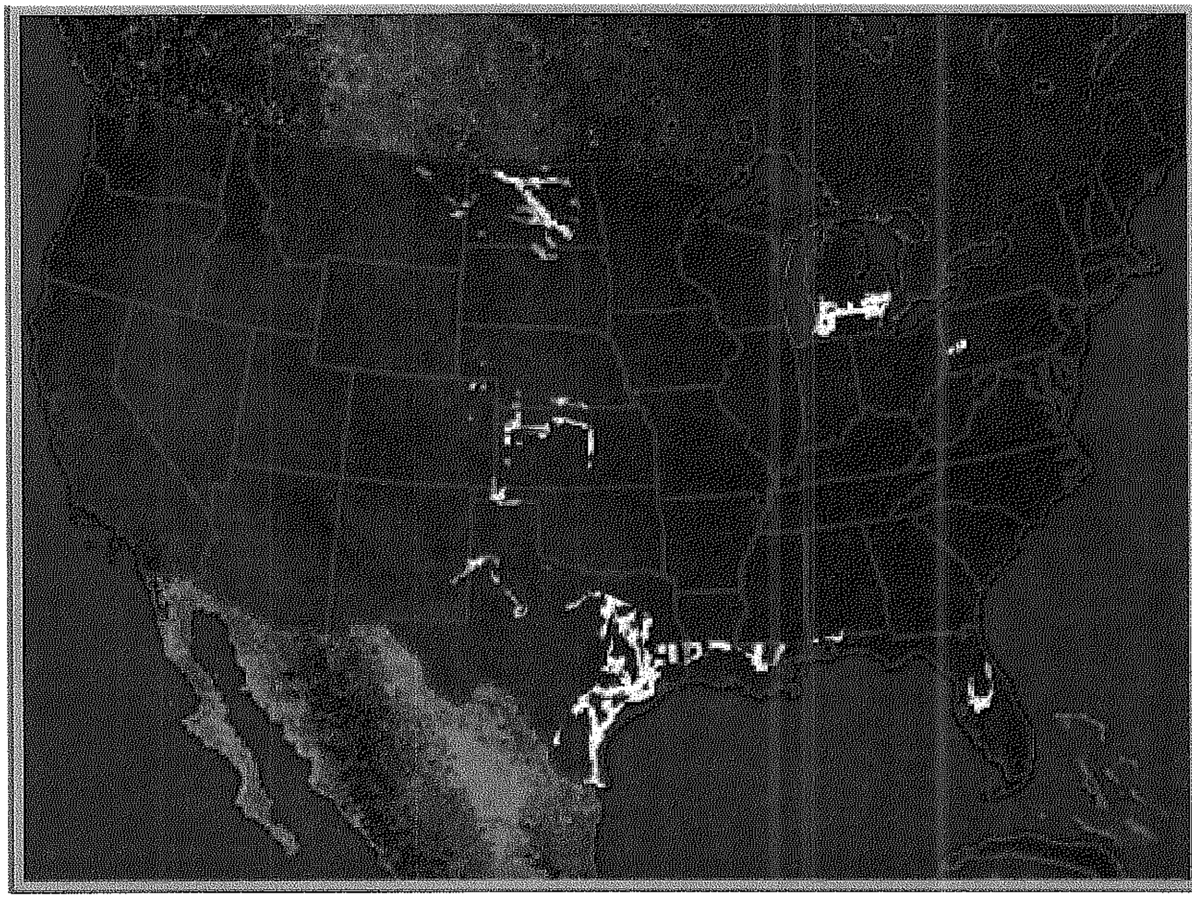
Regional Transmission Organizations/Independent System Operators



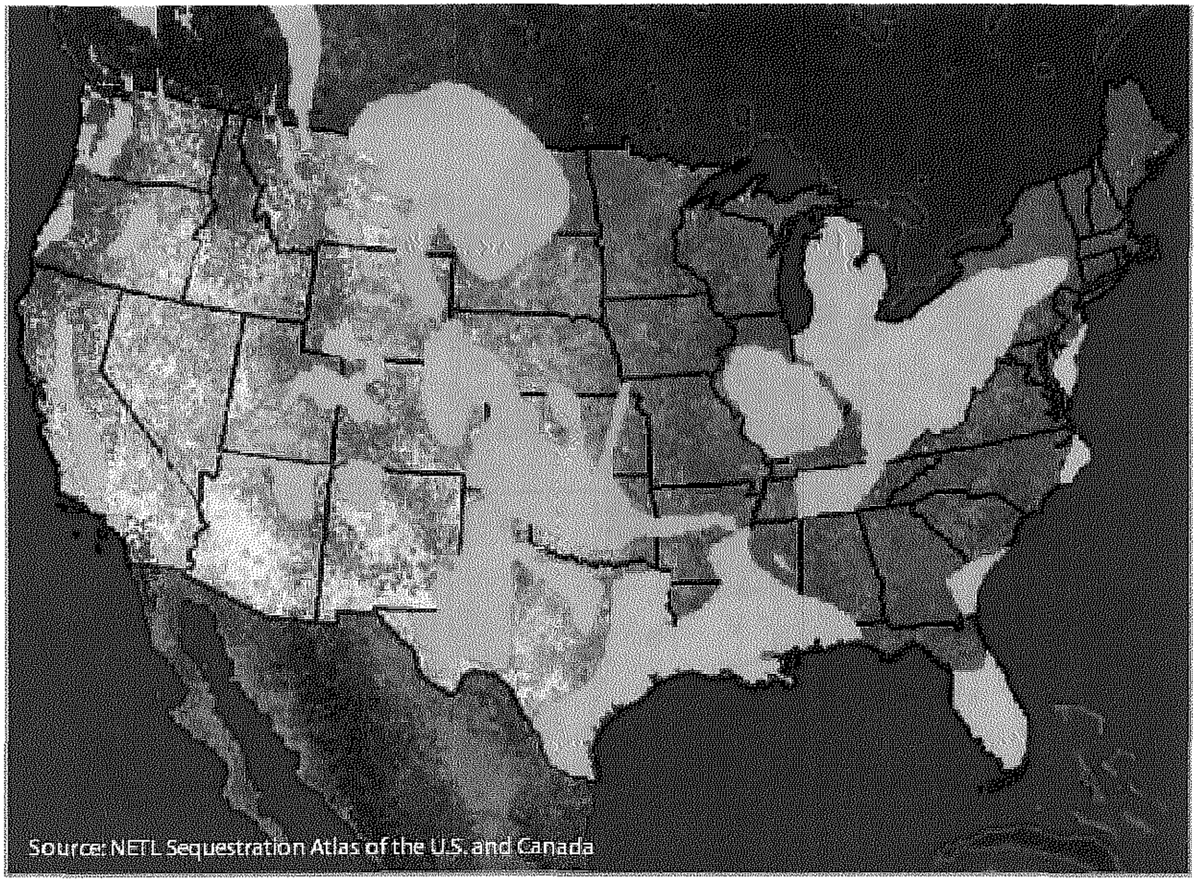
Commercial Demonstrations of CCS Require Massive Infrastructure



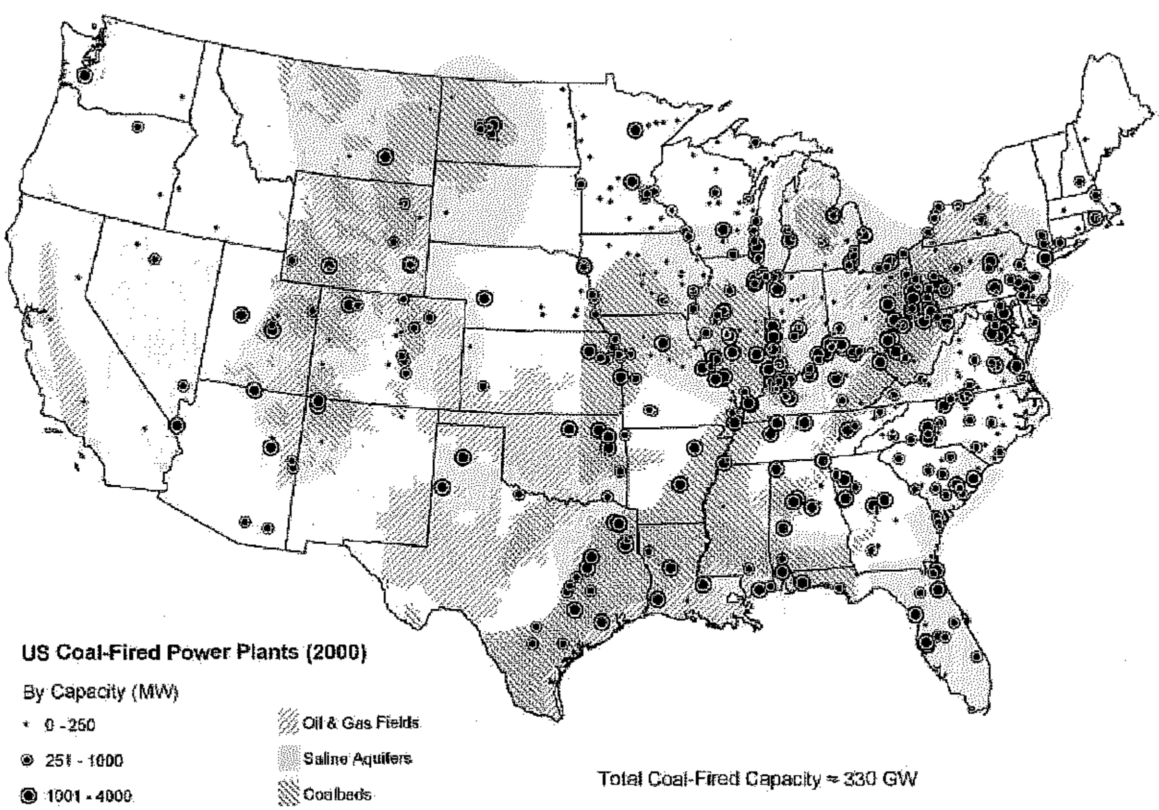
Optimal Sites – Not Requiring Proximity to Additional CO_2 Pipelines



Deep Saline Aquifer Locations May Face Competing Storage Uses: CO_2 and Water

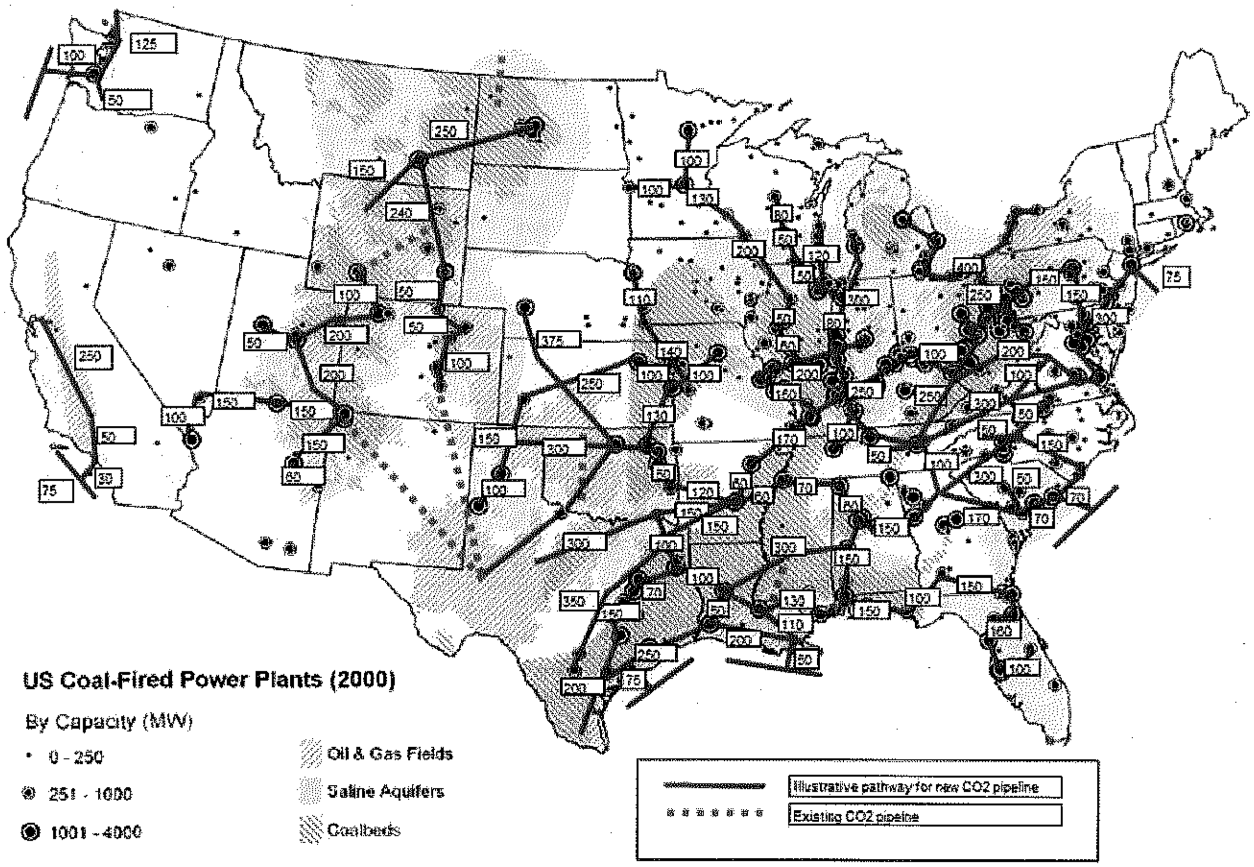


Map of US Coal Plants and Storage Sites



Source: Current State and Future Direction of Coal-Fired Power in the Eastern Interconnection, EISPC, June 2013
http://naruc.org/Grants/Documents/Final-ICF-Project-Report071213.pdf

Map of Possible CO_2 Pipeline Corridors for High CCS Case with Greater Use of EOR



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Source: Current State and Future Direction of Coal-Fired Power in the Eastern Interconnection, EISPC, June 2013 http://naruc.org/Grants/Documents/Final-ICF-Project-Report071213.pdf

North America CO_2 Geologic Potential by State

State or Area	ICF CO2 EOR Mid Volume Gtonne	ICF Depleted Oil Mid Volume Gtonne	ICF Coal Beds Mid Volume Gtonne	ICF Saline Mid Volume Gtonne	ICF Lower-48 Mid Volume Gtonne	Lower-48 Mid NATCARB Gtonne
ALABAMA	0.07	0.28	3.13	86.70	90.2	90.2
ARIZONA	0.00	0.01	0.00	0.85	0.9	0.9
ARKANSAS	0.08	0.18	2.58	31.87	34.7	34.7
ATLANTIC OFFSHORE	0.00	0.00	0.00	317.00	317.0	317.0
CA. ONSHORE	1.24	2.20	0.00	221.78	225.2	225.2
COLORADO	0.20	1.41	0.68	227.60	229.9	229.9
DELAWARE	0.00	0.00	0.00	0.05	0.1	0.1
FLORIDA	0.19	0.00	2.03	116.33	118.5	118.5
GEORGIA	0.00	0.00	0.06	11.85	11.9	11.9
IDAHO	0.00	0.00	0.00	0.39	0.4	0.4
ILLINOIS	0.10	0.00	2.16	61.91	64.2	64.2
INDIANA	0.02	0.00	0.14	49.91	50.1	50.1
IOWA	0.00	0.00	0.01	0.08	0.1	0.1
KANSAS	0.41	1.18	0.01	8.80	10.4	10.4
KENTUCKY	0.01	0.04	0.19	5.40	5.6	5.6
LA. OFFSHORE	1.46	9.61	0.00	2,133.07	2,144.1	2,144.1
LA ONSHORE	1.36	9.25	13.61	1,101.56	1,125.8	1,125.8
MARYLAND	0.00	0.00	0.00	2.96	3.0	3.0
MICHIGAN	0.08	0.69	0.00	36.56	37.3	37.3
MINNESOTA	0.00	0.00	0.00	0.00	0.0	0.0
MISSISSIPPI	0.13	0.43	8.96	335.20	344.7	344.7
MISSOURI	0.00	0.00	0.01	0.17	0.2	0.2
MONTANA	0.25	2.35	0.32	887.22	890.1	890.1
N. DAKOTA	0.32	4.09	0.60	111.65	116.7	116.7

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Source: Current State and Future Direction of Coal-Fired Power in the Eastern Interconnection, EISPC, June 2013 http://naruc.org/Grants/Documents/Final-ICF-Project-Report071213.pdf

North America CO_2 Geologic Potential by State (Continued)

State or Area	ICF CO2 EOR Mid Volume Gtonne	ICF Depleted Oil Mid Volume Gtonne	ICF Coal Beds Mid Volume Gtonne	ICF Saline Mid Volume Gtonne	ICF Lower-48 Mid Volume Gtonne	Lower-48 Mid NATCARB Gtonne
NEW MEXICO	0.90	6.45	0.19	236.89	244.4	244.4
NEBRASKA	0.02	0.01	0.00	49.86	49.9	49.9
NEVADA	0.00	0.00	0.00	0.00	0.0	0.0
NEW ENGLAND STS	0.00	0.00	0.00	0.00	0.0	0.0
NEW JERSEY	0.00	0.00	0.00	0.00	0.0	0.0
NEW YORK	0.00	0.92	0.00	4.26	5.2	5.2
N. CAROLINA	0.00	0.00	0.00	9.75	9.7	9.7
OHIO	0.00	10.06	0.13	9.94	20.1	20.1
OKLAHOMA	1.41	6.71	0.01	0.00	8.1	8.1
OREGON	0.00	0.00	0.00	52.24	52.2	52.2
PACIFIC OFFSHORE	0.00	0.20	2.30	108.00	110.5	110.5
PENNSYLVANIA	0.00	2.97	0.28	17.26	20.5	20.5
S. DAKOTA	0.00	0.19	0.00	86.69	86.9	86.9
S. CAROLINA	0.00	0.00	0.00	4.93	4.9	4.9
TENNESSEE	0.00	0.00	0.00	3.57	3.6	3.6
TEXAS ONSHORE	7.55	38.65	22.82	2,458.83	2,527.8	2,527.8
TX. OFFSHORE	0.00	5.53	0.00	1,064.93	1,070.5	1,070.5
UTAH	0.28	0.88	0.08	154.84	156.1	156.1
VIRGINIA	0.00	0.06	0.49	0.24	0.8	0.8
WASHINGTON	0.00	0.00	0.00	220.75	220.8	220.8
WEST VIRGINIA	0.00	1.83	0.41	11.21	13.4	13.4
WISCONSIN	0.00	0.00	0.00	0.00	0.0	0.0
WYOMING	0.42	1.88	12.00	644.82	659.1	659.1
Lower 48 Total	16.45	108.05	73.13	10,887.8	11,087.0	11,085.4
Offshore L-48	1.46	15.34	2.30	3,623.0	3,643.0	3,642.1

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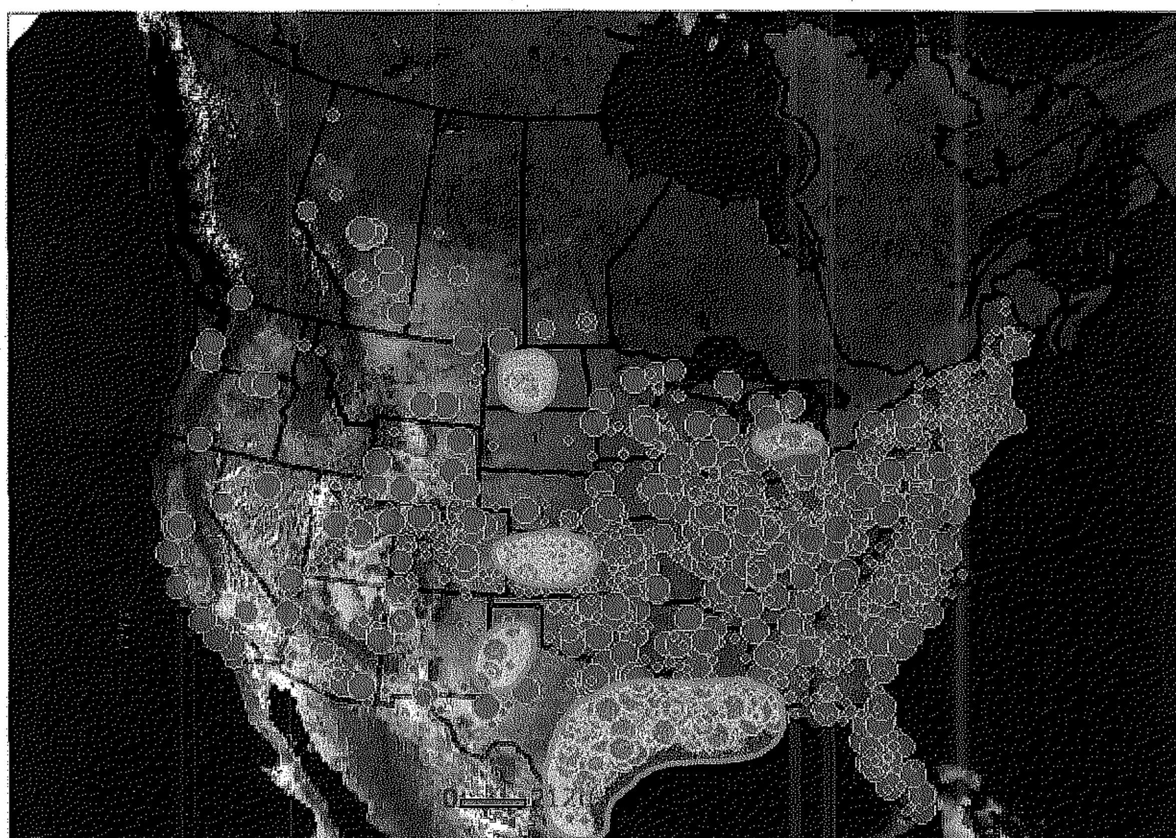
Source: Current State and Future Direction of Coal-Fired Power in the Eastern Interconnection, EISPC, June 2013 http://naruc.org/Grants/Documents/Final-ICF-Project-Report071213.pdf

Existing Fossil Generation & Optimal CCS Locations Without Any Drinking Water Resources Location Analysis



Note: Optimal Locations are for new plants, not retrofit of existing power plants
Source of Map: NatCarb Atlas; Overlay: APPA Optimal Location Criteria Maps without CO_2 pipelines

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Proposed Rule Should Address Legal & Commercial Obstacles to CO_2 injection

- Local laws banning or limiting fracking or similar drilling practices (Best Management Practices) for CO_2 injection
- Anti-fracking ordinances
- Safe Drinking Water Act and 22 state drinking water laws (*see Gablehouse paper*)
- Resources Conservation and Recovery Act (RCRA) "like kind waste" exemption for oil & gas does not apply to power sector for injecting acid gas
- Is CO_2 an acid gas subject to Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) litigation?
- Who owns and pays for the CO_2 monitoring requirements 100 years after the power plant closes under Underground Injection Control (UIC) program?
- What is financial assurance or insurance posted under UIC program for CO_2 injected for 100 years after power plant closes? How does this affect bond ratings?

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Proposed Rule Should Address Legal & Commercial Obstacles to CO_2 injection

- Not all states pool or unitize for oil/gas extraction or CO_2 injection
- Many states have no distinction between surface and subsurface space and surface owner decides
- What happens 10 years into CO_2 injection—can a new surface owner oppose and stop the project?
- Pore space may not be recognized in all states for CO_2 injection
- Not all state laws allow for the use of surface water for CO_2 injection/water lubrication (farmers/cattlemen)
- Not all banks/mortgage companies allow oil and gas leases beneath residential areas—why will CO_2 be more promising?

APPA CCS White Papers

- Retrofitting Carbon Capture Systems on Existing Coal-Fired Power Plants
- Will Water Issues/Regulatory Capacity Allow or Prevent Geologic Sequestration for New Power Plants? A Review of the Underground Injection Control Program and Carbon Capture and Storage
- Carbon Capture and Storage From Coal-Based Power Plants
- Parasitic Power for Carbon Capture
- Geologic CO_2 Issue Spotting and Analysis
- Carbon Capture and Sequestration Legal and Environmental Challenges Ahead

Available online at: http://www.publicpower.org/files/HTM/ccs.html

Two Matters Must Be Resolved before Coal-Fired Plants with CCS Are Commercially Demonstrated or Finalized

1. Is CO_2 as an acid-gas a CERCLA (Superfund) pollutant?[1]
2. How long would monitoring be required after the power plant closes?

[1] EISPC Report, June 2013, Page 179

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GEOLOGIC CO_2 SEQUESTRATION
ISSUE SPOTTING AND ANALYSIS WHITE PAPER

Timothy R Gablehouse[1]
Gablehouse Calkins & Granberg LLC

July 22, 2009

OBJECTIVE

This paper has been prepared for APPA's electric utility members and water utilities for the purpose of surveying the wide range of issues that will influence the implementation of geologic carbon sequestration. As with many things, sequestration is not as simple as it seems. Injection of anything into the subsurface is regulated. Which agencies will act to regulate and the criteria they will follow depends upon the answer to the questions raised in this paper – questions that Congress and state legislatures will need to address if sequestration is to be implemented on a scale remotely adequate to make a difference in the amount of CO_2 reaching the atmosphere.

Without a doubt sequestration projects will go forward. Many are already underway. Nothing in this White Paper should change anyone's view on the technology available for geologic sequestration. Nor should anyone read this paper to suggest that there are fatal legal impediments to these projects. There are substantial legal issues and a prudent manager would be well advised to factor these issues into the business plan for a sequestration project.

Much of this paper looks at the existing rules that apply to geologic sequestration. From where we stand today it is these rules that will apply absent action by legislative bodies. For example, if the CO_2 being injected is a waste we next need to know if its hazardous waste and

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regulated under RCRA. If injection is limited to producing oil and gas operations for enhanced recovery, then injection will be regulated by the state agencies that permit oil and gas operations.[2] The policies and procedures of these agencies and which permits might be required are sometimes radically different state-by-state having the potential to drastically change the regulatory burden and economics of any project.

Common law theories dealing with trespass, mineral rights and water rights all are implicated as injection may result in trespass or harm to surface property rights, mineral rights or water rights. Depending upon in which state injection operations occur, there are significant questions regarding the ownership and access to the subsurface spaces where the CO_2 will be placed. As the CO_2 is intended to remain in the ground in perpetuity, then we also need to examine who remains responsible in perpetuity. Regardless of whether these entities are private corporations or public entities long-term liability issues will need to be address and understood. Absent new legislative action existing statutes such a CERCLA ("Superfund") will play a role which means that the landowner, mineral owner, injection operator and the entity that produced the CO_2 all may have some liability in perpetuity.

It's important to understand what this White Paper is not intended to accomplish. While it will identify a broad range of property and liability issues associated with injection projects, it will not suggest solutions to all of them. It will not address the range of liability issues associated with the high-pressure pipeline infrastructure necessary to move acid gases from the point of generation to the point of injection. For geologic CO_2 sequestration to become broadly viable there will need to be predictability on how these issues are handled. Many will have no predictable solution until and unless we have federal and state legislation.

[2] Acid gas injection for enhanced recovery of oil & gas is different from hydraulic fracturing which is also used to enhance recovery by physically opening the subsurface formations using very high pressure, proprietary formulas and particulates to hold the fractures open.

BACKGROUND

Much work has gone into the technical review of geologic CO_2 sequestration. (Frequently this is referred to more generically as carbon capture and storage or "CCS" – the remainder of this paper will utilize this nomenclature.) Some work has gone into potential regulatory programs based upon extensions of the current EPA Underground Injection Control ("UIC") program. EPA has proposed a regulatory approach which is the topic of a September 10, 2008 White Paper available to readers. (As nothing has really changed on this front, this White Paper will not cover that effort in any detail.)

Some states are adopting regulatory programs with various degrees of complexity. In general they are based upon existing UIC programs or on injection of "acid gas" for production enhancement in existing oil or gas operations. These can be radically different approaches and the internal political situation along with the perceived importance of the oil and gas industry has a large impact.

It is critical to distinguish between production enhancement injection programs and injection of CO_2 solely for sequestration purposes as they are radically different in intent, liability, risk and regulatory regime. A mineral owner typically has substantial rights to use techniques such as fluid injection in order to produce the "minerals" like natural gas and petroleum. Oil and gas production companies have substantial experience with this activity and tend not to view it as very risky even though it's currently benign regulatory posture is under attack.

As an example, the long-term liabilities associated with production enhancement versus CCS scenarios have substantially different legal postures. For example, a land owner or even an impacted neighbor may have products liability claims against the producer of the injected enhancement fluid should it cause adverse impacts outside of the natural gas or petroleum production pool.[3] In a CCS project we would instead need to look to CERCLA or RCRA for guidance on long-term responsibility for the CO_2.

Not resolved to any satisfactory degree are the questions of legal access to property for the purpose of CCS, whether it is waste disposal or something else, liability for the entire host of things that people can imagine might go wrong, and long-term maintenance/monitoring. All one need do is examine EPA's 2008 Technical Support Document entitled "Vulnerability Evaluation Framework for Geologic Sequestration of Carbon Dioxide" to get a sense of the complexity of the problem and the difficulty of assessing potential risks.[4]

That these risks are a real concern when it comes to permitting and operation should be obvious. Some examples may help to illuminate the risks that the public will fear:

- Fluid injection is suspected of causing Texas earthquakes. *Wall Street Journal*, June 12, 2009, Page A3.
- Earthquakes caused by deep well injection of wastes at Rocky Mountain Arsenal. http://earthquake.usgs.gov/regional/states/colorado/history.php
- Crystal Geyser UT – CO_2 cold water eruptions through a manmade well. http://www.uweb.ucsb.edu/~glennon/crystalgeyser/
- 1986 Lake Nyos eruption and deaths.
- "CCS mobilization of hazardous, naturally occurring materials is a risk that must be characterized." "Injection into saline formations has the potential to disturb regional ground-water flow systems and could contaminate drinking water." Paraphrased from the testimony of Dr. Burruss, USGS, Subcommittee on Environment and Hazardous Materials, House Committee on Energy and Commerce, July 24, 2008
- Transportation infrastructure to transport CO_2 to injection sites does not exist – USGS projects that an infrastructure larger than the existing natural gas/petroleum industry will be required to achieve meaningful levels of CCS. http://energy.er.usgs.gov/health_environment/CO2_sequestration/CO2_illustrations.html

[3] See Modesto, City of v. The Dow Chemical Co., et al., No. 98-999345, Calif. Super., San Francisco Co. (liability based on products liability theories found for dry cleaning fluid off-site impacts)

[4] http://www.epa.gov/climatechange/emissions/downloads/VEF-Technical_Document_072408.pdf

ISSUES and DISCUSSION

I. Liability During Injection / Operational Liability

Operational liability includes the environmental, health, and safety risks associated with CO_2 capture, transport, and injection. Enhanced fluid recovery contractors are already subject to a duty of care defined under tort law and are usually subject to standards of conduct under their contractual arrangements. Companies providing these specific services have experience in their industries, and are subject to liability for worker safety and property damage resulting from their conduct. These companies are best positioned to manage the risks associated with their own conduct and are able to obtain liability insurance for their conduct and workers.[5] In surveys and case studies, these companies were willing to provide services on a commercial basis and generally willing to accept liability for their actions.[6]

However, it is foreseeable that large-scale CCS could make it less likely that companies will be willing to accept liability for injection. For example, if there was contamination at the surface during injection operations it could potentially affect drinking water. There is currently no law protecting commercial or public operations from the full range of liabilities should they cause contamination.

In theory government agencies could conduct the injection operations to limit liability associated with injection. An example of this is Lawrence v. Buena Vista Sanitation District.[7] Neighbors brought a trespass claim against the sanitation district, alleging contamination from leakage at the district's wastewater treatment facility but did not argue that negligence was

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[5] M.A. de Figueiredo, D.M. Reiner, H.J. Herzog, *Towards a Long-Term Liability Framework For Geologic Carbon Sequestration*, Presented at the Second Annual Conference on Carbon Sequestration, Alexandria, Va. May 2003.

[6] Craig A. Hart, *Advancing Carbon Sequestration Research in an Uncertain Legal and Regulatory Environment: A Study of Phase II of the DOE Regional Carbon Sequestration Partnerships Program*, Discussion Paper 2009-01, Cambridge, Mass.: Belfer Center for Science and International Affairs, January 2009 (finding drilling companies willing to participate in CCS and accept liability for their actions).

[7] Lawrence v. Buena Vista Sanitation Dist., 989 P.2d 254 (Colo.App. 1999)

present. The court held that the district was immune from a trespass claim under Governmental Immunity Act "unless negligence is proven". Trespass is not a dangerous condition of a public water facility or public sanitation facility; because the trespass claim did not require proof of negligence it was barred by Governmental Immunity. Nobody should take this sort of outcome as an indication that government agencies can conduct these operations with impunity – there are many other available theories of liability.

II. Post Injection Liability

A. Ownership of Pore Space

The surface owner usually owns pore space because mineral conveyances, including leases, normally only pass title to the minerals, not the pore space itself. That does not, however, end the conversation over who controls the pore space property right. The surface owner cannot violate the mineral estate owner's or lessees' rights by doing something interfering with access to the minerals, making the minerals more expensive to exploit or making the development of the minerals economically impractical. Clearly injection into the pore space could cause this sort of harm. The surface owner must also allow reasonable use of the property to give access to the mineral estate.[8] For CCS projects to proceed it is somewhat reckless to assume that agreement with the surface owner is the only necessary step. It seems prudent to have agreements with both surface and mineral owners even though it seems likely that the surface owner owns the pore space.[9]

B. Risk of Leakage

Post-injection liability includes harm to human health, the environment, property, and the climate liability related to leakage or migration of carbon dioxide from geological reservoirs and

[8] Cassinos v. Union Oil, 14 Cal.App.4th 1785 (1993)

[9] *Geologic CO2 Sequestration: Who Owns the Pore Space?*, 9 WY LR 98, 2009.

the effect on climate change. Potential pathways for carbon dioxide release include leakage through the pores of low-permeability cap rocks if the carbon dioxide is injected at too high a pressure, leakage through openings in the cap rock, leakage through abandoned or improperly sealed wells, and migration via faults.[10]

Reportedly, there is a low risk of captured carbon leaking into the atmosphere in amounts significant enough to pose a risk.[11] CO_2 and natural gas has been stored naturally in geologic formations for millions of years and companies already store natural gas underground with a lot of experience. There are naturally occurring CO_2 reservoirs in the western states that have held gas for millions of years. Furthermore, over 100 million tons of CO_2 has been injected into oil reservoirs for enhanced fluid recovery as well as into deep saline aquifers (over 80 projects have been implemented worldwide).[12] Commercial and experimental projects have shown the potential for CCS across a wide range of geological settings.

There are, however, reports suggesting that an exceptionally detailed analysis of geologic conditions is critical to understanding how the CO_2 is being sequestered in each case. Whether CO_2 is being mineral trapped, in which case it may be stable on geologic time scales, versus dissolution in groundwater is critical to an assessment of whether a potential for leakage is present. Dissolution in groundwater is not preferred as it has the greatest potential for eventual leakage to the atmosphere.[13]

The long-term liability associated with CO_2 leakage that damages health or property is difficult to establish because it is dissimilar to other regulatory schemes and has a timeframe of thousands of years. We simply do not know what risks long-term geologic storage presents.

[10] IPCC, IPCC special report on carbon dioxide capture and storage; 2005.
[11] Feidman, This work performed under the auspices of the U.S. Department of Energy by Lawrence Livermore National Laboratory under Contract DE-AC52-07NA27344
[12] Rocky Mountain Mineral Law Institute
[13] Aeschbach-Hertig, Clean Coal and Sparkling Water, NATURE, Vol 458, Page 583, April 2009.

Exposure to CO_2 typically is not dangerous except in very high concentrations (> 15,000 ppm). For example, in Lake Nyos 1,500 people died when a lake over a magma pool released large amounts of CO_2. This is unlikely to occur at injection wells when properly monitored. Researchers have successfully plugged and abandoned CO_2 injection wells, even badly damaged and failed wells. In wells that have failed and released CO_2, almost all were detected quickly and stopped.[14]

EPA produced a July 2008 white paper entitled *Approaches To Geologic Sequestration Site Stewardship After Site Closure.*[15] They describe the advantages and disadvantages of stakeholder developed models as well as models based upon existing federal laws ranging from the Nuclear Industries Indemnity Act through CERCLA. If CCS is viewed as waste disposal the "cradle-to-grave" model of the RCRA and perpetual nature of liability under CERCLA would be inconsistent with any effort to limit responsibility for injected CO_2 and especially any potentially hazardous contaminants entrained in the injected materials.

EPA's analysis has been criticized as unrealistic given that geologic storage of CO_2 is intended to be indefinite and well beyond 50 years. The authors of a recent report view this as the single greatest legal obstacle to commercial deployment of CCS.[16] Quite obviously, legislation will be required to address this issue if there is to be any time limit on liability.

C. Property Rights Issues Related to Migration of Injected CO_2

1. Natural Gas Storage Law May Provide Some Insight

[14] S. Julio Friedmann, Carbon Management Program APL Global Security Principle Directorate, LLNL. .S. Department of Energy by Lawrence Livermore National Laboratory under Contract DE-AC52-07NA27344

[15] http://www.epa.gov/OGWDW/uic/pdfs/support_uic_CO2_stewardshipforsiteclosure.pdf

[16] World Climate Change Report, 87 WCCR, 05/08/2009, BNA.

Gas that is injected for storage remains the property of the injector.[17] Injection of gas into property that the injector does not own is a trespass.[18] Pore space for such projects can be purchased or leased from the landowner, and/or the mineral estate owner, so long as it does not damage other persons.[19] Agreement with the mineral estate owner or lessee will generally be prudent in order to avoid later damage or trespass claims as there is ambiguity in some states regarding whether a mineral owner owns the pore space previously occupied by the minerals, natural gas or petroleum they have removed.[20] Liability for negligent operation of storage operations exists.[21]

Under many federal and state laws utility companies have eminent domain rights for utility facilities. This begs the question of whether CCS operations represent a utility facility under these statutes – if viewed as waste disposal, there is doubt. These statutes do not address the ability to exercise eminent domain rights over buffer zones that may be desirable because of the potential for gas migration. Buffer zones should be included because gas escape is a trespass; however, how such a buffer might be valued in an eminent domain action is unknown.

With regards to carbon sequestration the concept of condemnation poses several problems. CCS potentially involves large areas of land – hundreds of acres - depending upon the subsurface conditions and resulting available storage volumes.[22] The uncertainty over whether statutory authority to exercise imminent domain applies suggests an initial effort to negotiate and purchase rights. If injection requires approval from any landowner that could be affected, then it

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[17] Ellis v. Arkansas Louisiana Gas Co., 450 F. Supp. 412, 419 (D.C. OKL 1978) and many others

[18] Kuntz, The Law of Oil and Gas s 2.6, p.71

[19] Ellis, at 450 F. Supp. 412

[20] *Geologic CO2 Sequestration: Who Owns the Pore Space?*, 9 WY LR 98, 2009.

[21] In a recent case from Louisiana a jury awarded $9.2M to a petroleum company whose ability to exploit reserves was adversely impacted by improper maintenance and operation of a neighboring salt dome storage facility.

[22] *Separation and capture of CO2 from large stationary sources and sequestration in geological formations--coalbeds and deep saline aquifers. J Air Waste Manag Assoc. 2003 Jun;53(6):645-715*

will be necessary to secure consent from a potentially large number of people. Negotiation and condemnation will therefore impose high costs and long acquisition times.

As it will not be the intent (in most cases) to later retrieve the gas, there are interesting questions and serious unknowns regarding the rights and duties of the property owners later in time. Establishing ownership of CO_2 in perpetuity is a key part of this problem, especially given the vast amounts of time it will be sequestered. If there is no intent to recover perhaps there is no duty to protect and preserve the CO_2 or the associated surface facilities. If the entity that owned the CO_2 when it was injected disappears, then whether the CCS process is waste disposal or something else will be critical to understanding the on-going duties of the landowner. Any resolution of this issue will require legislation.

2. Enhanced Oil Recovery

Oil and gas leases typically contain the right to inject fluids to aid in the production of gas or oil, but not for disposal of waste. Leases and state laws often give the producer the right to "unitize" for secondary recovery allowing injection in various locations of a field. These enhanced recovery efforts are not necessarily designed to sequester CO_2 even if "acid gas" is used. Given the lease/contract rights these processes are probably not a good mechanism to examine the broader liability issues associated with CCS projects unassociated with oil and gas production.

As noted before liability for the injected materials, such as hydraulic fracturing fluid or acid gas, exists regardless of why these materials were injected. Contract or lease theories will apply and may be of value in the short-term until the normal statute of limitations runs. Beyond these theories liability is likely perpetual under federal environmental laws as these fluids will typically contain hazardous substances. As noted earlier, products liability theories may apply to the entity that produced the fluid if it harms third persons.

3. Waste Injection

Wastewater wells are subject to permitting by EPA and/or states. Failure to obtain permits or operate within the terms of a permit will make the operator subject to agency enforcement and citizen suits. Obviously the party injecting must have the legal right to do so; however, what those rights mean will be highly variable. In Chance v. BP Chemical, the Supreme Court of Ohio determined that the defendant committed a trespass when chemicals injected underground migrated under plaintiff's property for which no rights had been acquired. Even so, the proper evaluation of damages is very uncertain.

The court held that the surface owner's rights were not absolute, but were contingent on the reasonable and foreseeable use of their property.[23] According to the court, subsurface rights include the right to exclude invasions of the subsurface property that actually interfere with the property owner's reasonable and foreseeable use of the subsurface.[24] This would most certainly include harm to minerals or oil and gas resources leased by the landowner.

This sort of analogy would work well for CCS because landowner's that are not harmed by stored CO_2 would have no cause of action. It seems to follow that there would only be a cause of action after CO_2 specifically damages the health or property of a landowner – not for speculation that gas could potentially leak from geologic formations or interfere with access to minerals or oil and gas. Many courts would likely disagree and would find diminished value simply due to the trespass. Legislation, rather than litigation, is by far the best way to establish the rules in this arena.

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[23] Chance v. BP Chemical, 1995 WL 143827 (Ohio Ct. App 1995)

[24] Id.

4. Wastewater

In Cassinos v. Union Oil Co., the owners of a mineral estate sued defendant for damages when defendant injected wastewater into the mineral estate. The California Appeals Court rejected the defendant's claim that it should not be liable because the plaintiff did not establish the extent of damage to the mineral estate. The court held that there was substantial evidence the defendant's actions interfered with and damaged the mineral estate. Therefore, the defendant committed a trespass. The court also held that the plaintiff in the case could waive the tort claim and collect on an alternative theory of contract implied in law to recover the value of the use taken.[25]

From Chance (supra) and Cassinos, it is apparent that a cause of action is not likely to occur if there is no damage done. Interference with mineral rights should be a concern because CCS can displace subsurface gases and groundwater, which could damage mineral estates. The holder of a mineral estate or lease would have a cause of action along with the surface owner.

If the activity is allowed by statute it does not necessarily mean that the injector will be absolved of liability. In Tidewater Oil Co. v. Jackson, there were damages to plaintiffs' oil wells as a result of water flooding operations conducted by defendant on adjoining property. The Court of Appeals held that where defendant's water flooding activities were intentional and damage to wells on adjoining land was foreseeable, defendant was liable under Kansas law for damage to wells of adjoining leaseholders.

These findings were inconsistent with the administrative findings to the effect that the water flooding operations were carried on in a lawful manner. In the view the court took, it was unnecessary to reconcile the findings. It was sufficient that the water flooding activities were intentional and the consequences foreseeable. A legal claim was available, even though the

[25] Cassinos v. Union Oil Co., 14 Cal.App.4th 1770, 18 C (Cal App 1993)

flooding was lawfully carried on, because it caused substantial injury to the claimants.[26] This case is important because it highlights that regulations that allow CCS may not absolve the defendant of common law property law liability.

4. Water Law

It most of the Western US surface and groundwater is a public resource dedicated to the beneficial use of public agencies and private persons wherever they might make beneficial use of the water. (Texas is a bit different in that groundwater belongs to the landowner and is not subject to prior appropriation. That can result in significant fights between neighbors should one pump so much groundwater that a neighbor's well becomes dry. This law of the "biggest pump" has been mitigated through administrative processes such as conservation districts regulating the use of groundwater.[27]) Under the general western approach, including surface water in Texas, water quality and quantity are property rights subject to statutory and common law protections. The biggest difference between water and real property is that the protections available for water frequently exceed those available for real property.

The right of water use includes the right to cross the lands of others to place water into, occupy and convey water through, and withdraw water from the natural water bearing formations within the state in the exercise of water use right. Natural water bearing formations may also be used for the transport and retention of water.[28] Water authorities can inject water for later withdrawal with no payment for the pore space. The property rights of landowners or mineral estate owners/lessees do not include the right to control the use of water in the ground and cannot claim control of aquifers as part of their estate. Except for Texas, groundwater is part of "waters of the state" and either by Constitution or statute, the general assembly of each state

[26] Tidewater Oil Co. v. Jackson, 320 F.2d 157 (C.A. Kan. 1963)

[27] *Sipriano v. Great Spring Waters of America, et al., 1 SW3d 75* (Texas 1999)

[28] Board of County Com'rs of County of Park v. Park County Sportsmen's Ranch, 45 P.3d 693, 706 (Colo. 2002)

has control over the use and disposition of groundwater regardless of whether it is or is not directly discharged to a natural stream.

The law in most states prohibits the taking of private property for public or private use without the property owner's consent, but there are frequently exceptions which pertain to constructed water facilities.[29] For example many western state constitutions provide for access to the water source across the lands of others and further recognize and address the private right of condemnation for the construction of waterworks.[30] There is a requirement for compensation for use of another's land, but that does not extend to employment of natural water bearing subsurface formations on or within the landowner's property for the movement of appropriated water.[31] An applicant for a conditional decree to utilize available aquifer storage space must demonstrate that it will capture, possess, and control water lawfully available to it and without injury to other water rights.[32]

Water storage under a landowner's property is not a trespass if it does not inhibit the use, benefit, or enjoyment of property.[33] In Board of County Commissioners v. PCSR, LLP, PCSR proposed to store water in underground aquifers underlying approximately 115 square miles. The landowners claimed that storage of water underground in aquifers underneath their land would constitute a trespass. The Court held that it would not be a trespass and the project would not require the Landowner's consent or condemnation and the payment of just compensation under the provisions of Article XVI. The court, in applying Causby,[34] found that the project did not include construction of any facilities on or in the Landowner's properties and the

[29] Colo. Const. art. XVI § 7
[30] Colo. Const. art. II § 14
[31] Sportsmen's Ranch, at 45 P.3d 708
[32] Id.
[33] Sportsmens's Ranch, 45 P.3d at 708
[34] U.S. v. Causby, 328 U.S. 256 (1946) (ruled that property owner's rights were not unlimited with respect to airspace).

Landowner's had not alleged that the use, benefit, and enjoyment of their properties would be invaded or compromised in any way. Therefore, it was not a trespass.

The court stated that the General Assembly, in authorizing the use of aquifers for storage of artificially recharged projects further supplanted the Landowners' common-law property ownership theory.[35] The court found it "particularly [significant]" that:

> (1) [F]ederal patents to land do not include water, (2) ground water is not a mineral under the federal mining laws ..., (3) federal statutes as interpreted by the Supreme Court recognize [a state's] authority to adopt its own system for the use of all waters within the state in accordance with the needs of its citizens, subject to the prohibitions against interference with federal reserved rights, with interstate commerce, and with navigability of any navigable waters, (4) the right of prior appropriation applies ... to waters of the natural stream, including surface water and tributary ground water; (5) the property rights of landowners do not include the right to control the use of water in the ground, whatever the character of that water; and (6) the General Assembly has plenary control over the use and disposition of ground water that is not part of the natural stream.[36]

In sum, the holders of water use rights may employ underground as well as surface water bearing formations in the state for the placement of water into, occupation of water in, conveyance of water through, and withdrawal of water from the natural water bearing formations in the exercise of water use rights.[37] Consent or just compensation was not required because the plaintiffs did not have the right to restrict the defendant's use of the water that was done within regulations.

CCS presents a unique problem because the underground storage of CO_2 could potentially affect the flow and location of groundwater. This could occur because the process of physical trapping may displace naturally occurring water and other gases.[38] Any effect on water resources could pose potential liability if it limits access to water that has already been

[35] Id. at 703
[36] Id.
[37] Id. at 712
[38] Statement of Dr. Robert Burrus, Research Geologist, Enerby Resources Team U.S. Geological Survey U.S. Dep. Of the Interior Before the Subcommittee on Environement and Hazardous Materials House Committee on Energy and Commerce Hearing on "Carbon Sequestration: Risks,

appropriated to beneficial use. Physical displacement of groundwater can also have adverse practical impacts on private owners and utilities. As a result it will normally be prudent to evaluate whether on-site groundwater wells, especially those used by public water systems, will be disrupted by CCS operations.

In most places a water right includes the right to a particular quality as well as a particular quantity of water. These cases are typically framed in the context of deprivation of quantity but these water rights are also protected from activities of another that injure the quality of a water right.[39] Therefore, if water quality is affected by the precipitate that hopefully forms from the geochemical reactions intended as part of CCS operations the owner of that water could have a cause of action against the entity injecting and the owner of the gas injected. Historically such interference involved the discharge of mine and other wastes into the stream but there is no reason to believe the result would be different with CCS.[40]

III. Regulation

A. EPA UIC Rulemaking

The UIC Program regulates underground injection under five different classes of injection wells, depending on the type of fluid being injected, the purpose for injection, and the subsurface location where the fluid is to remain. States are allowed to assume primary responsibility for implementing the UIC requirements in their borders, as long as the state program is consistent with EPA regulations and has received regulatory approval. Injection operators are required to provide financial assurance in case they cease operations, with the level of assurance a function of the estimated cost of plugging and abandoning the injection well. If there is a violation of a UIC permit, an enforcement action may be brought by the EPA

[39] 2A COPRAC § 76.11

[40] Game & Fish Comm'n v. Farmers Irr. Co., 162 Colo. 301, 426 P.2d 562 (1967); Wilmore v. Chain O'Mines, 96 Colo. 319, 44 P.2d 1024 (1934).

Administrator or the applicable state agency. Violators may be subject to administrative orders, civil penalties, and criminal penalties. The scope of the UIC statute is contamination of drinking water, and under its current application to CO_2 storage, the UIC Program gives more limited treatment, if any, to other harms to human health, the environment, and property.[41]

While there are requirements for constructing and monitoring injection well operation, there are no federal requirements for monitoring actual movement of fluids within the injection zones, nor are there requirements for monitoring in overlying zones to detect leakage with the exception of specific class I hazardous wells, where this monitoring can be mandated.[42]

On July 15 2008, the EPA proposed a rulemaking package that would regulate geologic sequestration of carbon dioxide under the UIC. The proposed rules would create a new category of UIC well (Class VI) designed specifically for injection of CO2 into geologic formations. The proposal includes detailed technical requirements for characterizing the scope and suitability of the target formations, assuring that the injection zone will not affect any actual or potential source of drinking water, monitoring and reporting on well conditions during and after the sequestration is complete, and requiring as part of well permit applications plans for 50 years of post-injection monitoring.[43]

The proposed rules do not directly address air quality issues. The Class VI CO_2 injection well requirements are designed to assure that there are no significant releases of CO_2 or contaminants in the CO_2 into the ambient atmosphere. The EPA declined to classify CO_2 as a hazardous waste but the proposed rules place a burden on the permittee to assure that the CO_2 does not contain impurities that would trigger RCRA hazardous waste management

[41] Craig A. Hart, *Advancing Carbon Sequestration Research in an Uncertain Legal and Regulatory Environment: A Study of Phase II of the DOE Regional Carbon Sequestration Partnerships Program*, Discussion Paper 2009-01, Cambridge, Mass.: Belfer Center for Science and International Affairs, January 2009.

[42] Regulating the ultimate sink: managing the risks of geologic CO2 storage. Page 3479

[43] http://www.epa.gov/ogwdw/uic/wells_sequestration.html

requirements. The risks associated with this classification are manifest. Injection of hazardous waste is highly regulated and would likely bring a CCS project to a screeching halt.

None of this overrides the applicable provisions of CERCLA or RCRA. To the extent there are hazardous substances released from the sequestration process liability under CERCLA may be present.[44] Likewise if materials injected are hazardous waste the daunting permitting and corrective action provisions of RCRA and the state programs will apply.

As an example, EPA issued orders under RCRA to require management of propane that had leaked from an underground distribution system. In EPA's view, the moment the propane leaked from the distribution system it was a waste and presented a hazard. Depending upon the factual setting, CCS operations could find themselves in the same situation.

B. State Regulation

In the absence of federal action on the carbon sequestration issue, many states are in the process of enacting their own regulations. Some examples follow:

1. Wyoming

House Bill 89 (created Wyoming Statute § 34-1-152 and amended Wyoming Statute § 34-1-202) addresses the ownership of Pore Space. The Bill establishes that the surface owner owns pore space underneath the surface estate and that the pore space is conveyed upon the conveyance of the surface, unless the space has been previously conveyed or is explicitly excluded in the surface conveyance (in the same manner as a mineral interest). In addition, legal requirements for notice to surface owners and/or mineral interest owners shall not be construed to require notice to the pore space owner unless the law specifies that such notice to the pore space owner is required. The statute expressly recognizes the dominance of the mineral estate

[44] http://www.bbclimatechange.com/climate_change/2008/07/epa-releases-pr.html

and does not alter the common law as it relates to the rights of the mineral estate. The bill states explicitly that it does not affect the common law regarding the dominance of the mineral estate.[45]

House Bill 90 (effective July 1, 2008; created Wyoming Statute §§ 30-5-501 and 35-11-313 and amended Wyoming Statute § 35-11-103(c)) mandates UIC permit for GCS. It makes a clear distinction from EOR. It instructs the Wyoming Department of Environmental Quality to establish and issue permits to new "sub-classes of wells" within the UIC program and to regulate well standards, bonding and monitoring. The bill requires the DEQ to create an advisory board and rules to expand the UIC program to include carbon sequestration. Under the bill, a working group including the supervisor of the oil and gas commission, the state geologist, and the director of the DEQ will set bonding procedures. Jurisdiction subsequent extraction of sequestered carbon dioxide rests with the Wyoming Oil and Gas Conservation Commission. The bill does not impact the oil and other mineral interest owners' right to drill or bore through sequestration sites, nor does it include within its scope the regulation of enhanced oil recovery operations using carbon dioxide.[46]

Like HB 89, Wyoming's carbon capture and sequestration legislation recognizes the continuing dominance of the mineral estate. § 30-5-501 states specifically that the carbon sequestration legislation enacted by § 35-11-313 shall not "affect the otherwise lawful right of a surface or mineral owner to drill or bore through a geologic sequestration site" so long as the drilling is conducted in conformity with rules for protecting the sequestration site against the escape of CO_2.[47]

[45] Id. at 143-45

[46] Delissa Hayano, *Guarding the Viability of Coal & Coal-Fired Power Plants: A Road Map For Wyoming's Cradle to Grave Regulation of Geologic CO2 Sequestration*, 9 *Wyo. L. Rev*. 139, 145-49 (2009)

[47] Id.

2. Oklahoma

Senate Bill 1765 (May 2008) was a proposal that required the development of GCS permitting regime and transferred ownership of wells to state and released owners from liability 10 years after closure. The Bill that was passed, however, was relatively disappointing. It mandated a task force to report to the Governor with GCS permitting recommendations by December 2008 (extended to December 2009) and is modeled based on the IOGCC model statute.[48]

3. Kansas

Under HB 2419 (2007), GCS rules were supposed to be developed by July 2008 (draft in progress). Under the Bill, a state GCS fund would pay long-term GCS related monitoring and remedial activities. It also exempts GCS property and any electric unit utilizing GCS from taxes for 5 years. Finally, it allows for accelerated depreciation of GCS equipment.[49]

4. Washington

ESSB 6001, passed April 17 2008. It codifies the emissions-reduction goals and policy recommendations for the state. The bill also sets an Emissions Performance Standard (EPS) that limits electric utilities' ability to sign new or renewed long-term contracts with power plants whose greenhouse-gas emissions exceed those of a modern natural gas-fueled power plant. The bill essentially ends construction of pulverized coal plants to serve Washington loads, makes the price of IGCC power reflect some of its emissions disposal costs, and jumpstarts the process toward a comprehensive greenhouse-gas emissions reduction plan for the state.[50]

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[48] de Figueiredo MA, Reiner DM, Herzog HJ. Framing the long-term in situ liability issue for geologic carbon storage in the United States. Mitigation Adapt. Strat. Global Change 2005;10:647-57.

[49] Melisa F. Pollak ,Humphrey Institute of Public Affairs, Big Sky Carbon Sequestration Partnership Annual Meetin. Oct. 28, 2008

[50] NW Energy Coalition, April 19, 2007. www.nwenergy.org/publications/fact-sheets/6001%20FINAL%2

Will Water Issues/Regulatory Capacity Allow or Prevent Geologic Sequestration for New Power Plants?

A Review of the Underground Injection Control Program and Carbon Capture and Storage

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Executive Summary

International concern over global climate change has spurred a search to identify ways to reduce greenhouse gas (GHG) emissions. Of the six gases comprising greenhouse emissions, carbon dioxide (CO_2 - "carbon") emissions far exceed the other five in the amount emitted.[1] The U.S. is considering a number of voluntary options for an 18 percent reduction in CO_2 emissions by the year 2012. One technology receiving serious consideration by the international agencies, Congress, states, and the Bush Administration is carbon capture and storage (CCS) or sequestration[2]

First the carbon dioxide from a power plant would have to be separated and removed from the power plant. Carbon sequestration really refers to the geologic storage in deep geological formations below the earth's surface. Carbon dioxide injection has been used for several years in enhanced oil recovery operations. Through government and private partnerships, the U.S., through the Department of Energy (DOE), is evaluating the viability of long-term CCS by conducting demonstration and validation testing of CCS pilot projects. APPA supports carbon storage demonstrations through the DOE and FutureGen to determine if the injection of CO_2 is safe and effective as a mitigation measure.

The CCS issue is of considerable import to the electricity/power plant sector which the U.S. DOE considers to be one of the largest emitters of CO_2, accounting for 38 percent of CO_2 emissions among all energy sectors.[3]

While the U.S. DOE is pushing aggressively to deploy CCS for full-scale commercial use, there are a number of technical, regulatory, and policy issues related to long-term CO_2 storage or geosequestration that remain to be studied and resolved.

The U.S. Environmental Protection Agency (EPA) has regulatory authority over injection of wastes into wells through the Underground Injection Control program (UIC) created by Congress under the Safe Water Drinking Act. Congress specifically created the program out of concern for the protection of underground drinking water sources. Although the UIC program has established five classes to address various injection well activities, the Agency currently does not have a regulatory framework by which to regulate CCS activities. U.S. EPA has recently issued guidance to assist its regional offices and state regulators with permitting and operational decisions related to CCS pilot projects.

The U.S. EPA has classified CCS pilot projects as Class V experimental technology; however, the regulatory framework for Class V wells is insufficient to provide the necessary safeguards to ensure protection of groundwater sources. Therefore regulators have relied on the stringent requirements established for Class I hazardous waste wells, which includes the requirement that operators demonstrate no-migration of injection fluids (which would include CO_2) for a period of 10,000 years.

[1] U.S. DOE National Energy Technology Laboratory, *Carbon Sequestration Program Environmental Reference Document ("NETL Reference Document")*, Aug. 2007, at 1-2. See also, Electric Power Research Institute, *Electricity Technologies in a Carbon-Constrained World*, ("Electricity sector is responsible for 1/3 of U.S. CO_2 emissions").

[2] Sometimes sequestration is also referred to as geosequestration.

[3] *NETL Reference Document*, at 1-2.

In summary, there are major limitations in the technical, regulatory, and administrative requirements of the UIC program that appear to preclude, in the short term, commercial-scale sequestration of carbon in non-oil and gas sites in large parts of the country. These limitations are important for utilities and policy officials to evaluate as they consider CCS projects. For electric utilities that wish to build additional generation to meet the needs of their communities, the challenges include very difficult issues.

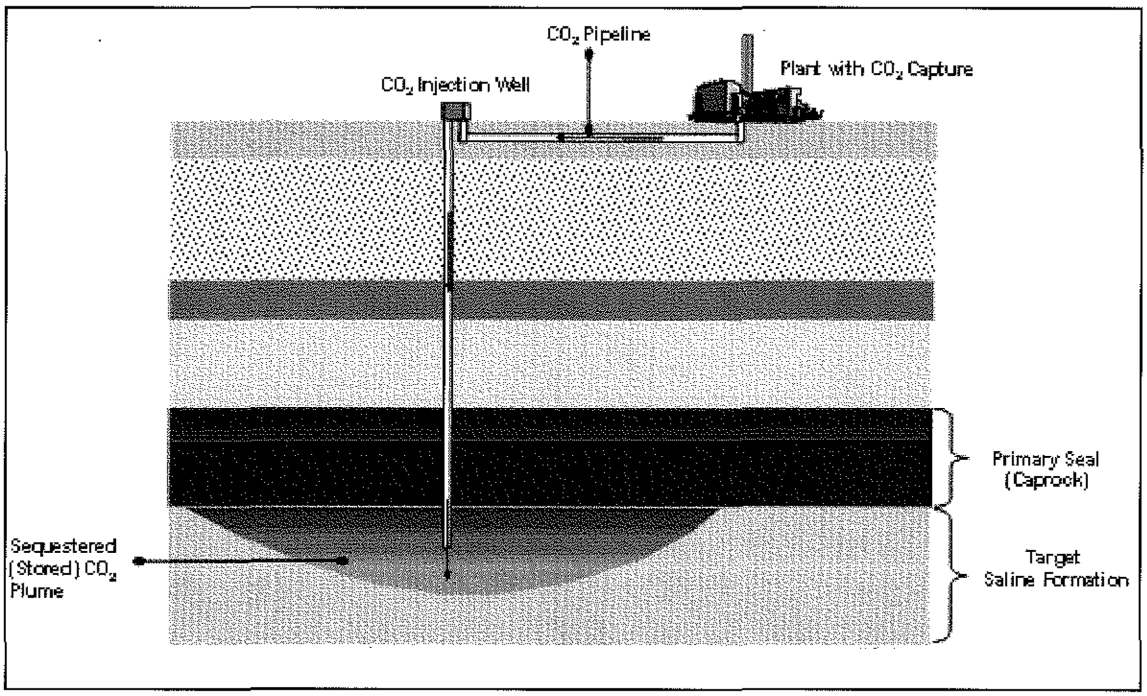
APPA recommends that States and Public Utility Commissions consider and investigate the several limitations identified in this paper prior to mandating CCS as a part of permit approval. APPA also recommends working with the U.S. EPA on the cross-cutting and multimedia regulatory issues as the Agency moves forward towards determining the best regulatory framework for CCS.

Introduction

What is the Issue and Why does it Matter to Utilities and Municipal Government?

Policy officials and scientists alike, searching for viable ways to reduce carbon dioxide (CO_2) emissions, have identified carbon capture and storage (CCS) [4] as a promising technology. This technology separates CO_2 from emissions of large stationary sources like power plants and injects the captured CO_2 deep into the earth. Figure 1 gives a simple picture of this technology. The Intergovernmental Panel on Climate Change (IPCC) has identified CCS as a way of achieving overall reductions in greenhouse gas emissions.[5] This enthusiasm is shared by the U.S. government. The U.S. Department of Energy (DOE) is engaged in research and development of various CCS technologies to determine the viability of full scale deployment of CCS by the year 2012. The U.S. DOE is leading the Regional Carbon Sequestration Partnerships to conduct research and development of CCS and supporting small scale demonstration and validation pilot projects to determine the potential of this technology.

Figure 1: Diagram of a Carbon Capture and Storage Operation[6]



The benefits of reducing CO_2 emissions through CCS must be balanced against the potential increased risks of groundwater pollution from CCS. Utilities provide water and power to their

[4] Carbon Capture and Storage is also referred to as Carbon Geologic Sequestration.

[5] Intergovernmental Panel on Climate Change, *Special Report: Carbon Dioxide Capture and Storage, Summary of Policymakers, 2005.*

[6] U.S. DOE National Energy Technology Laboratory, *Carbon Sequestration Program Environmental Reference Document*, Aug. 2007, at 3-53 Fig. 3-22.

communities and rely on available water supplies to produce power. Utilities are uniquely positioned and therefore must understand the potential promise and limitations of CCS.

The potential trade-offs will tighten in the future as demand increases for power, water, and GHG reductions. According to EPA, ground water systems account for 91 percent of the total public drinking water systems in the U.S., serving 36 percent of the U.S. population.[7] Demand for drinking water increases with population growth, number of households, and manufacturing. While conservation has reduced this need for some new sources, groundwater levels in many parts of the U.S. are declining due to increased pumping.[8] Meanwhile, the demand for electric is expected to increase by 39 percent from 2005 to 2050,[9] requiring new capacity. If new power plants use CCS as some states are considering, underground drinking water sources will face pressure from both power and water needs.

The American Water Works Association (AWWA) and the American Public Power Association (APPA) commissioned this paper to consider the drinking water and groundwater issues with CCS and to identify the regulatory and technical hurdles that might minimize opportunities for CCS. More than 1,000 of the nation's municipalities provide electricity to homes; businesses and factories also manage many water utilities providing drinking water to residential, industrial, and commercial customers.

There are several cautions to assuming a seamless fit between current regulation and CCS. First, the existing regulations and regulatory program arose over 20 years ago, long before CCS was envisioned. Since CCS does not fit neatly into the existing program for power plants, the EPA is still in the process of crafting a regulatory approach. Second, for CCS to have a meaningful impact on U.S. emissions, the volume of CO_2 to be injected underground will dwarf current amounts by 10 to 20 times. While the nation has the ingenuity to tackle this challenge, it will require investing in technical skills, data, research, and education both in the private sector and in regulatory agencies. Currently, regulatory agencies do not have the capacity to review and permit CCS at any significant level. To illustrate this issue, this paper reviews the current UIC program, its current implementation, the current regulatory framework for CCS, and the skill shortages states and EPA will face if CCS moves toward full-scale implementation. Finally, this paper highlights the major limitations for CCS that power plant and water utility managers should consider.

What is Underground Injection?

Underground injection involves the use of simple or complex technology to inject fluids into the earth most often for purposes of waste disposal or extraction of fossil fuels and minerals. Wells regulated by the EPA include common shallow septic tank systems to highly-engineered, large volume systems that inject materials more than a mile underground. While shallow wells may only dispose of a few gallons per day, large disposal systems may each day pump the volume of an Olympic-sized swimming pool.

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[7] U.S. EPA, *Factoids: Drinking Water and Ground Water Statistics for 2005*, Dec. 2006.

[8] Source: U.S. Geological Survey at http://ga.water.usgs.gov/edu/gwdepletion.html.

[9] Energy Information Administration, *Annual Energy Outlook 2007*, Feb. 2007, at 82.

What is the Underground Injection Control (UIC) Program?

Congress and EPA established the legal framework for regulating underground disposal over 30 years ago. Congress established the UIC program as part of the Safe Drinking Water Act (SDWA) of 1974 providing EPA with the authority to regulate underground injection activities to ensure the protection of the nation's underground sources of drinking water. Almost all U.S. public water systems rely on some groundwater for drinking water.[10] Congress strengthened the regulatory requirements for hazardous waste UIC disposal in 1984. In the last 20 years, there have not been significant changes to the UIC program's legal authority.

Congress intended for the UIC program to be administered by states due to the large number of wells and to the tradition of local control and regulation of drinking water. As such, the SDWA allows states to submit an application to EPA for primary enforcement or "primacy" for each part, or "class," of the program. EPA can delegate primacy to a state, U.S. territory, or a federally recognized Native American tribe. The UIC program may be executed by the EPA, the state, or both under four separate scenarios:

1) EPA administers the program for all well classes within a state if the latter chooses not to apply for primacy;

2) a state is delegated primacy for all five classes;

3) a state has primacy for Class II (oil and gas) wells only; or,

4) a state has primacy for all classes except Class II oil and gas wells.

EPA has delegated primacy for the entire program to 34 states and three territories, shares responsibility with six states, and retains full responsibility in ten states. The ten states for which EPA has primacy are: Arizona, Hawaii, Iowa, Kentucky, Michigan, Minnesota, New York, Pennsylvania, Tennessee, and Virginia. These states have determined that committing state resources to run the program is not a high priority.

How does EPA Regulate Underground Injection?

EPA established five classes of injection wells (Class I, II, III, IV, and V) under the UIC program based upon how the well is used, constructed, and operated.[11] The classes provide a consistent way for EPA to apply technical standards to similar activities to ensure the protection of underground drinking water and human health.

The classes are ranked by their potential hazard. Class I wells are for the largest volume and the most hazardous wastes. Class V wells are for shallow septic systems, dry wells, and low volume systems. Most UIC wells are either Class V, Class I, or Class II wells.

All underground injection wells must have a permit. For each class, EPA has established minimum technical standards, public participation, and a permitting process review that

[10] See EPA website, http://www.epa.gov/safewater/uic/whatis.html.
[11] 40 CFR Part 144.6.

states must include in their permitting process. With approximately 834,000 wells across the U.S.,[12] the UIC program is one of the largest environmental permitting programs.

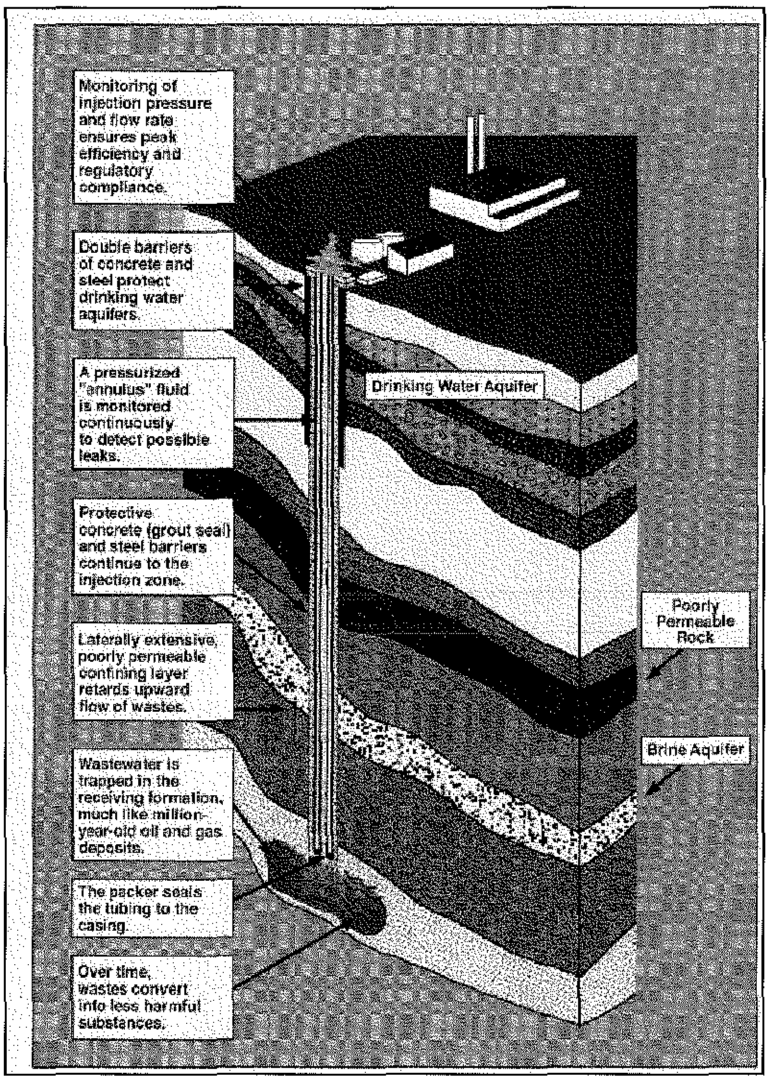
[12] U.S. EPA, *Factoids: Drinking Water and Ground Water Statistics for 2005*, Dec. 2006; http://www.epa.gov/safewater/uic/classes.html.

What are the Five Classes of Injection Wells under the UIC Program?

Class I Injection Wells

Subject to the most stringent regulations, Class I wells include industrial hazardous, nonhazardous, and municipal sewage waste. Class I wells inject wastes deep into rock formations that are located beneath the lowest underground sources of drinking water[13] and that are capped by an impermeable rock formation between the injection zone and drinking water sources above.

Figure 2: Diagram of Class I Well[14]



[13] Class I hazardous wastes are injected to depths anywhere from 1,700 feet down to 10,000 feet below the earth's surface.

[14] U.S. EPA Office of Water, *Class I Underground Injection Control Program: Study of the Risks Associated with Class I UIC Wells*, Mar. 2001, at 11.

In 1984, Congress tightened Class I requirements by instituting a no-migration standard for disposal of hazardous waste via injection and creating a petition process by which operators must obtain approval to continue hazardous waste injection operations. Specifically, Congress prohibited injection of untreated hazardous wastes unless it is demonstrated that the waste has been treated to be non hazardous or unless the waste will not migrate out of the injection zone or contaminate drinking water for at least 10,000 years.[15] Because of the large volume of wastes injected, Class I injection is economical if it can show a "no migration" of the waste. Well operators, filing the petition to operate such wells, must accomplish this demonstration by modeling waste behavior underground.[16]

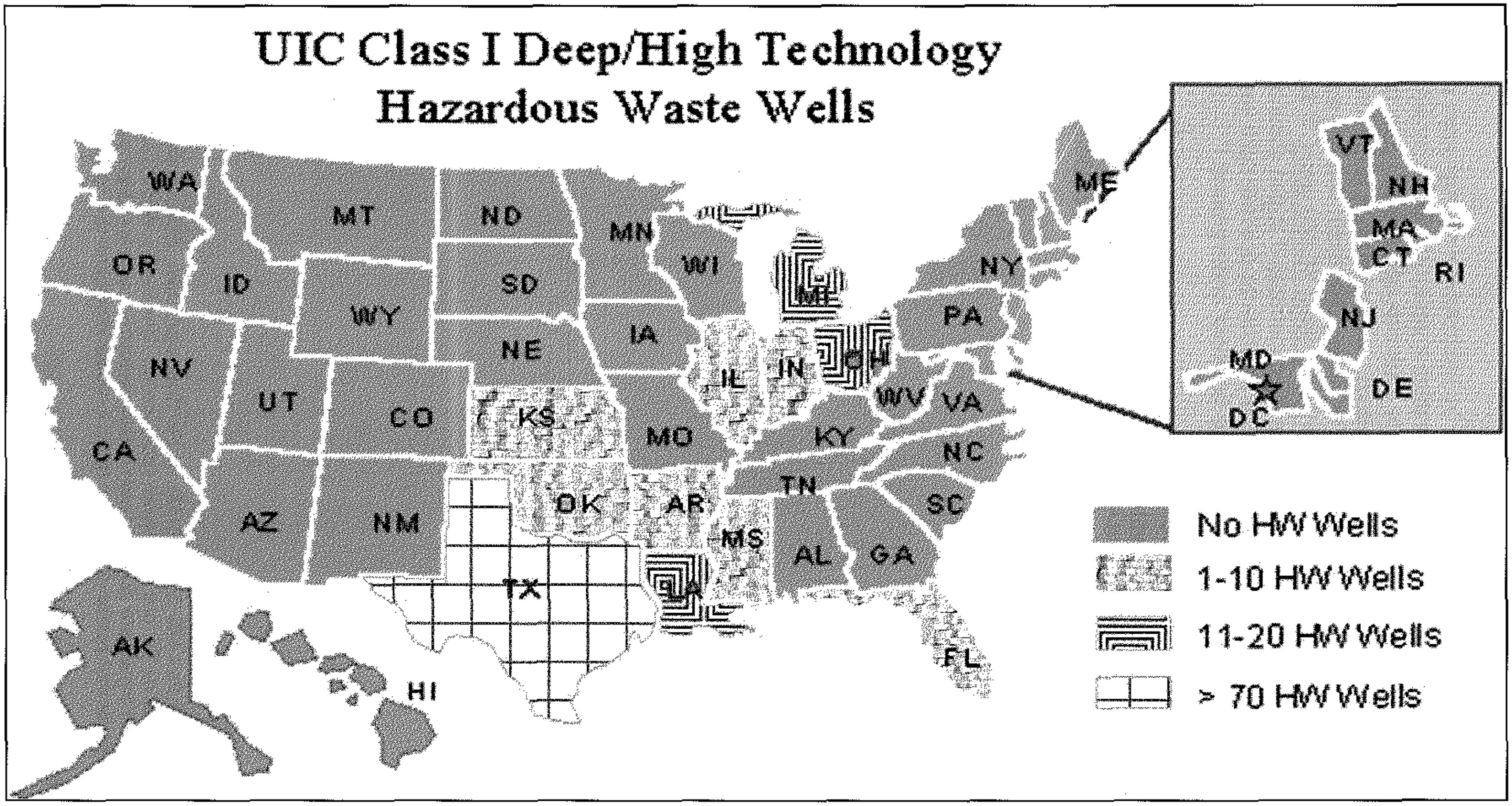
While there are a total of 529 Class I wells nationwide, there are only 163 Class I hazardous waste wells nationwide. Most Class I wells are found in Texas and Louisiana. Class I wells are banned in Missouri. The map below shows the location of Class I hazardous waste wells in the U.S.[17] As the map below shows, only 11 states have active Class I hazardous waste wells.

[15] NRDC v. EPA, 907 F. 2d at 1158

[16] RCRA, Section 3004, 40 CFR Part 148 (53 FR 28118). In the final regulations, EPA explained that 10,000 year requirement is based on ensuring for long term waste confinement. Specifically, demonstrations that can show no-migration over a 10,000 year period are likely to result in containment for an even longer period of time. Additionally, confinement for that period of time can result in waste immobilize due to geochemical transformation.

[17] See EPA website, http://www.epa.gov/safewater/uic/classi.html.

Figure 2: Hazardous Waste Wells in the U.S.



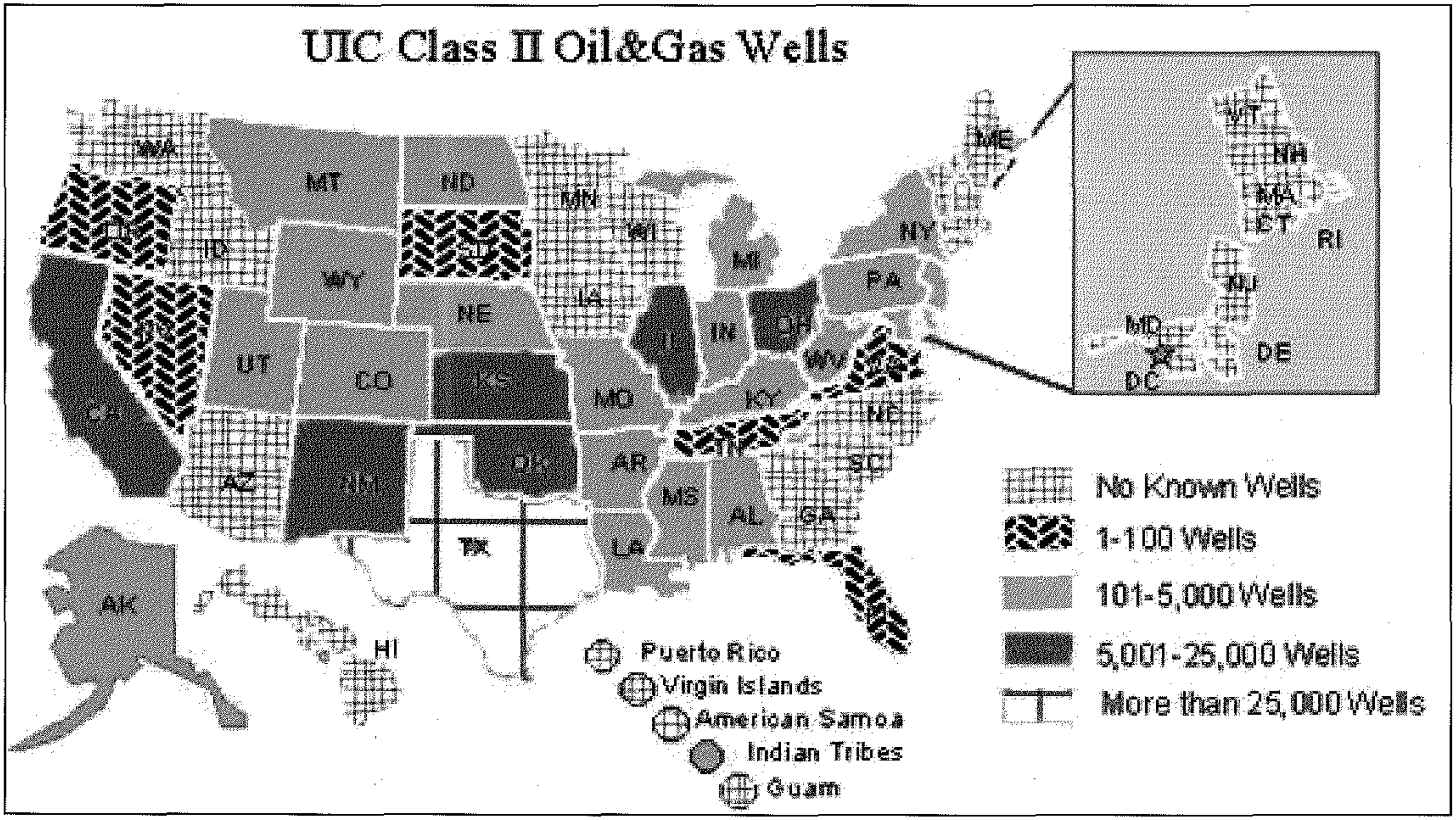
There are 366 nonhazardous Class I waste wells in 19 states. Nonhazardous Class I waste wells are required to comply with the same technical standards as hazardous waste wells.

Class II Injection Wells

Oil and gas production facilities use Class II wells to inject fluids to pump hard-to-get oil and gas deposits to the surface. The recovered crude oil and natural gas comes to the surface mixed with salty water and other impurities. States require injection of this salty water underground so as not to pollute drinking water. Class II wells must comply with strict construction and operating standards and are often similar in construction to Class I deep wells. There are approximately 167,000 Class II wells, predominantly found in the southwestern U.S. The map below shows the location of Class II wells in the U.S.[18] Twenty-two states do not have any Class II wells.

[18] See EPA Website, http://www.epa.gov/safewater/uic/classii.html.

Figure 3: UIC Class II Oil & Gas Wells in the U.S.



Class III and Class IV Injection Wells

Class III wells typically involve using injection of fluids to extract minerals. Mining operations for salt, sulfur, and uranium rely heavily on injection using Class III wells. Class III wells have minimum standards for which operators must comply, including required casing and cementing of wells to prevent the migration of fluids into drinking water sources, a prohibition on injection of fluid between the outermost casing and well bore, and required integrity tests of well casings every five years.

In Class IV wells, hazardous waste is injected directly into or above underwater drinking water. Although Class IV wells, like Class V, generally involve shallow wells, EPA created a separate class for injection activities that present a heightened risk. Class IV wells have been banned except in very narrow circumstances.

Class V Injection Wells

Most injection wells in the U.S. are Class V wells with an estimated 650,000 Class V wells in the nation.[19] Class V wells inject nonhazardous waste into or above underground drinking water and occur in a variety of residential and commercial settings including sewage disposal, aquifer recharge, and mineral recovery. Class V wells include advanced systems used by industry for wastewater disposal as well as less advanced types found in septic systems, cesspools, and agriculture drainage wells.

Injection activities that do not fit into the other classes - like CCS - are called Class V wells. Experimental technologies that are in the demonstration phase are classified as Class V injection.[20] Although there are no federal requirements that specifically address Class V experimental technology wells, over the years EPA has issued guidance to cover certain experimental technologies. Notably, EPA issued guidance in 1983 clarifying that technologies in the experimental phase which would have otherwise fallen under another UIC program-class based upon well function, may be reclassified into one of the five classes once the technology has advanced for commercial use. However, the technology remains under Class V until proven for commercial use and it is shown that the technical standards of the other class would provide sufficient protection of underground drinking water and human health once the new technology is deployed for commercial use. If the technical standards of the other classes are unable to provide sufficient protection, the new technology remains under Class V until EPA adopts protective technical standards.[21]

EPA did not establish technical standards for Class V wells until the 1990s. Because of the diversity and sheer number of these wells, EPA did not set minimal technical standards for Class V wells. Since EPA finished the Class V rule over 10 years ago, EPA has not issued major policy changes to the program.

[19] U.S. EPA, *Factoids: Drinking Water and Ground Water Statistics for 2005*, Dec. 2006.

[20] See, Underground Injection Control (UIC) Regulations as amended, 40 CFR Part 146.05(e), Aug. 27, 1981 (46 FR 43156), and 40 CFR Part 146.03, Feb. 3, 1982 (47 FR 1416).

[21] Victor J. Kimm, *Memorandum: Appropriate Classification and Regulatory Treatment of Experimental Technologies. Ground-Water Program Guidance No. 28 (GWPG #28)*, May 31, 1983.

How Does CCS Fit into the UIC Program and Why Does this Matter to Electric Utilities?

Congress and EPA did not envision sequestration of carbon dioxide when they established the program for the chemical industry over 30 years ago so no federal regulatory framework exists to regulate CCS activities specifically. Yet, EPA has considered how CCS is regulated under the UIC program. In 2006 EPA determined that CCS activities are "underground injection" and that SDWA mechanisms are sufficient to regulate and to permit pilot projects. As a result, EPA issued a directive that CCS pilot projects are to be permitted as Class V experimental technology wells.[22] This policy directive might be supplanted by an EPA rulemaking in 2008.

Since there are no federal requirements governing Class V experimental technology wells, there has been a lot of confusion and uncertainty. In March 2007 EPA issued guidance for permitting and operation of CCS pilot projects as a Class V experimental technology wells.[23] This guidance for CCS pilot projects tries to straddle between the current legal framework and the environmental standards necessary to inject a large volume of carbon dioxide safely.

Legally, EPA confirms that Class V is "the best mechanism for authorizing pilot GS project,"[24] and that Class V general permitting and public participation requirements apply. The permits can remain in effect as long as needed to cover the timetable of project goals and may be modified or extended to alter the goals or timetable, but cannot exceed state or federal permit limits.

As a counterpoint to the flexibility inherent in a Class V permit, the guidance then lays out why states should consider more stringent permit conditions in the CCS Class V permit. EPA emphasizes throughout the guidance that protection of underground drinking water and human health is the overriding concern. EPA lays out a number of considerations for regional and state directors to take into account for purposes of permitting and operation, including:

- Siting considerations;
- Consideration of the underground area affected by the injection;
- Injection well construction;
- Injection well operation and monitoring program considerations; and,
- Site closure.

UIC program directors are also encouraged to consult with deep well experts including Class I and Class II directors to ensure appropriate standards are applied for CCS pilot projects.

However, EPA stops short of recommending CCS pilots have all the features of Class I permits, although UIC directors can opt for Class I requirements. The 2007 EPA guidance stresses that the primary goal of pilot projects is for EPA, the states, and well operators to collect and share data to better understand how CO_2 reacts and moves underground, as well as

[22] Cynthia C. Dougherty, *Letter to State Regional UIC Contacts re: CCS pilot projects*, U.S. EPA Office of Water, Jul. 5, 2006. http://www.epa.gov/safewater/uic/pdfs/memo_wells_sequestration_7-5-06.pdf

[23] *UICPG # 83*. http://www.epa.gov/safewater/uic/pdfs/guide_uic_carbonsequestration_final-03-07.pdf

[24] *UICPG # 83*, at 6.

understanding what the risks are associated with CO_2 injection. To determine how best to manage commercial scale CCS injection operations, the guidance suggests EPA regional and state directors adopt a more flexible approach in approving permits and identifying permit conditions to allow operators to "achieve project objectives."[25]

How have States Regulated CCS Pilots?

EPA and the states have looked to Class I and II regulations for permit conditions for CCS pilots because of the depth of injection and the larger volume of CO_2 injected. Today CO_2 is currently is being injected to recover oil and gas in wells subject to Class II well requirements. Some CCS pilots have occurred in oil and gas formations in Class II wells.[26] In the few cases to date, states have granted Class V permits for CCS pilots sequestration with many - if not all - of the technical requirements for a Class I permit.

What are the Specific Class I and II Technical Requirements?

The technical requirements for Class I and II wells include siting, well construction, operation, reporting, monitoring, permitting, financial assurance, and closure standards. The regulatory system is designed to minimize leaks into drinking water formations as waste and fluids are pumped down through these layers and after they are put underground.

Siting

Class I permits require three separate hydrogeologic investigations to permit a deep injection well: reviewing the geology of the area, conducting an area of review study, and finally submitting a no migration petition.

In the geologic study, permit applicants must show that the area is geologically stable; the area is not seismically active now and has not had earthquakes in recent geologic time. The formation must have suitable room to store the injected wastes and thick enough to dissipate the pressure without cracking the confining layer. The geologic study must also show the area around the well is free of vertical faults that could allow the injected fluids to migrate up to drinking water layers. Finally, the geologic study must also demonstrate that the injection layer's rocks are chemically compatible with the waste. [27]

The second study is the Area of Review. In this study, well operators must investigate all wells in the area that penetrate the injection or the confining layer. Operators must demonstrate that all of these wells are sufficiently capped and closed to prevent migration out of the injection layer. Under federal regulations for Class I hazardous waste wells, the Area of Review is defined as either a 2 mile radius from the well or to the zone of endangering influence on underground drinking water, whichever is a greater distance. States require larger Areas of Review; Texas, for example, uses a 2.5 radius for its Area of Review. For nonhazardous waste, the Area of Review can be a low as ¼ of a mile.[28]

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[25] *UICPG #83*, at 3.

[26] According to U.S. DOE, there are at 75 oil reserve carbon sequestration projects in the following states: Arkansas, Colorado, Louisiana, Oklahoma, and Texas. See, U.S. DOE National Energy Technology Laboratory, *Carbon Sequestration Program Environmental Reference Document*, Aug. 2007, at 3-60.

[27] U.S. EPA Office of Water, *Class I Underground Injection Control Program: Study of the Risks Associated with Class I Injection Wells*, Mar. 2001, at 18.

[28] Ibid, at 19.

One of the biggest challenges for Class I operators is to demonstrate no-migration of waste for at least ten thousand years. This demonstration requires computer modeling, knowledge of regional geology, and detailed geologic information of the area around the well. Small faults or buried channels can create a connection between deep formations and shallower drinking water sources. Injecting fluids also changes the volume and pressure underground, possibly activating dormant faults. Permit applicants must also search for abandoned wells that might connect the injection zone with upper layers.

Construction

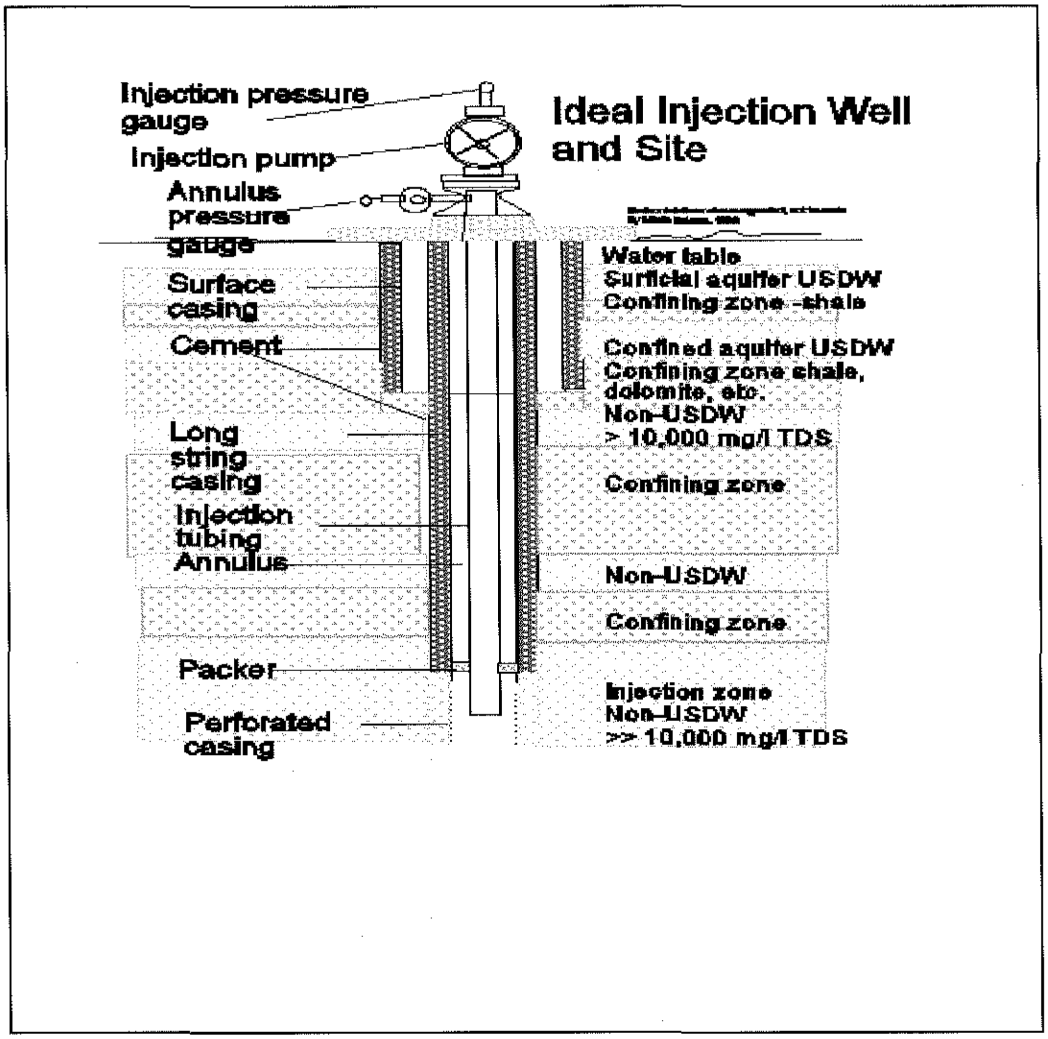
Operators prevent leaking by wrapping their wells in impermeable casing. Operators of enhanced recovery and hydrocarbon storage wells are required to case and cement the wells to prevent migration of fluids into underground drinking water. Specific casing and cementing requirements are determined by the state on a case-by-case basis; however, as part of that process they must take into account injection zone depth, depth of the bottom of all drinking water formations, injection pressures, and the nature of fluids to be injected.[29]

The well has essentially three walls so that breaching one still contains the waste. As shown in Figure 4, the injection tubing transports the waste to the injection zone. It is made of corrosion-resistant material and it is surrounded by the long string casing. This casing is sealed at the bottom by the packer and at the top by the well head. Operators must pressurize this space between the long string casing and the injection tubing to monitor for and to prevent leaks. Finally, the outermost wall, the well casing, supports the well structurally. Operators must maintain mechanical integrity of the well until plugged and abandoned.[30]

[29] 40 CFR Part 144.28(e)

[30] 40 CFR Part 144.28(f)

Figure 4: Diagram of Class I Well Technology[31]



Monitoring

Monitoring requirements include monitoring of the well and other formations. Class I well operators are required to analyze injection fluids to identify fluid characteristics, to use continuous recording devices to monitor injection pressure, flow rate, and volume, and to monitor for any leaks into drinking water with monitoring wells.[32] Operators also minimize any leaks by carefully watching injection pressure. If there is a leak in a well, the pressure in the well will drop as the fluids escape out of the circumference. Regulations require well operators to use continuous recording devices to monitor injection pressure, flow rate, and volume.[33] To demonstrate mechanical integrity, well operators must show that fluids will not

[31] Source: U.S. EPA website: http://www.epa.gov/safewater/uic/idealwel.html.

[32] 40 CFR Part 144.28(g)(1).

[33] 40 CFR Part 144.26(g)(1).

leak while traveling to the well, will not leak out of the well as it is injected, nor move into underground drinking water once injected into the deep rock.[34] The UIC program requires mechanical integrity demonstrations at least once every five years for both Class I and Class II wells.[35]

Class I operators are also required to develop approved ambient monitoring programs as determined by the Program Director to protect against fluid movement out of the injection zone. Monitoring programs are based upon a site-specific assessment and must include at a minimum annual monitoring for injection zone pressure.[36] The Director may also require the following as part of the monitoring program:

1) Continuous monitoring for pressure in the aquifer located directly above the injection zone;

2) Other site specific data to include information on the position of the waste front within the injection zone or water quality;

3) Monitoring of ground water quality of the aquifer located directly above the injection zone;

4) Monitoring of ground water quality in the lowest underground source of drinking water; and,

5) Any additional monitoring to determine if there is fluid movement into underground sources of drinking water.[37]

Class II well operators are required to monitor injected fluids to determine how it moves and changes while in the injection zone, and the frequency of which is determined in each permit based upon site specific criteria.[38] Operators are also required to monitor and record injection pressure, flow rate, and cumulative volume, the frequency of which can vary from daily to monthly, dependent upon the type of well operations.[39] Well operators must demonstrate mechanical integrity at least every five years.[40]

Reporting

Reporting requirements also differ between Class I and Class II wells. Operators of Class I wells must submit quarterly reports with the following information: various characteristics of the injection fluid, monthly average and minimum and maximum values for injection pressure, flow rate/volume, well pressure monitoring well results, and the results of injection

[34] 40 CFR Part 146.8

[35] 40 CFR Parts 146.13 and 146.23.

[36] 40 CFR Part 146.13(d)(1).

[37] 40 CFR Part 146.13(d)(2).

[38] 40 CFR Part 146.23(b)(1).

[39] 40 CFR Part 144.28(g)(2); 40 CFR Part 146.23(b)(2).

[40] 40 CFR Part 144.28(g)(2)(iv); 40 CFR Part 146.23(b)(3).

well tests.[41] Class II well operators are required to submit annual reports providing a summary of results from any required monitoring activities.[42]

Financial Assurance

For now, APPA is not aware of any additional financial assurance programs or systems envisioned for CCS. However, the existing law does require that financial responsibility is met. APPA has caution about embracing CCS technology and long-term storage or geosequestration for new power plants until this financial responsibility issue is better understood. To APPA's knowledge, there has been nothing like this level of financial assurance required in the electric power sector for conventional pollution issues and liability concerns.

Currently, Class I operators must demonstrate and maintain financial responsibility for each well to ensure the operator is financially able to eventually close and abandon the well in accordance with an approved well abandonment plan.[43] Class I operators have several options from which to choose in order to demonstrate financial responsibility.

1) Establish a trust fund in an amount equal to the estimated cost of plugging and abandonment;
2) Obtain a surety bond to guarantee payment into a standby trust fund;
3) Obtain a surety bond to guarantee well plugging and abandonment;
4) Obtain a letter of irrevocable plugging and abandonment letter of credit;
5) Plugging and abandonment insurance;
6) Meet financial criteria and obtain a corporate guarantee for plugging and abandonment; or,
7) Demonstrate financial responsibility using a combination of options 1, 2, 4, 5.[44]

Closure

Well operators must submit plans for plugging and abandonment as part of the permit approval process. [45] UIC program regulation requires Class I, II, III, and V wells to be plugged with cement sufficiently to prevent migration or leakage of the injection fluid. Class I permit holders must also monitor groundwater until they can demonstrate that the pressure in the injection zone decays to the point where there is no potential to influence underground drinking water sources.[46] Class V operators are also required to dispose of any waste, sludge, fluids, etc., that are found near the wells.[47] Well operators are required to submit a report

[41] 40 CFR Part 144.28(h)(1).

[42] 40 CFR Part 144.28(h)(2).

[43] 40 CFR Part 144.28(d).

[44] 40 CFR Part 144.63.

[45] 40 CFR Part 144.28(c).

[46] 40 CFR Part 14.28(g)(1)(iii).

[47] 40 CFR Part 146.10.

certified as accurate to the Director stating that well abandonment was conducted and completed in accordance with the abandonment plan.

What are the Challenges for Permitting CCS Under the UIC Program for Electric Utilities Evaluating CCS Options?

With the international, federal, and state interest in CCS, academic, public interest groups, and the federal government researchers are promoting the availability of sequestration sites. The Department of Energy estimates that North America has the capacity to store all of its annual power plant emissions underground. The APPA is very skeptical of DOE's optimistic view because APPA does not believe that hydrological concerns and proximity to transmission lines, water issues and other infrastructure needs have been considered. Yet, new electric utilities are being asked to respond and to consider CCS as part of new plant design now.

The APPA is concerned that these studies do not fully consider the technical, regulatory, and practical limitations of commercial-scale CCS. The current UIC regulatory program illustrates some of the major limitations utilities and policy officials must consider:

Cost and Space Requirements for CCS at the Power Plant

The DOE estimates that a 300 MW power plan will require 60 acres of land to build and to operate the carbon capture technology.[48] Constructing the pipeline terminus for $C0_2$ compression and transport via pipeline will require an additional 20 acres of land. DOE further estimates that carbon capture will consume 0.5 millions of gallons of water per day and over 15 megawatts of power or approximately 0.8 MGD per day for a 500 MW power plant. If utilities do not have readily available land and water, and can afford the costs of excess generating capacity, they will face limitations on their ability to construct CCS.[49]

Uncertainty Concerning Regulatory Requirements

Since EPA is formulating guidance or regulation on CCS and the UIC program, there is substantial uncertainty as to the ultimate siting, construction, and other permit requirements. If EPA embarks on a rulemaking, a final rule may not be promulgated until 2012. Once EPA completes its policies, states may enact their own more stringent provisions. This uncertainty complicates commercial scale planning for new power plants with coal on the drawing board today.

Operators of Class I, II, or III wells are expected to take corrective measures when there is noncompliance or malfunction of the injection system, which may include temporary shut down and capping of the well. The operators are required to notify the UIC regulatory manager within 24 hours of when the operator becomes aware of the problem. Operators are also expected to include in their noncompliance report its cause, period of time it occurred, actions taken (or are taking) to correct the issue, and plans to prevent recurrence.[50] Other specific requirements may be established as part of the operators UIC permit. However, the difficulty for well operators involved in CCS operations is finding an alternative means of disposing CO_2 emissions if injection operations must temporarily cease. Operators may have to negotiate this issue as part of the well permitting process.

[48] *NETL report*, at 2-44.

[49] *NETL report*, at 2-44.

[50] 40 CFR Part 144.28(b)

Limitations on Class I Well Siting

If EPA and states draw upon the criteria for Class I wells for CCS wells, there are regulatory, technical, and transportation limitations for CCS that utilities must consider. On a technical basis, some areas of the U.S. would be unsuitable due to the relatively increased risk of earthquakes, for example. Many of the coal regions of the United States also correspond to areas that are relatively geologically active (e.g., areas of Wyoming[51]). Injection near population centers along the West Coast also might be ruled out due to seismic concerns. Until the siting criteria are defined, utilities may not be certain whether they can inject locally or be required to pipe CO_2 hundreds of miles to areas with Class I wells such as the Gulf Coast.

Sheer Size of CCS to Have Meaningful Impact on U.S. GHG Emissions

Another limitation is that the EPA and states may not have the human and financial resources to administer an expansion of the UIC program for CCS. Comparing the relative size of CO_2 emissions and current underground injection gives some answer to this question. Power plants accounted for 2.4 billion metric tons of CO_2 emissions in 2006[52] or approximately 86 percent of point source CO_2 emissions in the U.S.[53]

By way of comparison, EPA reported that 21.8 million tons were injected into hazardous waste wells in 2005,[54] less than one percent of the amount of carbon dioxide released. Approximately 43 million metric tons of carbon dioxide is injected into wells today for enhanced oil and gas recovery.[55]

If perhaps 10-20 percent of carbon dioxide emissions were captured, the UIC programs would need to permit wells injecting masses 10 - 20 times the total mass currently injected for oil recovery or for all hazardous waste disposals. This expansion would pose a substantial challenge to the existing state permitting systems. APPA remains skeptical that more than a slip stream of CO_2 can be separated and injected and remains doubtful that a new coal power plant (regardless of type) could separate and inject more than 50 percent of the CO_2 from the plant.

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[51] http://ga.water.usgs.gov/edu/gwdepletion.html

[52] Electric Power Research Institute, *Electricity Technologies in a Carbon-Constrained World.*

[53] *Carbon Sequestration Atlas*, at 11.

[54] U.S. EPA Office of Solid Waste and Emergency Response, *National Biennial RCRA Hazardous Waste Report: Based on 2005 Data*, Dec. 2006, at 2-5, Exhibit 2-5.

[55] Source: Advanced Resourced International, 2007.

Figure 5: Comparison of CCS Volumes to Current UIC Volumes

Injected Material	Mass of Material (mil. Metric tons/year)
CO_2 emissions from power plants	2,400[56]
CO_2 in Class II wells for oil recovery	43[57]
Class I hazardous waste	22[58]
Regional Carbon Sequestration Partnerships, total	2

Space Requirements for the Injection Well

DOE has estimated that injecting 0.9 million metric tons of CO_2 will require a land area of over 2,750 acres. This carbon mass is only 40 percent of one year's generation from a 300 MW coal power plant with a 90 percent efficient CCS. Using DOE's estimate, to hold 30 years of CO_2 captured from a 300 MW boiler, the surface area requirement is over 200,000 acres, or 312.5 square miles.[59] This land choice must also consider load, transmission lines, coal or rail access, surface water (used to produce electricity) and conventional air pollution issues such as SO_2 and NOX. The injection well, observational well and Area of Review (AoR) space issues will dictate where the future power plants can be built.

The U.S. DOE's estimate may significantly underestimate the land area needed. As a gas, carbon dioxide is different then diluted wastewaters currently injected in Class I wells. It is more buoyant than the underwater fluids and will rise to the top of the injection layer. If the injection layer has dips and rises, CO_2 will flow to fill in each rise first. In other words, unlike current injected fluids, it will migrate via diffusion on its own away from the injection well. Like natural gas, it will concentrate in traps miles away from the injection zone. In other words, applicants could have areas of review much greater than 2.5 miles currently thought protective for liquid injection. A study in the saline formations of Texas where there are many Class I wells suggests that a formation large enough to store 30 years of CO_2 from a single power plant could have traps over a 13 mile by 13 mile area.[60]

A further complication is the difference in property law traditions across the United States. In several Homestead laws, Congress gave away land to settlers who stayed upon and improved the land. However, the federal government retained the subsurface rights to the land, creating "split-estate" properties where the surface owner does not have title to the subsurface. Over 20 million acres of land in western U.S. states have split estates between private entities and the federal government.[61] In other states, the mineral rights have been sold to private parties creating split estates between parties. In the eastern U.S., property titles typically include surface and subsurface rights. Depending on the state, utilities may

[56] Electric Power Research Institute, *Electricity Technologies in a Carbon-Constrained World.*

[57] Source: Advanced Resourced International, 2007,

[58] U.S. EPA Office of Solid Waste and Emergency Response, *National Biennial RCRA Hazardous Waste Report: Based on 2005 Data*, Dec. 2006, at 2-5, Exhibit 2-5.

[59] *NETL report*, at 2-71

[60] J.P. Nicot *et al.*, *Area of Review: How large is large enough for carbon storage?*, Bureau of Economic Geology, Jackson School of Geosciences, The University of Texas at Austin, 2006.

[61] NETL report, at 4-83.

face the limitation that it is impractical, impossible, or extremely costly to acquire title to hundreds of thousands of acres of land.

Unique Potential Hazards of Carbon Dioxide Injection

While deepwell injection of liquids has occurred safely for over 20 years, there is less experience with injecting gasses like CO_2. While most CO_2 injections for enhanced oil recovery have occurred safely, problems that have occurred illustrate the unique hazards that utilities and regulators must consider. A few of these potential hazards include the following.

Blowout

Well blowouts occur when gas escapes through old or unknown wells. In January 2001, a natural gas leak from a cracked gas well casing leading to salt caverns and used as a natural gas storage facility resulted in an initial gas explosion below two stores in downtown Hutchinson, KS. The initial gas explosion was followed by an eruption of natural gas and water geysers two miles east of the initial explosion later that day and for several days thereafter. Two people residing in a trailer home were killed as a result of one of the explosions. The gas leak originated from a cracked well casing at a depth close to 600 feet and proceeded to migrate horizontally, traveling along abandoned brine wells and ultimately reaching the surface some distance away from the initial explosion.[62]

In another case involving CO_2, a blowout occurred during drilling at a production well in March 1982 causing the free flow of CO_2 at the well head and leakage from ground fractures directly above the site. The high rate of CO_2 from the well caused containment not to occur until the following month.[63]

A report jointly funded by U.S. EPA and U.S. DOE looked at injection well accidents in both the U.S. and abroad and issued recommendations for protecting against future accidents.[64] The report issued a number of recommendations including: determining the potential for CO_2 migration along unsealed fault and fracture zones; the potential for magmatic or seismic activity to cause damage to sealing caps resulting in CO_2 releases; the potential for wells to transport CO_2 to the surface; and implementation of public education and CO_2 monitoring programs to minimize impact to human health and the environment from releases.[65]

The risk of blowout is hard to quantify since there is little information on the number of abandoned wells in the United States. It is difficult to estimate the number of these wells since some do not have observable caps or metal casings that can be detected through sensors. Texas estimates that there are approximately 11,000 orphan abandoned wells that it is gradually closing through a state program.[66] Operators of CCS injection wells will have to find, close, and cap abandoned wells within the Area of Review.

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[62] Lewicki *et al.*, at 41-2.

[63] Lewicki *et al.*, at 39-40.

[64] Jennifer L. Lewicki *et al.*, *Natural and Industrial Analogues for Release of CO_2 from Storage Reservoirs: Identification of Features, Events, and Processes and Lessons Learned*, Earnest Orlando Lawrence Berkeley National Laboratory, Feb. 2006.

[65] Lewicki *et al.*, at 48-9.

[66] Source Texas Railroad Commission at: http://www.rrc.state.tx.us/news-releases/2006/100606.html..

The DOE has a method of finding abandoned wells under its SEQURE program, however this program is not set up for national application. The SEQURE program uses low flying airplanes to detect abandoned wells and, as discussed above, aerial methods may not detect wells which do not have metal cases or other markers.

Economic Damage

The saline formations in Texas produce some oil and gas in formations nearby or overlaying the potential injection formations. In addition to well blowout, less apparent seeps from the injection zone into oil and gas producing layers can dilute the value of these deposits and ultimately return the CO_2 to the atmosphere.[67]

Corrosion

As CO_2 rises to the top of the injection layer, it may contact closed wells or the cement casings of older wells. If the CO2 reacts with water to form acidic compounds, these acids could start to erode the concrete. As more is eroded, the process accelerates, creating a reinforcing-negative cycle that could allow the CO_2 to rise up the abandoned well to drinking water layers. While this problem can be prevented through different well closure approaches, the potential problem will increase the cost of an applicant's Area of Review study and demonstration.[68]

Permitting Costs

In 2001, EPA estimated the costs of the siting requirements - the geologic study, the Area of Review study, and the no migration petition - as at least $2 million for a Class I hazardous waste well.[69] EPA based its estimate on applicant experience, including an Area of Review of 2.5 miles. If, as discussed above, the zone of influence could stretch to a radius of 13 miles, the Area of Review would be 26 times larger than for a typical Class I well. The siting studies and corrective measures for closing abandoned wells could approach $20 to $50 million. Operators (presumably electric utilities) would still need to pay for the well construction costs (estimated to be well over $1 million), permitting fees, operating, and the other costs.

Regulatory Capacity

In all, a Class I permit application can fill a bookcase with the required plans, analyses, and reports. States may spend over a year reviewing a renewal permit and several years reviewing a new Class I well permit.[70] Because of the regulatory burdens, APPA staff speculates that states will require considerable permit fees to pay for these new state employees as well as analyses of new and renewed[71] permit applications. Class II permits can be approved more rapidly. However, and as the maps show, as the UIC program has matured, Class I and II wells primarily now only occur where there is ample experience and knowledge of local and regional geography.

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[67] Nicot, et al.

[68] Nicot, et al.

[69] EPA, 2001, at 20.

[70] Source: Texas Commission on Environmental Quality (TCEQ) at http://www.tceq.state.tx.us/assets/public/comm_exec/pubs/sfr/057_06.pdf.

[71] Class I permits may remain in effect for up to ten years as determined by the Program Director. See, 40 CFR 144.28.

Even moderate adoption of CCS by new electric utilities would be the biggest expansion of underground injection in U.S. history. From the volumes above, the U.S. must undertake a dramatic expansion in its technical infrastructure to support safe CCS. In the private sector, engineers and geologists must identify, map, and investigate many more UI sites. In the near term there may be a shortage of experienced investigators. For the public sector, the skill gap is even more critical. Regulatory agencies must have sufficient in-house experience to review all of the technical information provided and to evaluate permit applications against the regulatory standards.

The size of the current regulatory skill shortage is illustrated by the following:

- ***Less than half of regulatory agencies across the states have experience reviewing Class I or Class II permits.*** As the charts show, only about 20 states have experience permitting deep, high-volume injection wells. For CCS to occur in geologic formations around the U.S., many states must hire and train permitting staff or rely on EPA regional offices.

- ***Experience is concentrated in a few regions of the country.*** Current experience is not distributed throughout the country, but concentrated in Texas, Louisiana, Florida, and a few other states. Unless states accept deep well injection in their states, CCS may require special CCS pipelines or via surface shipping carbon dioxide gas hundreds or thousands of miles from a power plant to an injection well. Pipeline shipment and booster compressors along the CCS pipeline increase the cost and perhaps the perception of the hazards of CCS.

- ***EPA regions must also boost their technical capacity.*** It is not only states that will be deluged with CCS permit applications. EPA regions approve UIC permits in some of the nation's largest states and in states with large coal-fired power plants. EPA regions must craft their own approaches and technical requirements for CCS Class V permit applications.

- ***Even in states with experience, states would need a significant boost in resources to permit a larger number of CCS wells.*** In 2006, Texas had ten new and eight Class I hazardous waste permit renewals under review. The average processing time was over one year for these permits. If CCS increases by a factor of ten the effective number of Class I wells in Texas, the regulatory system must either grow rapidly or the time needed to gain approval will soar.

Another consideration is the increased regulatory burden faced by electrical utilities when partnering with enhanced oil recovery (EOR) operations. Electrical utilities partnering with Class II well operators for EOR presumably would be subject to current Class I regulatory provisions, and ultimately any new regulatory requirements or framework established by U.S. EPA specifically to address CCS injection activities.

Conclusion

Although the concept of CCS sounds promising, regulatory agencies' paramount responsibility will be to ensure current and future protection of the nation's drinking water supplies. For CCS to have a meaningful impact on U.S. power plant emissions, the mass of CO_2 to be injected underground will dwarf current amounts by 10 to 20 times. While the nation has the ingenuity to tackle this challenge, it will require investing in technical skills, data, research, carbon separation technology at the power plant. This is a step that, generally speaking, EOR sites do not require. [3]

The purpose of this white paper is to introduce environmental and legal issues that may require additional research before large-scale CCS can be implemented safely and effectively in the public power utility sector.

Human Health and the Environment

Despite the successes of EOR or tertiary recovery of oil and gas using CO_2 injection, leakage from embedded CO_2 deposits could result in the endangerment of ecological and human health given the scale of the utility sector's emissions. A better understanding of these impacts is necessary in order to take precautionary steps to mitigate them or avoid them entirely.

- Prolonged exposure to elevated concentrations of CO_2 can be harmful to human respiratory and central nervous systems.
- The release of large volumes of high concentrations of CO_2 can result in the suffocation of humans, animals, or plants above ground. For instance, natural CO_2 long-term seepage destroyed 40 hectares of trees on Mammoth Mountain in the Eastern Sierra Nevada mountain range in California.[4]
- Leakage from injected CO_2 could migrate into Underground Sources of Drinking Water (USDWs). Migrating CO_2 deposits may alter the pH of subsurface groundwater or displace potable water resources by forcing saline waters to merge with fresh water formations.
- According to the U.S. EPA, 44 percent of all U.S. drinking water is from groundwater, a considerable increase from only 5 years ago when most U.S. drinking water was from surface water sources.
- Current research suggests that injecting carbon into saline aquifers poses a threat to groundwater because of brine contamination.[5] Since it is not clear how large-scale CCS activities would address this concern, additional research is required considering the growing reliance on groundwater for use as drinking water.
- CCS could potentially cause displacement of native fluids and chemical constituents, movement of possible hazardous substances, or potential leaching of naturally occurring metals and minerals mixed in the CO_2 injection.
- If the CCS process is responsible for discharge of a pollutant or hazardous substance (such as arsenic) into or upon navigable waters, this may incur administrative and/or civil penalties under the Clean Water Act (CWA).[6]

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[3] Complete explanation of separation technology issues available. See L. D. (Doug) Carter, Carbon Capture and Storage From Coal-based Power Plants: A White Paper on Technology, American Public Power Association, 22 May 2007.

[4] C.D. Farrar, M.L. Sorrey, W.C. Evans, J.F. Howle, B.D. Kerr, B.M. Kennedy, C.-Y. King, and J.R. Southron, "Forest-killing Diffuse CO_2 Emission at Mammoth Mountain as a Sign of Magmatic Unrest," *Nature* 376 (1995): 675-678.

[5] Brian McPherson and Peter Lichter, *CO_2 Sequestration in Deep Aquifers*, http://www.netl.doe.gov/publications/proceedings/01/carbon_seq/7a2.pdf.

[6] CWA § 101

Property Rights

The legal mechanism for securing property rights for large carbon sequestration sites may currently be ineffective in many states, leading to unforeseen costs and delays. It also may lead to tensions between large-scale CCS projects and individual property rights.

- Since sub-surface land can be privately owned in the United States, CO_2 injection into geologic formations may require permission from all private owners of intersected sub-surface property. A proposed deposit for a FutureGen zero-emissions plant site may require property rights from 69 individual property owners.[7]
- Compulsory unitization laws for oil and gas production operations, currently used in some states to compel private property owners to permit large oil and gas sub-surface projects when a high percentage of affected property owners do accept, may be used extensively for enhanced oil recovery-related CCS.
- For non-oil and gas production projects, the use of eminent domain laws, currently used for sub-surface natural gas storage fields, may be necessary for CCS projects. Widespread use of local and state eminent domain laws for CCS may be politically difficult, given the public backlash against eminent domain driven by the Supreme Court case *Kelo v. New London.*[8]
- There is currently a significant level of uncertainty in predicting migration and movement of large CO_2 deposits in large geologic formations. Without further research, the scale of property right acquisition for CCS projects will remain high, as industry participants will seek to minimize liability from property trespass claims related to sub-surface trespass, geological surveying, and deposit monitoring.
- This scientific uncertainty may interfere with the availability of liability insurance for CCS project participants. If insurance companies cannot accurately calculate the risk of CO_2 damages, or future potential environmental liability, they may decline to offer coverage to public power utilities. Some public power utilities may not have the insurance coverage thought to be sufficient to handle the perceived risks for geologic sequestration or storage of CO_2.
- The utilization of regional land use controls to ban large-scale CCS projects near valuable natural resources may be an obstacle to implementing projects in viable locations.

General Regulatory Framework

The current federal and state regulatory framework may be insufficient for ensuring a fair resolution in the event of leakage damage to human health or private property.

- Currently, CO_2 has not yet been classified as a pollutant or a hazardous substance. If embedded CO_2 is not classified as such, then federal environmental statutes may lose protection from CO_2 leakage damage, since these laws were created to assess and assign responsibility for damage from hazardous substances. However, CO_2 could ultimately be classified as a pollutant, especially if large-scale implementation of CCS leads to negative impacts on environmental media. This classification would

[7] Elizabeth Wilson and Mark de Figueiredo. "The Impact of Liability on the Adoption and Diffusion of Carbon Capture and Sequestration Technologies," page 6.
[8] 545 U.S. 469 (2005).

have a significant legal impact and would likely increase the costs associated with CCS activities.

- There is uncertainty in the governance of the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA) over private property damage cases that are caused by sequestered CO_2. No carbon injection subsurface trespass legal precedents exist, and there is scientific uncertainty of embedded CO_2 impacts.
- If the CCS process causes a release or substantial threat of a release of any pollutant that may present an imminent and substantial danger to the public health or welfare, liability will likely attach under CERCLA.[9]
- If area-wide contamination is the result of CCS activities, potential parties could be held liable under CERCLA. To the extent that specific provisions of the CWA and the Safe Drinking Water Act (SDWA) are incorporated into the applicable or relevant and appropriate requirements (ARARs), those standards could then govern the remedial activities of a CERCLA cleanup.
- In the case that CCS results in collateral damage to natural resources, responsible parties could be made liable under the Natural Resources Damage Assessment (NRDA).
- The existence of citizen suit provisions, especially with respect to water laws in the Western U.S., introduces another level of uncertainty because any regulatory balance can be altered by a citizen bringing suit because of a lack of prosecutorial diligence, whether actual or perceived.
- In nuisance tort cases or other grievances related to CO_2 leakage, the potentially responsible parties under CERCLA are unclear. Federal and state government regulators, carbon injection operators, and public power generators of CO_2 may all be candidates for some portion of liability under the "joint and several liability" provision in the CERCLA statute's "cradle to grave" liability scheme.
- There may be legal difficulty in assigning responsibility for seismic disruption damages caused by carbon injection due to scientific uncertainty and lack of a legal precedent.
- In the case of natural seismic action leading to future CO_2 leakages, assigning liability based on fault may be impossible and lead to difficulty in handling the resultant damages.

Long-Term Stewardship and Liability

Assignment of liability associated with leakage and migration of CO_2 deposits and resulting public health or environmental impact is further complicated by the extended time frame of carbon storage, which may exceed the lifespan of industry participants. For example, determining <u>which</u> party is responsible for the CO_2 monitoring at a power plant after the plant is decommissioned or retired is difficult.

- The existing legal framework for EOR carbon sequestration has insufficient long-term storage and monitoring controls for large-scale CCS projects.
- The continuous existence of a viable entity is questionable under the current legal framework. It is still an open question whether long-term liability should rest with a public or private entity. To ensure the future economic burden associated with the

[9] CERCLA § 104

CCS site will not rest on the public as a whole, issues of long-term stewardship, land use controls, and data tracking will need to be addressed.

- Assignment of liability in CO_2 releases is especially difficult if the companies that managed the injection and monitoring no longer exist or if they utilize subsidiaries to limit liability.
- Additional research is required to improve scientific knowledge of carbon storage, which would help to inform the liability debate.
- Plugged CCS injection sites will require effective long-term stewardship performed by a government or private entity. A detailed framework must be firmly established in the U.S. Environmental Protection Agency's (EPA) Underground Injection Control Program, which provides governance for CO_2 injection under the SDWA.[10]
- Although geologic sequestration currently meets the statutory definition of "underground injection" in section 1421(d)(1) of the SDWA, EPA is currently evaluating Department of Energy (DOE) pilot projects to determine if changes to the regulations are required for long-term CCS.
- Since EPA currently has the statutory mandate to protect underground sources of drinking water and aquifers, the unknown results of these DOE pilot projects leaves legal uncertainty with respect to the future of CCS activities.

Further Research

This white paper is intended as an overview of potential environmental and legal issues that could arise in a large-scale CCS operation. It is meant to promote further research and discussion of these areas before large-scale CCS implementation can provide one of the many technological solutions to constraining carbon from existing or future power plants. A pressing need for reducing greenhouse gas emissions and halting their effect on climate change is driving the current political impetus to institute commercial-level CCS on a short time frame. However, for commercial CCS to effectively reduce emissions and mitigate the effects of climate change, a comprehensive plan and effective regulatory framework that respect potential obstacles and adverse impacts are essential.

Technical and economic barriers to implementing commercial-level CCS are substantial, but they are also currently under significant scrutiny. The legal and environmental challenges of CCS should be analyzed and addressed with similar vigor in order to promote effective and sustainable practices in the United States. Research on these aspects will inform cost-benefit analyses of CCS in relation to other methods being developed to mitigate climate change, allowing for optimal distribution of public and private resources.

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[10] Testimony of Acting Assistant Administrator William Wehrum and Assistant Administrator Ben Grumbles, U.S. Environmental Protection Agency. *Subcommittee on Energy and Air Quality, United States House of Representatives*, 6 March 2007.

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GETF is a 501(c) (3) not-for-profit foundation that works with government, industry, academia, and non-governmental organizations to advance sustainable solutions and practices that promote environmental stewardship.

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Retrofitting Carbon Capture Systems on Existing Coal-fired Power Plants
A White Paper for the American Public Power Association (APPA)

L.D. Carter

December 2007

Summary: It will be necessary to reduce CO_2 emissions from existing coal-fired power plants for the U.S. to reach the goals stated by some legislators for managing global climate change. The major technology choices for existing plants include post-combustion capture systems using chemical sorbents to isolate and concentrate CO_2, and reconfiguring the unit to use pure oxygen rather than air as the combustion oxidant (yielding flue gas with a much higher concentration of CO_2). Both existing technology approaches are costly, and both involve large parasitic power needs that can reduce the output of the existing unit by one-third. The changes introduced by retrofitting carbon capture and storage (CCS) on an existing power plant will raise variable costs, and could thereby lower the unit in the utility's dispatch order.

Capture and storage concepts have been implemented on a small scale, but not on the scale necessary for large coal-fired power plants. Furthermore, most research on CCS is focused on new power plants and not issues that may be more relevant to existing power plants. In addition to overcoming technical issues, CCS retrofits will face as yet undefined regulatory challenges, as well as liability issues related to the underground migration of stored CO_2 over a timescale that exceeds the scope of traditional risk mitigation instruments, like insurance.

These challenges are daunting. Research and policy development are both proceeding, but whether current efforts will be sufficient to result in a solution set that enables the nation to continue to enjoy the benefits of low-cost electric power remains to be seen.

Introduction

Existing coal-fired power plants in the U.S. emitted 1.96 billion metric tons of CO_2 in 2005, or about 27% of total U.S. emissions of greenhouse gases (GHGs).[1] These power plants generate about one-half of the electricity in the U.S., and are in large part responsible for the U.S. enjoying power costs that are among the lowest in the world.[2] Congress has not passed legislation to reduce GHG emissions, but many bills have been introduced and others are under development, with some seeking reductions in U.S. emissions as high as 30% in 2030 and 80% in 2050.[3] The Chairman of the House Energy and Commerce Committee has identified a reduction goal for that committee's legislation of "between 60 percent and 80 percent by 2050."[4] Such large emission reduction goals will not be met without significantly reducing emissions from existing coal-fired power plants.

To date, most discussion of GHG emission mitigation related to coal-based power production has focused on new coal-based power production, and detailed engineering studies have evaluated the cost and performance of various options for those new units.[5] With currently available technologies, CO_2 capture and storage options (in saline formations) from these new units cost $30 – 70 per ton of CO_2 avoided.[6] [7] The reader is referred to an earlier APPA White Paper for a general overview of carbon capture and storage (CCS) from coal-based power plants.[8] This paper addresses those aspects of CCS that are of particular interest to retrofitting this technology on existing coal-fired power plants.

With respect to retrofitting existing coal units, a 2005 IPCC report concluded: "*Retrofitting existing plants with CO_2 capture is expected to lead to higher costs and significantly reduced overall efficiencies than for newly built power plants with capture. The cost disadvantages of retrofitting may be reduced in the case of some relatively new and highly efficient existing plants or where a plant is substantially upgraded or rebuilt.*" [9]

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[1] Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1900 – 2005, U.S. EPA, EPA 430-R-07-002, April 15, 2007. Note that the percentage includes non- CO_2 greenhouse gases, and excludes sinks.

[2] Electricity Prices for Industry, DOE/EIA, June 2007, http://www.eia.doe.gov/emeu/international/elecprii.html .

[3] Climate Change: GHG Reduction Bills in the 110th Congress, Congressional Research Service, Rpt. #RL33846, January 31, 2007.

[4] Memorandum from John Dingell, Chairman of Committee on Energy and Commerce, and Rick Boucher, Chairman of Subcommittee on Energy and Air Quality, to Members, Committee on Energy and Commerce, October 3, 2007.

[5] See, for example, Cost and Performance Baseline for Fossil Energy Plants, U.S. DOE National Energy Technology Laboratory, DOE/NETL-2007/1281, May 2007.

[6] *Ibid.* It should be noted, however, that most publicly available reports on CO_2 capture and storage are based on markets that existing before 2005, and that since that time, power plant capital costs have escalated dramatically. The NETL report states (p.42) that it incorporated escalation through the 3rd Quarter of 2006, but the basic power system costs cited still appear below costs reported by utilities in the news media.

[7] Carbon Dioxide Capture and Storage, UNEP/IPCC, 2005, avoided costs projected at 30-70 $/t CO_2 for new pulverized coal units and 14-53 $/t CO_2 for new IGCC units, p.347.

[8] Carbon Capture and Storage From Coal-based Power Plants: A White Paper on Technology for the American Public Power Association (APPA), L.D. Carter, May 22, 2007 (available from APPA at http://www.appanet.org/files/PDFs/Attachment%20%233.pdf).

[9] *Op.Cit.*, Carbon Dioxide Capture and Storage, p.10.

Technology Choices

The vast majority of existing coal-fired power plants are pulverized coal units. Pulverized coal units have two choices for CCS retrofit: post-combustion capture of CO_2 using chemical sorbents, and replacing the existing air-combustion system with an oxygen-fired system, thereby creating a flue gas which is mostly CO_2.[10]

Post-combustion CO_2 capture

Figure 1 depicts a post-combustion CO_2 capture system. In this system, an acid gas sorbent vessel is placed downstream of conventional pollution capture systems. CO_2 is absorbed into an appropriate chemical, such as an amine, which is heated in a separate vessel to release a high concentration stream of CO_2 and the regenerated sorbent. The concentrated CO_2 stream is then pressurized to about 2000 psia, for transport (as a supercritical fluid) via pipeline to an injection field. There it is injected into a stable formation as deep as one mile underground. The process requires large amounts of energy, both to strip the CO_2 from the sorbent and to compress the concentrated CO_2. In a study of capture technology at greenfield, or new, power plants, NETL[11] concluded that whether the plant was subcritical or supercritical in design, the CCS system resulted in about a 12% absolute drop in efficiency (e.g., from 33% to 21%).[12] Figure 2 shows the components responsible for the additional power needs in the CCS-equipped system, based on data in the NETL report for a subcritical power plant. As can be seen from the figure, about one-half the power needs related to CO_2 compression, about one-fourth was attributable to the CO_2 amine system, and most of the rest derived from additional fans and pumps needed for the enlarged generation system (which burns more coal for the same power output) and the greatly enhanced cooling system. The CO_2 capture system (alone) requires about twice as much cooling water as the original power plant.

An additional complexity of the CCS-equipped system is an SO_2 polishing unit. For a high sulfur (IL #6) coal system, even a 98% efficient wet FGD system exhausts flue gas with about 40 ppm SO_2. To suppress formation of heat stable salts in the sorbent, this must be lowered to about 10 ppm. The NETL design accomplishes this at a new unit by using a serial combination of a traditional wet limestone FGD and a sodium hydroxide polishing scrubber.

The various pieces of hardware required for CO_2 capture and compression require space. NETL reports that about one acre of land is needed for each 100 MW of generating capacity.[13] A separate NETL report suggests that land requirements for capture and compression equipment at a 500 MW unit would be 60 acres, or 12 times the first estimate.[14] In either case, this space requirement can be a major obstacle to retrofitting CO_2 capture systems on existing units which are already space-limited due to previous retrofits for SO_2, NOx, and mercury control systems.

[10] An innovative multipollutant ammonia-based capture technology is currently being investigated by U.S. DOE, in collaboration with Powerspan Corporation. The lack of publicly available data on a commercial version of this technology preclude its inclusion in this analysis. Additional information is available at: http://www.netl.doe.gov/publications/factsheets/rd/R&D043.pdf .

[11] NETL is the National Energy Technology Laboratory, which is owned and operated by the U.S. Department of Energy. See: http://www.netl.doe.gov/ .

[12] *Op.Cit.*, Cost and Performance Baseline for Fossil Energy Plants, Exhibit ES-2.

[13] Carbon Dioxide Capture from Existing Coal-Fired Power Plants, DOE/NETL-401/120106, p.xviii, December 2006.

[14] Carbon Sequestration Program Environmental Reference Document, DOE/NETL DE-AT26-04NT42070, August 2007, p.2-42.

Regarding technology readiness, the 2007 NETL report states: "The post-combustion CO_2 removal technology for the PC and NGCC cases is immature technology. This technology remains unproven at commercial scale in power generation applications."[15]

Oxy-combustion approaches

If a pulverized coal power plant is fired with nearly pure oxygen, instead of with air, the nitrogen in the traditional combustion air is eliminated from the flue gas, and the flue gas is composed primarily of CO_2, water vapor, excess oxygen and trace gases like SO2, NOx, and HCl, although air infiltration can reintroduce nitrogen and more oxygen. After removal of water vapor, the flue gas is approximately 80-98% CO_2.[16] As a result, the sorption/desorption equipment needed in the "Post-combustion" example above is unnecessary, although some purification may be needed prior to CO_2 injection and storage. For purposes of this paper, this oxygen-based approach to CO_2 capture will be termed "oxy-combustion", even though it is actually another form of "post-combustion" CO_2 capture.

In the oxy-combustion system, some of the CO_2 from the flue gas (about twice the volume of the oxygen supplied) must be recycled to reduce combustion gas temperatures from 3500 °C to a boiler tolerant 1900 °C. Oxy-combustion raises the possibility of reduced cost for downstream cleanup of traditional pollutants, either by storing them with the CO_2 or by reducing the volume of the flue gas stream dramatically through elimination of nitrogen oxide and use of CO_2 recycle.[17] Additionally, the potentially higher combustion temperatures and the improved heat transfer properties of oxy-combustion gases mean that it may be possible to achieve higher thermal efficiencies than possible with other approaches to CO_2 capture.

The major drawbacks to this approach for CO_2 capture are large parasitic power requirements, primarily for oxygen production and CO_2 compression, and the cost of the oxygen production facility. Ongoing research into improved techniques for oxygen production may mitigate these drawbacks to some degree. With current technology, cost and parasitic power needs for oxy-combustion are about the same as for post-combustion CO_2 capture. The potential advantages for oxy-combustion CO_2 capture are speculative at this point. It may be easier to locate an oxygen plant than a CO_2 sorption tower at an existing plant, where access to flue gas is already encumbered by retrofit SO2 scrubbers and other hardware installed after the plant was initially constructed. And the parasitic power needs for an oxy-combustion plant are more electrical than steam, so integration with the existing unit may be simpler.

A cross-platform comparison

A recently published report by DOE/NETL compares a basic new pulverized coal unit both to one with similar power output, but with post-combustion CO_2 capture, and to a coal unit with oxy-combustion CO_2 capture. NETL examined both supercritical and ultra-supercritical designs.[18] Table 1 presents several outputs from the study for the supercritical designs.

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[15] *Op.Cit.*, Cost and Performance Baseline for Fossil Energy Plants, p.40. "PC" refers to pulverized coal power plants, the traditional technology for burning coal to produce electricity. "NGCC" stands for natural gas combined cycle power generation. In a NGCC, natural gas is burned in a combustion turbine (much like a jet engine) that drives a generator to make electricity. Hot exhaust gases from the combustion turbine are used to convert water to steam, which expands through a steam turbine to drive a second generator.
[16] *Op.Cit.*, Carbon Dioxide Capture and Storage, p. 122.
[17] *Ibid.*, p.123.
[18] Pulverized Coal Oxycombustion Power Plants, DOE/NETL-2007/1291, August 2007.

Note that both approaches to CO_2 capture, with current technology applied to a new power plant, nearly doubled the power plant's capital cost and the cost of electricity produced.

Table 1. Comparison of cost and performance of capture systems (new plant).

Parameter	Base	Post-comb'n	Oxy-comb'n
CO2 capture	No	90%	100%
Gross capacity, MWe	584	667	793
Net capacity, MWe	554	549	546
Net plant heat rate, Btu/kwh	8,649	12,538	12,074
Net plant efficiency (HHV), %	39.5	27.2	28.3
Total Plant Cost, $/kw	1563	2857	2930
Levelized cost of electricity, $/MWh	62.9	114.4	113.0
Cost of capture, $/ton CO_2 avoided	n.a.	63	52
SO2 emissions, #SO2/mmBtu	0.085	Negligible	0.003
NOx emissions, #NOx/mmBtu	0.07	0.07	0.07

It should be repeated that the above table relates to *new* power plants. Traditional pollution control technologies designed for new power plants usually have a higher cost per unit of power output when applied to existing units. These cost "retrofit factors" have not been established for carbon capture technology, but for traditional pollutants like SO_2 and NOx, they can be a 25-40% cost increase over the cost of a comparable system at a new facility. The other major distinction for existing units is that they cannot easily be expanded to accommodate the very large amount of parasitic power needed to run the capture systems. Note that for the new units in Table 1, gross generating capacity was increased 15-35% to provide that power. **At a retrofit unit with 33% energy conversion efficiency, a loss of 12% (absolute) efficiency means a loss of more than one-third of the output of the power plant.**

Replacement of this parasitic power, at today's escalated prices for new power plants, will introduce a major cost barrier to retrofitting existing units for CO_2 capture. It could also present limitations on how quickly regulations could be implemented. For example, recall that the 2005 Clean Air Interstate Rule (CAIR) was by necessity introduced in phases (the necessity being that skilled labor limitations precluded a one-step regulatory process).[19] Consider the comparative difficulty of retrofitting CO_2 capture systems on the existing 320 GW coal-fired power plant fleet. **The utility industry would need to install over 100 GW of additional new capacity for replacement power needs (above expected demand growth needs), and simultaneously install 320 GW of CO_2 capture and compression systems, versus roughly 100 GW of SO_2 scrubbers and NOx selective catalytic reduction systems under CAIR.**

A final issue specific to existing units is that a different level of CO_2 capture performance may be appropriate for those units. Most technical studies assume a high level, e.g., 90%, of CO_2 capture for new units[20]. Under either a cap and trade or carbon tax approach to managing greenhouse gas reductions, the best strategy is usually considered to be the one that achieves the desired global emissions reduction at the lowest cost. For existing pulverized coal-fired power plants, it is too early to determine what the most cost-effective level of control will be, but it might be much lower than 90%.

[19] Federal Register, 70FR25197, May 12, 2005.
[20] This level of performance has yet to be demonstrated as either technically or economically feasible.

Operational issues related to CCS

Most generating unit-level analyses of the cost impacts of environmental requirements focus on the levelized cost of electricity (COE) implications of meeting the rules. It is also important to examine dispatching costs (or variable costs) under alternative compliance scenarios, because if variable costs increase significantly, the unit may become too expensive to dispatch, making the capacity factor assumptions in the COE projections (and the COE results) invalid.[21] The costs for CCS retrofits are so large, and impacts on variable costs likewise large, that it is quite possible that a unit in which a large investment was made would not be used very much in an economically dispatched system. One only has to consider the significant amount of idle natural gas combined cycle (NGCC) units in the U.S. to recognize the reality that flawed assumptions with major economic ramifications are not just a theoretical possibility.

The large parasitic power requirements of CCS introduce additional analytical complexity regarding the use of systems equipped with CO_2 capture, particularly retrofit units. Dispatching costs for these units will be much greater due to the higher fuel consumption, and purchase of replacement power. Moreover, if replacement power were purchased from another source, then all of the cost of replacement electricity could be considered a variable cost. Figure 4 compares dispatching costs (or variable costs) for several hypothetical systems, based on cost and performance data reported by DOE/NETL.[22] The NETL costs were adjusted by assuming EIA AEO-2007 costs for natural gas and coal in 2020 (both the EIA reference price and "High Price" scenarios were used for natural gas). In addition, the NETL analysis was for a greenfield, or new power plant. A retrofit factor of 50% was applied to the capital and variable O&M costs for the new plant figures in the NETL report. Figure 4 presents dispatching costs for a range of carbon taxes (0-100 \$/metric ton CO_2), for coal and natural gas. Additionally, the costs in the figure reflect purchase of makeup power to replace the power required to run the CCS system, an issue further discussed below.

Note that the basic coal plant has a variable cost of about 20 \$/MWh and a natural gas plant is about twice that amount, without any CO_2 capture. At 90% capture, variable costs increase to about 60-65 \$/MWh for the coal system and for natural gas combined cycle systems equipped for capture, for a range of natural gas prices. The dashed lines in the figure represent an uncontrolled plant paying the relevant "tax", rather than capturing the CO_2, and a "hybrid" approach of controlling half the CO_2 and paying the tax for the remainder.

These calculations are imprecise, but they indicate that until CO_2 taxes or cap/trade costs exceed about \$50/ton CO_2, coal units without capture (and paying a CO_2 tax) will be dispatched ahead of coal and natural gas units with capture. Other factors, such as subsidies paid to units that capture CO_2 and improvements in the technology, could certainly impact these results dramatically. For perspective, S.1766 (Senator Bingaman's climate change bill), which becomes progressively more stringent over time, begins with a "safety valve" price of 12 \$/ton CO_2 in 2012, and reaches \$50/ton in about 2040.

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[21] For example, most simplistic analyses of technology options assume a constant level of power generation (or capacity factor) across technology alternatives. In practice, however, utilities operate most those units with the least variable costs (which include fuel consumption and variable operation and maintenance costs). If these variable costs increase markedly for some technology options, then the assumption of constant generation across technology alternatives is incorrect, and the resulting COE calculations are likewise in error because fixed costs (such as capital costs) must now be paid with fewer kilowatt-hours of generation.

[22] *Op.Cit.*, Cost and Performance Baseline for Fossil Energy Plants.

A key parameter in these cost comparisons is the cost of replacement power for the CCS system. Replacement power is estimated to be about 30% of the total plant generation for a pulverized coal system, and about one-half that for a natural gas combined cycle (NGCC) system. Who provides the replacement power is also important to dispatching costs. If the power is purchased from another utility, then its costs can be taken entirely as variable costs. If the replacement power is generated by the same utility that is retrofitting the CCS system, then only its variable costs are included in the dispatching costs for the retrofit system. Dispatching costs for this latter case ("self-generation" of replacement or parasitic power) are presented in Figure 5. This differential effect of who supplies the replacement power can be seen in comparing Figures 4 and 5.

The coal-based systems with CCS show a significant reduction in dispatching costs for the "self-generated" replacement power case (Figure 5), relative to the "purchased power" CCS case (Figure 4). Note that the break-even point for coal systems "paying the tax" versus retrofitting CCS has shifted from a tax level of \$50/ton CO_2, to \$20/ton CO_2 for the self-generated replacement power scenario. The NGCC systems are not as sensitive to the source of the replacement power, because most of the cost of NGCC power is the fuel cost, which is a variable cost in either scenario. For the self-generated replacement power scenario, the dispatching costs for a pulverized coal unit retrofit with CCS is about 40-50 \$/MWh over a range of carbon taxes, which makes it comparable to NGCC systems without CCS retrofits. The take-home message here is not the absolute values of these projected costs, but rather the fact that analysts and decision-makers must be careful regarding how these costs are evaluated, and ensure that the assumptions used are appropriate for the system being evaluated, or they can be seriously misled.

A related factor is the impact of parasitic power needs on bulk transmission of electric power to regions that are traditionally "net importers" of power. If a utility has generation capability that exceeds its local needs, it generally tries to sell that power to neighboring power consumers that have insufficient self-generation capacity. If local excess power is eliminated by retrofitting CCS systems on existing coal (and gas) power plants, then those utilities that previously purchased the excess power will quite likely lose that source of electricity. Hence, the sudden broad deployment of the current generation of CCS technology could be disruptive to power systems that do not even operate fossil fuel-fired generators.

Carbon dioxide transport and storage

The cost and performance aspects of carbon dioxide transport and storage are well covered in the literature.[23] The important factors related to transport and storage are:

1. The cost of transport and storage are believed to be a small fraction of the capture costs.
2. There is experience with pipeline transport and injection/storage at relatively small scale, but no experience with storage at the scale of commercial coal-fired power plants (e.g., 3 million metric tons per year for a single 500 MW unit). DOE is now beginning a program for evaluating "1 million TPY" demonstration projects, but results are years away.
3. There is no environmental regulatory framework for addressing the injection and storage of CO_2 in the most likely resource for coal-fired power plants: saline geological formations perhaps one mile below the surface. EPA recently announced its intent to begin development of such a program under the Underground Injection Control program (UIC). See APPA paper on the current UIC program posted at http://www.appanet.org/files/HTM/ccs.html
4. There is likewise no framework for addressing financial liability associated with CO_2 storage. Existing insurance mechanisms are not practical for a system that must maintain its

[23] *Op.Cit.*, Carbon Dioxide Capture and Storage, Chapters 4 and 5.

integrity for hundreds of years. It is unlikely that electric utilities will embrace CCS technology until pragmatic frameworks are established.

Regulatory Issues for Retrofits

Clean Air Act Permits and Federal New Source Review Issues

Aside from the obvious regulatory issues associated with CO_2 capture and storage that include permitting underground injection wells and obtaining rights to underground caverns for disposal,[24] it also is likely that the retrofit of an existing electric generating unit will result in the retrofit being deemed a "major modification of a major Clean Air Act-regulated source."[25] This is because the CO_2 capture system may lead to increases in other pollutants regulated under the Clean Air Act. Major modifications are subject to the federal new source review (NSR) program, which includes lengthy permitting, modeling of air quality impacts, and installation of state-of-the-art pollution control equipment on the retrofitted boiler and ancillary emitting equipment. Under current federal law even environmentally beneficial projects can be subjected to lengthy regulatory processes, public scrutiny which can include legal challenges, and additional costs deriving from analytic requirements for permit preparation and additional pollution controls. It should be noted that NSR may be required for SO_2 and NOx retrofits installed pursuant to the 2005 Clean Air Interstate Rule (CAIR) because the SO_2 and NOx pollution control equipment may lead to small increases of pollutants other than SO_2 and NOx.[26]

However, even if the NSR exemption for "pollution control projects" still existed[27], typical retrofits to existing power plants likely still would require NSR review. The large parasitic power requirements of CCS technology will very likely lead to increases in coal use at existing units.[28] For some pollutants, like SO_2, the additional reduction of that pollutant that occurs as part of the CO_2 capture process will negate the increased amount of combustion. For others, like particulate matter, the situation is not as clear. In addition, some of the components of the CO_2 capture

[24] It is important to note that in some states, ownership of surface rights does not convey ownership of subsurface mineral or other rights needed for the disposal of carbon dioxide underground.

[25] This term "major modification of a major source" has been the subject of extensive historical and ongoing regulatory and litigation controversy. This paper does not attempt to unscramble or recount these controversies, but instead calls to the reader's attention that caution and additional costs associated with federal (and state) Clean Air Act permits will be associated with CCS retrofits.

[26] See, for example, Clean Air Report, Inside EPA, September 20, 2007, p.1; and New Source Review for CAIR and CAMR Projects, August 24, 2007 draft proposal by Indiana agency representatives to the Environmental Council of the States (not adopted by ECOS).

[27] The D.C. Circuit Court of Appeals held that EPA could not exempt pollution control projects from New Source Review regulations, *New York v. EPA*, 413 F.3d 3 (D.C. Cir. 2006).

[28] Consider the following simplistic example. An existing coal-fired power plant operates 60% of the year at full load, 30% at half-load, and is down for maintenance 10% of the year. After retrofit for CCS, the amount of coal used (and emissions) are unchanged for the full load and no load portions of the year. But for the 30% of the year historically run at half load, assuming demand remains the same and ignoring dispatching economics, to produce the same amount of megawatt-hours the unit will have to operate at approximately 70% capacity factor due to parasitic power loss. This higher operating level would lead to greater uncontrolled emissions. Increases in operating hours are not an exclusion from NSR if the increase is a direct result of a physical change at the unit. The ultimate determination of whether these circumstances constitute a "major modification" would depend on how State, EPA, and the courts interpret the regulations, as well as possible emission mitigating measures that the retrofit facility might undertake.

system may be sources of fugitive emissions of various pollutants regulated under the Clean Air Act.

NSR Review of CO_2 and Other Green House Gases (GHG)

CO_2 and other GHG also are likely to be regulated NSR pollutants for purposes of NSR review by the end of 2008 pursuant to a decision by the United States Supreme Court that these emissions were Clean Air Act "pollutants."[29] EPA officials announced at the September 2007 meeting of the federal Clean Air Act Advisory Committee that the agency intended to complete regulations limiting CO_2 and five other GHG from motor vehicles and possibly refineries by the end of 2008. The regulation of CO_2 under Clean Air Act requirements (except as a "hazardous air pollutant"[30]) renders these substances a "regulated air pollutant" for purposes of New Source Review and Federal Operating Permits under 40 CFR subparts 51, 52 and 70 (the NSR and Part 70 Operating Permit regulations). EPA officials also announced that they intend to undertake an NSR rulemaking by the time GHG are regulated to define what a "major source" of GHG is, and even more importantly, what "significant increases" of GHG are for purposes of defining the term "major modification."[31]

Assuming CO_2 and other GHG become regulated air pollutants, a significant net increase of any GHG within the facility will trigger NSR. This creates a situation analogous to the previously discussed paradox where environmentally beneficial hardware installed to reduce SO_2 and NOx emissions under the CAIR rule could trigger NSR requirements due to small associated increases in particulate matter emissions. Similarly, the retrofit of <u>traditional</u> pollution control devices, like SO_2 scrubbers, also could trigger "major modification" status for that facility for <u>CO_2</u>, in the absence of the now-defunct "pollution control exemption". This would lead to case-by-case Best Available Control Technology (BACT) reviews for CO_2 emissions.

Reconstruction and Clean Air Act New Source Performance Standards

If a facility retrofit constitutes a "reconstruction" of a facility under the Clean Air Act's New Source Performance Standards (NSPS) regulations, the owner or operator must meet NSPS for the "affected source." Thus, it is important to examine how EPA has interpreted the term,[32] defined in the regulations as:

> 40CRF60.15 (b) "Reconstruction" means the replacement of components of an existing facility to such an extent that:
>
> (1) The fixed capital cost of the new components exceeds 50 percent of

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[29] In *Massachusetts v. EPA U.S. 127 S.Ct.1438, 75 USLW 4149* (April 2, 2007), the Court addressed Massachusetts and other states' petition challenging the agency for failing to regulate GHGs under the Clean Air Act's mobile source program. The Court determined that these substances were "air pollutants" under the Act and essentially held that EPA must regulate vehicular emission of CO2 unless the Agency determines that CO2 does not endanger the public's health and welfare. EPA is expected to regulate CO_2 emissions from mobile sources, and that regulation will likely trigger requirements for new or modified major stationary sources such as power plants if they have more than *de minimis* increases in CO_2 emissions.

[30] Note that if CO2 were regulated as a hazardous air pollutant under Title III of the Clean Air Act, PSD would not apply pursuant to section 112(b)(6).

[31] Until EPA defines what a "significant emission increase" is under 40 CFR §§51.166(b)(23) and 52.21(b)(23 of the NSR regulations, *"any"* increase of pollutants will trigger NSR (and BACT) review.

[32] EPA interpretations of NSPS for various affected industries can be searched on the Office of Enforcement and Compliance website on the "Applicability Determination Index" at http://cfpub.epa.gov/adi/.

the fixed capital cost that would be required to construct a comparable entirely new facility, and

(2) It is technologically and economically feasible to meet the applicable standards set forth in this part.

(c) "Fixed capital cost" means the capital needed to provide all the depreciable components.

Since the addition of a capture system does not fit neatly into the concept of "replacement of components," the applicability of the NSPS "reconstruction" test to CCS is unclear, in part because it is not clear whether the cost of a "pollution control" is included in determining the cost of a facility replacement." Also, "pollution control projects" (PCPs) and "clean coal technology" continue to be exempt from the NSPS definition of "modification" under 40 CFR §60.14(e)(5), even following a Court's ruling that the NSR exemption for PCPs was illegal because it might cause an increase in actual emissions.[33] Nevertheless, even if all of these conditions are met, a regulatory obligation for reconstruction based on CO_2 emissions can only exist after EPA adopts a CO_2 NSPS, under 40 CFR Part 60. Note, that this future rulemaking could create a preference for an oxy-fueled system versus a post-combustion system, depending on how the rules are specified.

Storage Rules

There is general recognition that the current underground injection control (UIC) program for waste injection is not well designed to address issues associated with CO_2 storage in deep saline reservoirs. The Interstate Oil and Gas Compact Commission (IOGCC) recently proposed that states take the lead on this type of regulation, given their extensive regulatory experience with CO_2 -based enhanced oil recovery.[34] Moreover, IOGCC expressed the view that CO_2 should be treated as a resource, rather than as a waste, and that treatment of CO_2 as a waste "would diminish significantly the potential to meaningfully mitigate the impact of CO_2 emissions through geologic storage." Shortly after IOGCC's report and announcement calling for state primacy, U.S. EPA announced that it was beginning a federal rulemaking, under the authority of the Safe Drinking Water Act, to address underground injection of CO_2.[35]

Another local consideration that needs to be considered in the context of CCS is the ownership of surface and subsurface rights. In certain states (and most with significant mineral rights), ownership of underground caverns may be distinct from ownership of surface rights. Careful examination of deeds and other land records may be necessary to establish property ownership and rights of way for transport and sequestration of gases.

[33] *New York v. EPA*, 413 F.3d 3 (D.C. Cir. 2005).

[34] Storage of CO_2 in Geologic Structures – A Legal and Regulatory Guide for States and Provinces, IOGCC, September 25, 2007. "*A key conclusion of that report* [a 2005 IOGCC study] *was that given the jurisdiction, experience, and expertise of states and provinces in the regulation of oil and natural gas production and natural gas storage in the United States and Canada, the states and provinces would be the most logical and experienced regulators of the geologic storage of carbon dioxide.*"

[35] "EPA Rulemaking Plan May End States' Bid for Lead Role On CO_2 Storage", Inside EPA, October 12, 2007, citing an Oct 11 announcement by EPA Administrator Stephen Johnson.

Other liabilities
Two additional areas of risk management related to CO_2 storage are:

1. The potential for stored CO_2 to migrate into areas of other valued resources, such as natural gas deposits, and diminish the value of those resources; and
2. The potential for CO_2 migration after closure of the injection site. Injection of CO_2 from an operating plant may last for decades, but for the storage to be effective, the CO_2 must be contained for centuries. This timeframe is beyond the scope of available commercial risk management issues.

Effectively managing these risks may require government participation, and that may require additional legislative authority.

Looking to the future

There is much ongoing activity related to CCS. The Department of Energy is focusing on both capture and storage, and several large storage projects are starting under the Regional Partnerships program. As noted earlier, EPA is beginning to develop rules for CO_2 storage, and initial regulatory responses to *Massachusetts versus EPA* are likely by the end of 2007. Climate change mitigation legislation is receiving much attention in Congress.

Nevertheless, given the significant contribution of existing coal-fired power plants to both the nation's electricity supply and to national greenhouse gas emission rates, and the high cost of currently available mitigation techniques, the resources focused specifically on developing pragmatic solutions for this CO_2 emission group seem quite limited. Additional effort appears warranted to:

- Significantly drive down the cost of CO_2 capture, both through "learning by doing" using current technology, and through additional research.
- Explore ways to modify the existing power plant itself, such as replacing turbines or turbine components, or upgrading boilers, so that the existing plant becomes more efficient and productive. This would provide both a partial cost offset to the increased cost of electricity due to CCS retrofit, and (possibly) reduce the impact of parasitic power needs to drive the CCS hardware.
- Gain experience with storing large quantities of CO_2 in different types of geologic saline structures. The Regional Partnerships program may be a good start, but a few large projects are unlikely to be representative of the full range of geologies in the U.S. that are attractive for CO_2 storage
- Increase our knowledge base and simplify traditional preconstruction permitting procedures to expedite the permitting of CCS retrofit projects.

About the author – Doug Carter is an independent consultant on energy technology and related environmental issues. His current practice focuses on advising clients regarding advanced coal-based technologies and their potential role in mitigating global climate change. Mr. Carter's resume includes 25 years with the U.S. Department of Energy, where he was Director of the Office of Planning and Environmental Analysis, within the Office of Fossil Energy. He had previously served with the Office of Enforcement and Office of Air Quality Planning and Standards at the U.S. Environmental Protection Agency. Mr. Carter holds degrees in Mechanical Engineering and Environmental Engineering. He can be reached at Carter2250@comcast.net .

The American Public Power Association is the national service organization representing the nation's more than 2,000 community- and state-owned electric utilities. APPA's website is www.appanet.org The dedicated website address for information on geologic sequestration and carbon capture and geologic sequestration or storage is:
http://www.appanet.org/files/HTM/ccs.html
APPA Contact: Theresa Pugh, Director, Environmental Services, 1875 Connecticut Ave, NW, Suite 1200, Washington, D.C. 20009-5715 or at (202) 467-2943

See page 13-16 for figures

Figures

Figure 1. Pulverized coal power plant with carbon capture.

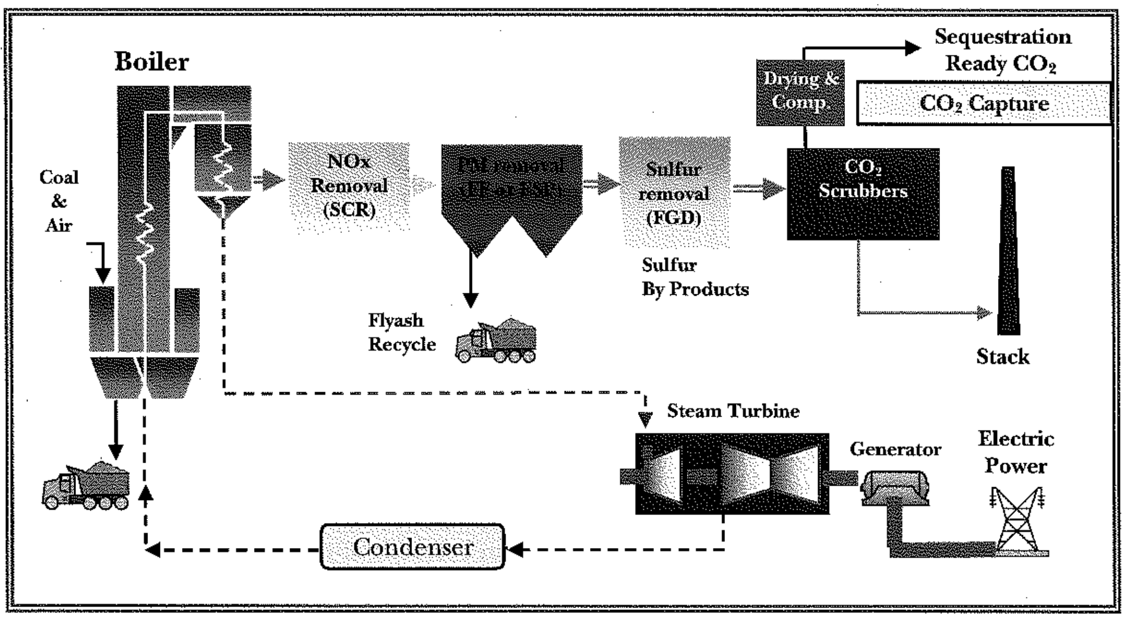


Figure 2. Sources of parasitic power.

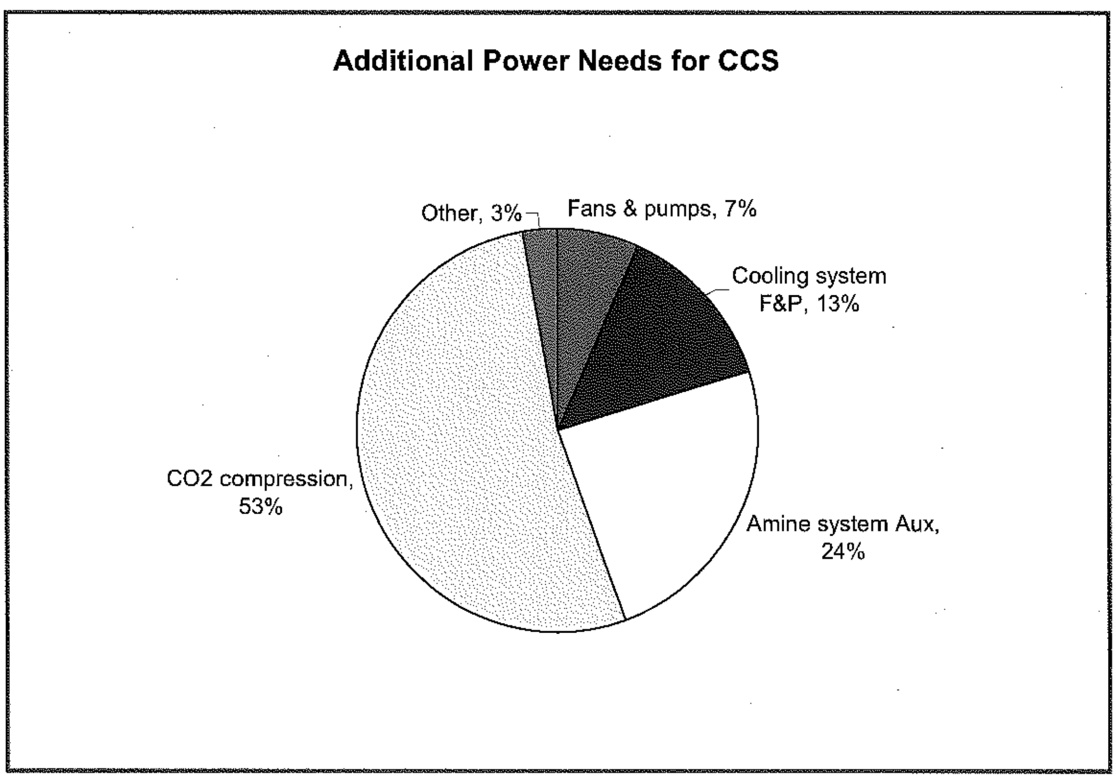


Figure 3. An Oxy-combustion unit with CO2 capture.

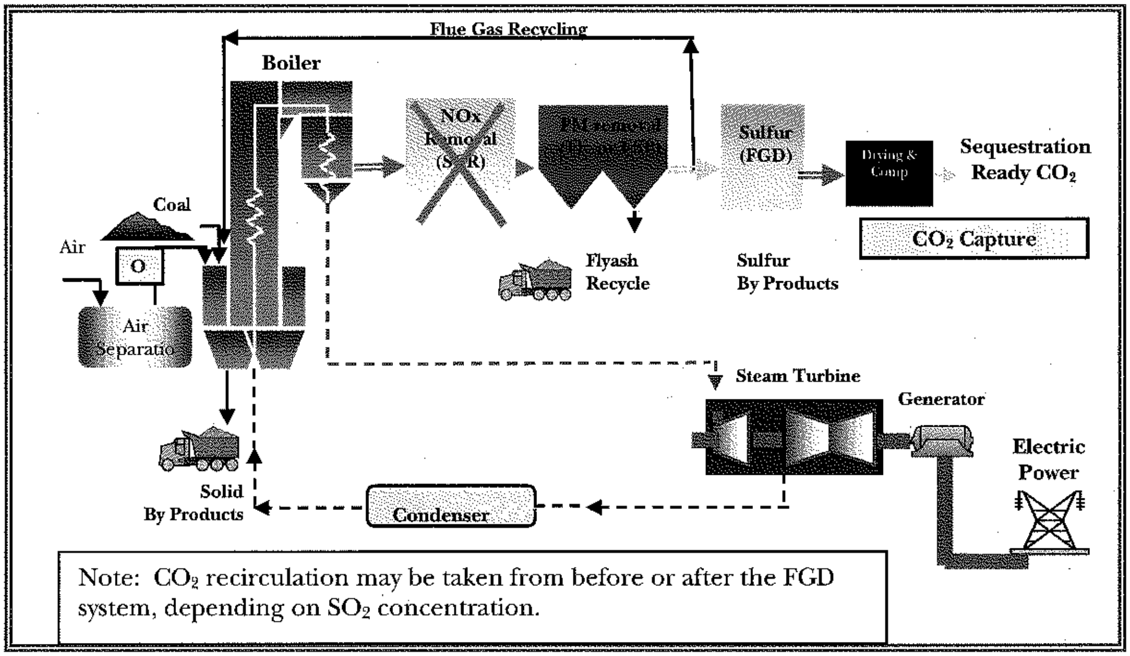


Figure 4. Dispatching costs assuming replacement power is purchased.

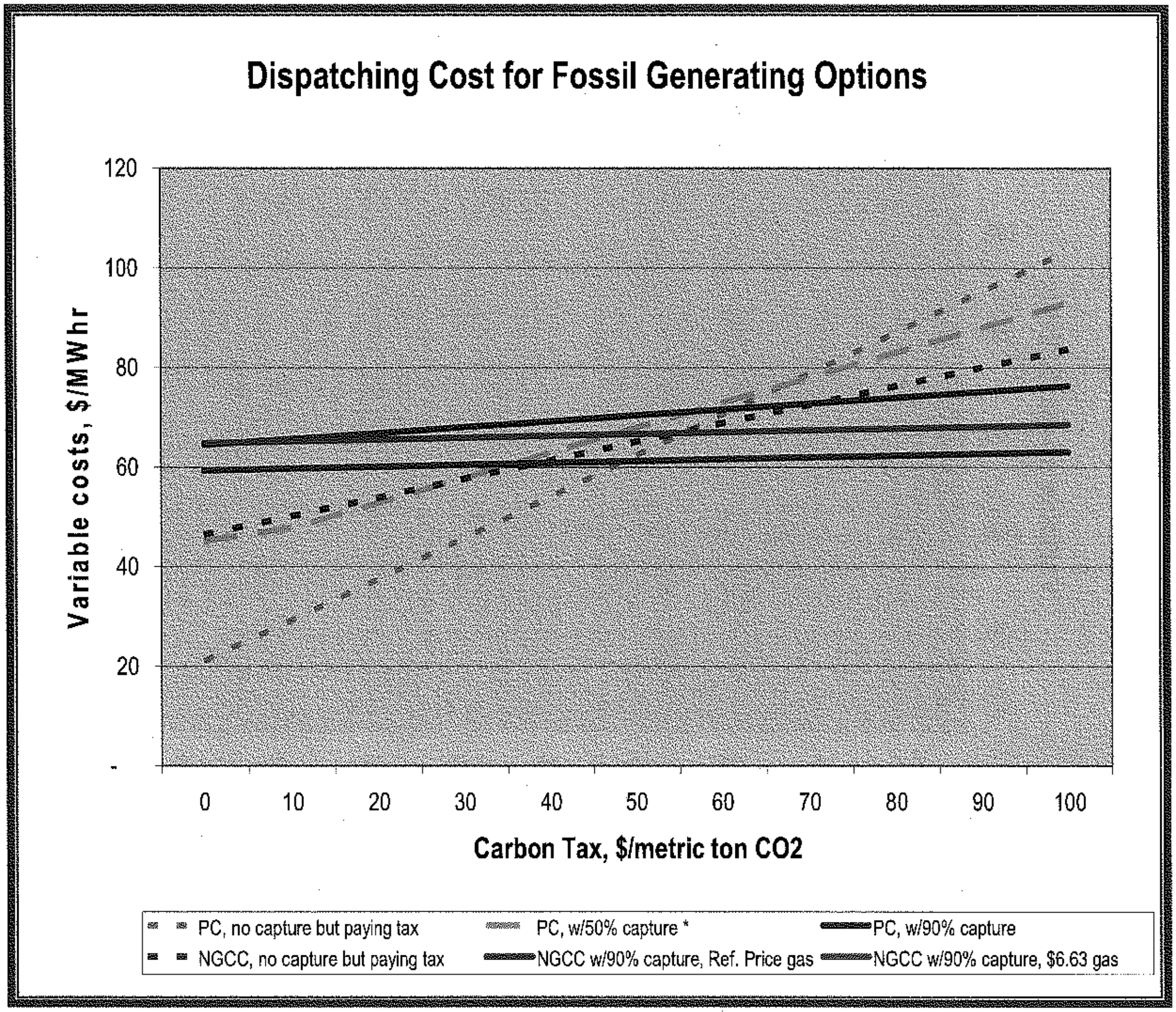
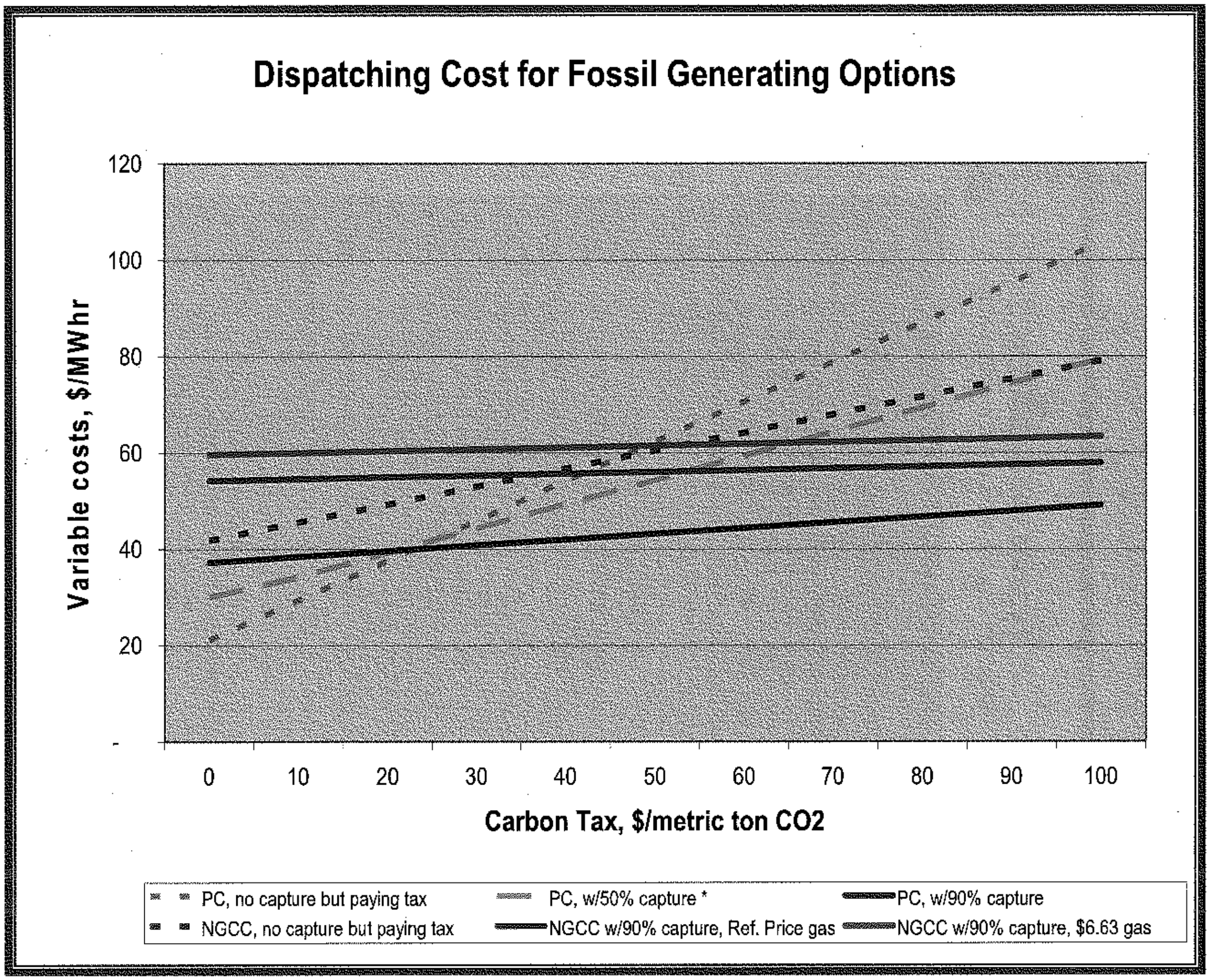


Figure 5. Dispatching costs assuming self-generated replacement power.



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Carbon Capture and Storage From Coal-based Power Plants: A White Paper on Technology for the American Public Power Association (APPA)

L.D. Carter

May 22, 2007

Introduction

Technology for carbon capture and storage (CCS) from coal-based electric power plants is rapidly emerging. The component technologies for capture and transport exist, although they are relatively costly compared to other emission control systems (increasing the cost of electricity by over 60%). Technologies for injecting carbon dioxide (CO2) into partially depleted oil reservoirs have been used for enhanced oil recovery (EOR) in the U.S. for over 30 years. Similar techniques have been used since 1990 to inject CO2 into saline reservoirs in Canada, in association with oil and natural gas processing[1]. Additionally, a limited number of power plants have used chemical sorbents to capture CO2 for reuse at very small scale (a few hundred tons per day, or less).[2] However, there is no commercial experience with commercial scale power plants capturing and storing large quantities of CO2 in geologic formations. Additionally, there is no existing regulatory framework that adequately addresses one unique feature of carbon storage: it must be permanent to be effective.

The challenge facing industry, and the regulatory community, is to address the technical gaps in integration of the technologies at hand, move aggressively with research and demonstration projects to significantly reduce the cost of more advanced carbon-controlled systems, build an improved understanding of the long-term behavior of CO2 stored underground, and craft a pragmatic risk management framework for conducting CO2 storage. Increasing the difficulty of this challenge is the fact that all of this must be done simultaneously, with limited resources, and at a time when continuous construction of new power plants is necessary to supply a healthy and growing economy.

[1] Overview of Acid-Gas Injection Operations in Western Canada, S. Bachu, Alberta Energy and Utilities Board, Edmonton, Canada, http://uregina.ca/ghgt7/PDF/papers/peer/588.pdf.

[2] For example: Kerr-McGee/ABB Lummus Crest Process using MEA (Mono-Ethanolamine), Fluor Daniel ECONAMINETM MEA process, Kansai Electric Power Co. / Mitsubishi Heavy Industries, Ltd. (KEPCO/MHI) process using KS-1, KS-2, and KS-3 solvents. Source: Carbon dioxide Capture and Storage, IPCC, 2005, p.116.

This paper will discuss the status of technology to capture CO_2 both from combustion-based and gasification-based power generation fueled by coal, and technologies to transport and store CO_2 in underground (geologic) formations. This paper is not intended to be a technology treatise, but rather to draw from the work of others to present decision-makers in the utility sector and the regulatory sector with an overview of what is practical today and what is possible in the near future.

CO_2 capture from combustion-based coal power plants

Two CO_2 capture approaches are receiving strong interest for application with combustion-based power plants. The first is based on absorption of flue gas CO_2 by an aqueous solvent. CO_2 concentrations in flue gas are modest, 12-15%, due primarily to presence of significant amounts of combustion-air nitrogen, and to "excess" air needed to ensure complete combustion of coal. For these concentrations, chemical sorbents have been shown to be effective at separating CO_2 from the other flue gases, and releasing it in a concentrated stream for further processing. Figure 1 presents a diagram of a conventional pulverized coal power plant, equipped with such a CO_2 "scrubber". Possible solvents include a family of amine chemicals, which are molecular "cousins" to ammonia; proprietary solvents designed specifically to capture CO_2, such as "KS-1" solvent from Mitsubishi Heavy Industries; and advanced solvent concepts, such as chilled ammonia. For these chemical solvent-based capture systems, the CO_2 is captured in an absorption vessel (amines typically operate at 50 °C (120 °F)). The CO_2-enriched sorbent is then pumped to a second vessel and heated to about 120 °C (250 °F) to drive off a concentrated stream of CO_2 and regenerate the lean solvent. The concentrated CO_2 is dried and compressed to about 2200 psia for pipeline transport in a supercritical state to a site for use or storage. Parasitic power needs are substantial and include pumps, fans, solvent regeneration, and CO_2 compression. In addition, the CO_2 solvents tend to form "heat stable salts" with any remaining SO_2 or NOx in the flue gas. These stable salts do not break down in the solvent regenerator, so there is loss of solvent unless SO_2 and NOx are reduced to extremely low concentrations. These factors combine to lead to a 25% increase in fuel consumption per kilowatt-hour generated, and increase cost of electricity by over 60%.[3]

Looking to the future, an absorption process using ammonia is under development by Powerspan, and will be tested on a slipstream from First Energy's 50 MW Burger plant in 2007 and 2008. Alstom and EPRI will test a chilled ammonia system at a 5 MW scale at WE-Energy's Pleasant Prairie station in 2007. AEP has signed a memorandum of understanding to test the technology at the Mountaineer Plant in West Virginia in 2008, and if successful, at the Northeastern Station in Oklahoma in 2011, for use with enhanced oil

[3] Carbon Dioxide Capture and Storage, IPCC, Chapter 3, 2005.

recovery.[4] Ammonia is lower cost, has higher levels of CO_2 absorption, and requires less energy for regeneration than currently used chemical solvents, so success in these technologies could reduce the cost and energy penalty of CO_2 capture at conventional power plants.

Oxy-combustion is a second approach to capturing CO_2 from pulverized coal power plants, and takes a radically different approach than CO_2 absorption. With oxy-combustion, the coal is burned with pure oxygen, not air, so the products of combustion are primarily CO_2, water vapor, and some excess oxygen (see Figure 2). To moderate boiler temperatures to about 1900 °C (3450 °F), it is necessary to recirculate a portion of the flue gas CO_2 (downstream of the particulate matter control system) back into the boiler. Particulate matter must be removed as usual, but nitrogen oxide formation is very low so the traditional selective catalytic reduction (SCR) system is unnecessary. The SO_2 system can be significantly downsized because it does not process the flow of excess air or nitrogen normally encountered with air-based combustion. The CO_2 capture system consists essentially of gas drying and compression, although some additional gas purification may be needed. This design approach can take advantage of higher temperatures and improved heat transfer from CO_2/H2O mixtures to allow a more compact (cheaper) boiler. Parasitic energy demands are high (e.g., 25%), because of the oxygen plant and CO_2 compression. None of these systems has been operated at a commercial scale, although most of the component technology is commercially available.

Looking to the future, AEP has announced its intent to conduct a pilot demonstration of oxy-combustion in Summer 2007, followed by retrofit to an existing commercial coal-fired unit by 2015.[5] In addition, DOE is working with Air Products and Chemicals, Inc., to develop an Ion Transport Membrane approach for producing oxygen, to replace the conventional cryogenic oxygen plant, thereby reducing the cost and energy required for oxygen production.[6]

CO_2 capture from IGCC

A different approach to CO_2 capture is associated with Integrated Gasification Combined Cycle (IGCC) power plants. In a conventional IGCC, coal is gasified to produce synthesis gas (primarily hydrogen, carbon monoxide, and carbon dioxide), which is then treated to remove contaminants and burned in a combustion turbine, which drives a generator to produce power. Hot exhaust gases from the combustion turbine are moved through a heat recovery steam generator to produce steam, which is expanded through a steam turbine and

[4] Corporate Citizenship, the role of technology, AEP news release, http://www.aep.com/citizenship/crreport/climatechange/theroleoftechnology.asp .
[5] Ibid.
[6] Development of Ion Transport Membrane Oxygen Technology for Integration in IGCC and Other Advanced Power Generation Systems, NETL project factsheet #136, May 2006, http://www.netl.doe.gov/publications/factsheets/project/Proj136.pdf .

generates additional power (hence, the term "combined cycle"). Rather than capture the CO_2 at the end of this process, in an IGCC CO_2 is captured prior to combustion of the synthesis gas. This is possible because the synthesis gas can be reacted with water in a catalytic "shift reactor" to convert most of the carbon monoxide to hydrogen and CO_2. This leaves a modified synthesis gas consisting largely of hydrogen, water vapor, and CO_2, still under the relatively high pressure created in the gasifier. CO_2 is much easier to separate in this concentrated, pressurized state, than in normal flue gas. Following H_2S removal, a physical solvent process, such as Selexol, can be used to separate the CO_2 from the hydrogen. The CO_2-rich solvent is then pumped to a separate vessel where concentrated CO_2 and lean solvent are regenerated by a reduction in pressure, rather than by the addition of heat as with chemical sorbents (see Figure 3). The hydrogen (instead of CO-rich syngas) is burned in a combustion turbine, and waste heat is used to generate steam which generates additional power, similar to an IGCC without CO_2 capture. The inherent advantage of this power generation approach is that the CO_2 capture system uses much less parasitic power, and costs less than systems designed for pulverized coal power plants. The inherent disadvantage is that the basic IGCC system (without CO_2 capture) remains a relatively immature technology, and costs more than comparably sized pulverized coal system without CO_2 capture. For example, Duke Energy estimates the capital cost of its proposed Edwardsport, Indiana, IGCC to be $1.985 billion for the 630 MW facility, or over $3000/kw.[7] These costs are substantially higher than recent government reports which projected costs for such systems.[8] Complicating this high capital cost is the fact that none of the four existing coal-based IGCCs has met its original design reliability goal with coal. In addition, high-efficiency combustion turbines fueled by hydrogen have not been commercially demonstrated.

It may be possible to reduce the cost of CO_2 capture from IGCC systems, and use generation systems that do not require a hydrogen turbine, by capturing less than 90% of the plant's CO_2. For example, DOE's most recent analysis of IGCC gasifiers indicates that the GE system converts about 30% of the coal carbon into CO_2 in the synthesis gas (the rate for the ConocoPhillips design is about 25%, and the Shell system analyzed was much less).[9] This CO_2 could be captured at lower cost and with much less disruption to the overall plant design that a system including a shift reactor. Alternatively, the gas could be partially shifted, lowering the cost of the shift reaction, and probably leaving enough CO in the syngas to enable use of demonstrated combustion turbines, at the sacrifice of high rates of CO_2 capture. However, neither of these systems has been commercially demonstrated, or even well developed in published technical papers providing

[7] Edwardsport IGCC FEED Study Report, (Redacted Copy), Duke Energy, as filed with the Indiana Utility Regulatory Commission, 2April2007.
[8] Cost and Performance Baseline for Fossil Energy Plants – Updated Technical Performance, DOE/NETL, 10April2007, http://www.netl.doe.gov/technologies/coalpower/refshelf.html .
[9] Ibid.

detailed design or cost estimates. And neither would appear to overcome the basic cost and reliability issues associated with IGCCs without CO_2 capture.

A number of developments that are underway are intended to make IGCC both more reliable and affordable. These include improved refractory, for refractory-lined gasifiers, which should reduce the outage time for rebricking, as well as allow higher gasifier temperatures, which will help carbon conversion; lower cost oxygen production processes (see above discussion of Ion Transport Membranes); warm gas H_2S cleanup, which allows efficiency improvements; dry-feed coal "pumps" for gasifiers to replace lock-hopper approaches, and possibly, slurry feeds; and R&D on hydrogen fueled combustion turbines. Several of these improved system components should be ready for commercial-scale demonstration on the FutureGen system, which is scheduled to begin operation in late 2012.

CO_2 transport

Quantities of CO_2 on the scale of a coal-fired power plant's production (3 million tons per year for a 500MW unit) will almost certainly be transported by pipeline unless injection occurs at the plant site. For pipeline transport, CO_2 is pressurized to a supercritical state that has the low viscosity of a gas, and yet can be efficiently pumped like a liquid. Because of the extensive use of CO_2 for enhanced oil recovery, CO_2 pipelines are a mature technology, and have been operating reliably in the U.S. for over 30 years. There are over 1500 miles of CO_2 pipelines in the U.S., transporting over 50 million tons of CO_2 per year. For example, the Weyburn pipeline carries 5000 tonnes per day of CO_2 (96% CO_2 and 0.9% H_2S) for 200 miles between the Great Plains Synfuels plant in North Dakota and the Weyburn EOR project in Saskatchewan, Canada. Although CO_2 is considered an "acid" gas, as long as the flow is kept moisture free, standard carbon-manganese steels can be used for pipelines.[10] It should be noted that different states have different constraints on the concentrations of non-CO_2 gases permitted in CO_2 pipelines.

Pipeline transport cost is generally not a major component of overall capture, transport, and storage costs. However, pipeline costs vary by the size of the pipeline with significant economies of scale. For example, transport via a 150 mile pipeline for CO_2 from a 500 MW power plant (about 3 million TPY) is estimated to cost about \$3.00 – 5.00/Tonne CO_2, whereas transport for a 2,000 MW facility would cost about \$1.40 – 2.10/Tonne CO_2.[11] An important issue related to pipelines is obtaining right-of-way for the pipeline. Additional legislation may be needed to ensure the ability to construct CO_2 pipelines (eminent domain).

[10] Op.Cit., IPCC 2005, p.182-3.
[11] Op.Cit., IPCC 2005, p. 192; figures are in 2002 dollars.

CO_2 storage

A number of options are available for CO_2 storage. Figure 4[12] presents several of these options, including storage in depleted natural gas or oil reservoirs (which can involve EOR), storage in deep saline structures, and use for enhanced coal-bed methane production. It appears that those storage options that provide a "rebate" on storage, such as EOR, will be insufficient to meet the storage requirements of a program requiring industry-wide capture and storage of CO_2. Additionally, power plants must compete with other, lower cost sources of CO_2, such as CO_2 produced from underground deposits, or CO_2 from natural gas processing plants. Most CO_2 currently used for EOR in the U.S. is from underground deposits, and most of the remainder is from natural gas processing plants. However, it also appears that, at least in the U.S., additional saline reservoirs will be adequate to handle storage needs for hundreds of years of emissions.[13] An important caveat on storage is that the needed geological storage formations are not evenly distributed throughout the U.S. Figure 5, taken from DOE's Sequestration Atlas, shows the distribution of deep saline formations.[14]

In general, the process for injecting CO_2 into geological formations is well understood, having been used for approximately 90 EOR projects worldwide, which cumulatively store about 40 million tonnes per year of CO_2 (compared to about 3 million tons per year (TPY) of CO_2 from a single 500 MW coal-based power plant).[15] The key features separating CO_2 injection for long-term storage versus CO_2 injection for EOR are:

- CO_2 retention is not the primary goal for EOR operations. EOR operations focused on maximizing CO_2 retention would likely follow different procedures.
- With EOR operations, an impermeable caprock is likely associated with the oil deposit. In saline formations, the presence of caprock is presumed if the site is being considered for storage, but the integrity of the caprock has not been established by its ability to retain oil or natural gas over hundreds of thousands of years.
- In EOR situations, the operator's liability generally ends with the decommissioning of the injection well, as demonstrated by the return of surety bonds held by state agencies to assure remediation in the event of a leak.

Leakage of CO_2 from a properly designed and operated storage facility is considered unlikely. The IPCC concluded that "it is considered likely that 99% or

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[12] Op.Cit., IPCC 2005.
[13] Carbon Sequestration Atlas of the U.S. and Canada, USDOE/NETL, March 2007.
[14] Ibid.
[15] Discussion Paper For 2nd IEA/CSLF Workshop on Legal Aspects of Storing CO2 (draft), International Energy Agency, 17October2006.

more of the injected CO_2 will be retained for 1000 years."[16] However, if leakage occurs, it can be a serious matter. Figure 6 displays various pathways by which CO_2 can escape storage.[17] The most commonly stated concern is leakage via existing oil or gas wells that might penetrate the caprock near the CO_2 injection site. It is commonplace in oil producing regions to "discover" wells long since abandoned and forgotten. Mitigation is straightforward: plug the well at a cost of $15,000 - $25,000.

Although relatively low concentrations of CO_2 are essential for the support of plant life, concentrations over 50,000 ppm have been shown to cause impairment of mental processing, and death is possible from exposure to concentrations exceeding about 10% CO_2. Volcanic leaks leading to soil root concentrations of 20-30% CO_2 have killed trees at Mammoth Mountain, California.[18] If CO_2 escaped a deep saline reservoir, it might also migrate into a more shallow fresh water aquifer, and there is concern that the acidic nature of CO_2 could mobilize metals that would harm such aquifers. It should be noted that no leakage or safety incident has been reported for the Canadian acid gas injection program, which has been operational since 1990.[19]

The FutureGen project implemented a comprehensive above ground and below ground site analysis for all sites being considered for the project.[20] Three types of criteria were considered:

- Qualifying criteria, which were required to be fully met.
- Scoring criteria that involve a numerical evaluation, but did not have to be met 100%. There were 261 such criteria.
- "Best value" criteria, which were non-quantitative, but important to the goals of the project.

This type of comprehensive analysis is a useful template for the next generation of CO_2 storage projects. Site selection will follow an extremely cautious approach until much more experience has been gained with this technology.

In a report on regulatory needs related to carbon capture and storage (CCS), the Interstate Oil and Gas Compact Commission (IOGCC) concluded that most aspects of CCS were adequately addressed by existing regulatory frameworks, but that post-injection monitoring and risk management needed additional attention.[21]

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[16] Op.Cit., IPCC, p.197.
[17] Op.Cit., IPCC, p. 243.
[18] Lessons Learned from Natural and Industrial Analogues for Storage of CO2 in Deep Geological Formations, S. Benson, et.al., Lawrence Berkeley National Laboratory, March 2002.
[19] Op.Cit., Bachu.
[20] Results of Site Offeror Proposal Evaluation, FutureGen Alliance, 21July2006.
[21] Carbon Capture and Storage: A Regulatory Framework for States, Interstate Oil and Gas Compact Commission, January 2005.

EPA has issued guidance applicable to pilot-scale CO_2 injection projects, such as those being conducted by the DOE Regional Partnerships program. However, the guidance was clear in stating that it did not extend to commercial-scale projects, and implied that projects storing both CO_2 and other materials like SO_2 or H_2S would face additional, unstated requirements.[22] It is reasonable to expect that EPA will eventually adopt regulations governing CO_2 injection for non-EOR purposes, probably under the Underground Injection Control (UIC) program. Until then, however, commercial scale projects will be regulated on a case-by-case basis, using current UIC regulatory authority. One can assume an abundance of caution will accompany early commercial projects, which could impact both the cost of the storage project and the time needed for obtaining necessary permits.

It should be noted, particularly in light of the IOGCC report, that there is no existing legal framework within which to address the long-term liabilities associated with CO_2 storage. The timeframes for storage integrity exceed normal life cycles for corporations, and insurance instruments for such long periods have no "actuarial" basis for calculating appropriate fees. It seems likely that this gap will have to be filled, probably by a system of sharing liability between the private and public sector, before most entities will be willing to embrace non-EOR CO_2 storage projects.

Costs

We are in a period of rapid cost changes for major construction projects such as power plants. Therefore, any generic cost estimate must be taken as establishing an approximate value. The following capture cost estimates are taken from an April 2007 DOE/NETL report[23]; pipeline and injection costs are taken from an IPCC report[24], and adjusted to 2007 dollars using the Chemical Engineering plant cost index.

- Capture and compression, new IGCC: \$30-40 \$/tonne CO_2 avoided.
- Capture and compression, new SCPC w/ amine scrubber: 69 \$/tonne CO_2 avoided
- 150 mile pipeline, 12 million tonne per year capacity (~ 2000 MW): 1.80 – 2.70 \$/tonne CO_2. Costs per tonne approximately double for a pipeline capacity of 3 million tonne per year.
- Injection: Saline formation, 0.50 – 5.80 \$/tonne CO_2
- Injection: Depleted oil field, 0.65 – 5.20 \$/tonne CO_2
- Injection: Depleted gas field, 0.65 – 15.70 \$/tonne CO_2

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[22] Using the Class V Experimental Technology Well Classification for Pilot Geologic Sequestration Projects – UIC Program Guidance (UICPG #83), From C. Dougherty & B. McLean (EPA HQ), to Water management Division Directors and Air Division Directors, EPA Regions I-X, 1March2007.

[23] Op.Cit., DOE/NETL 2007, p.36.
[24] Op.Cit., IPCC 2005, p.192, 260.

The approximate value of CO_2 purchased for EOR might range from 1-2 $/thousand standard cubic feet, or about 18-36 $/tonne CO_2, and varies with the price of oil.

Several caveats are essential for proper interpretation of these cost estimates.

1. It must be emphasized that they apply to a new facility, where there is freedom of design. Retrofitting would amplify costs not only due to space limitations, less likelihood of proximity to storage geology, and generally lower "beginning" plant efficiency (which exacerbates the impacts of parasitic power consumption), but also due to hardware issues such as the inability to easily extract steam for CO_2 sorbent regeneration.
2. The apparent lower cost of capture from IGCC, compared to SCPC, is significantly offset by the higher cost of the IGCC system without capture, compared to SCPC without capture. If both systems with capture are compared to a SCPC system without capture, the overall impact of capture and pressurization (without the transport and injection) is typically in the range of a 60-70% increase in the levelized cost of electricity.
3. The DOE estimates are for bituminous coal-based systems. Most studies conclude that capital costs are higher for both IGCC and SCPC systems on subbituminous coals, but the increase is greater for IGCC units.
4. One should not assume that power plants built near old oil or gas fields will enjoy a large "rebate" from CO_2 sales for oil or gas recovery. A number of existing industrial processes produce voluminous supplies of relatively pure CO_2 which are already separated from other gases.[25]

Probably most important, is the fact that no power plant in the world has demonstrated CO2 capture, transport, and storage in saline reservoirs. Such demonstrations are several years away. Pieces of the puzzle have been solved, but no one has yet assembled the entire puzzle. Moreover, it would seem very prudent to take the time to evaluate the technology at commercial scale before embarking on large scale deployment, regardless of how the costs look.

It is very likely that additional RD&D will reduce the cost of CO_2 capture and compression, perhaps significantly. However, pipeline and injection systems use relatively mature technologies and are not likely to enjoy such declines over time.

[25] Natural gas processing plants, for example, often process raw gas that is too high in CO_2 for sale to pipelines, so the CO_2 is separated and vented to the atmosphere. As noted earlier, this gas is available and much cheaper to capture than CO_2 from power plants, and natural gas processing plants are usually in the vicinity of gas and oil fields. It is not coincidence that most of the CO_2 now used for EOR that is not from natural deposits comes from natural gas processing plants. In a carbon constrained world, it is reasonable to assume that these processes will need to find storage for their emissions, and that the value of CO_2 will drop as more emitters seek to sell their CO_2.

Summary: Key issues requiring additional attention

With respect to CO_2 capture from coal-based power plants, the major issues are technology integration and costs. CO_2 capture from conventional power plants has occurred only at a very small scale (a few megawatts), and without integration with storage systems. Integration requires development of systems to address malfunctions in the carbon capture/compression/transport/or storage system. Cost barriers at new conventional pulverized coal power plants suggest that much cheaper sorbent systems, or lower cost oxygen production systems will be needed to avoid a major increase in power costs. Retrofit systems present additional issues that exceed the scope of this paper.

For gasification-based systems (IGCC), the major challenges are the relatively high cost of the IGCC itself, absent CO_2 capture, and concerns regarding reliability. In addition, for 90% CO_2 capture, the resulting fuel for the combustion turbine will be almost all hydrogen, and high efficiency combustion turbines fueled with hydrogen have not been commercially demonstrated.

Transport and injection of CO_2 are relatively mature technologies. But we have very limited experience with the fate of CO_2 injected in non-EOR applications at rates of 3 million TPY or more (comparable to a 500 MW coal-based power plant). We will need several multi-year research projects, at commercial scale, in which injected CO_2 is carefully monitored, to gain the necessary understanding of what happens to such CO_2 volumes over long periods of time. And it must be emphasized that not all areas of the U.S. are proximate to attractive storage formations.

As a final caveat, it should be noted that people often fear what is not well understood, and CO_2 storage is not well understood by the general population, or by government bodies that regulate power plants. It would not be particularly challenging for groups opposed to coal use in general to generate public opposition to plants pursuing CCS technology, or unexpected for regulators to impose overly onerous requirements in an abundance of caution. The next few years will be a critical period during which we must both exercise due caution and yet embrace projects that will develop commercial scale knowledge about these technologies. Aggravating this situation is the lack of a system to manage CO_2 storage sites decades after injection has been completed. The most obvious solution to this social/regulatory barrier is to immediately develop an interim regulatory plan, covering a limited set of pioneer plants that are injecting large volumes of CO_2, to apply until we can generate the data needed to support a permanent regulatory framework for broad deployment of this technology.

About the author – Doug Carter is an independent consultant on energy technology and related environmental issues. His current practice focuses on advising clients regarding advanced coal-based technologies and their potential role in mitigating global climate change. Mr. Carter's resume includes 25 years with the U.S. Department of Energy, where he was Director of the Office of Planning and Environmental Analysis, within the Office of Fossil Energy. He had previously served with the Office of Enforcement and Office of Air Quality Planning and Standards at the U.S. Environmental Protection Agency. Mr. Carter holds degrees in Mechanical Engineering and Environmental Engineering. He can be reached at Carter2250@comcast.net .

Figures

Figure 1. Conventional PC with post-combustion capture.

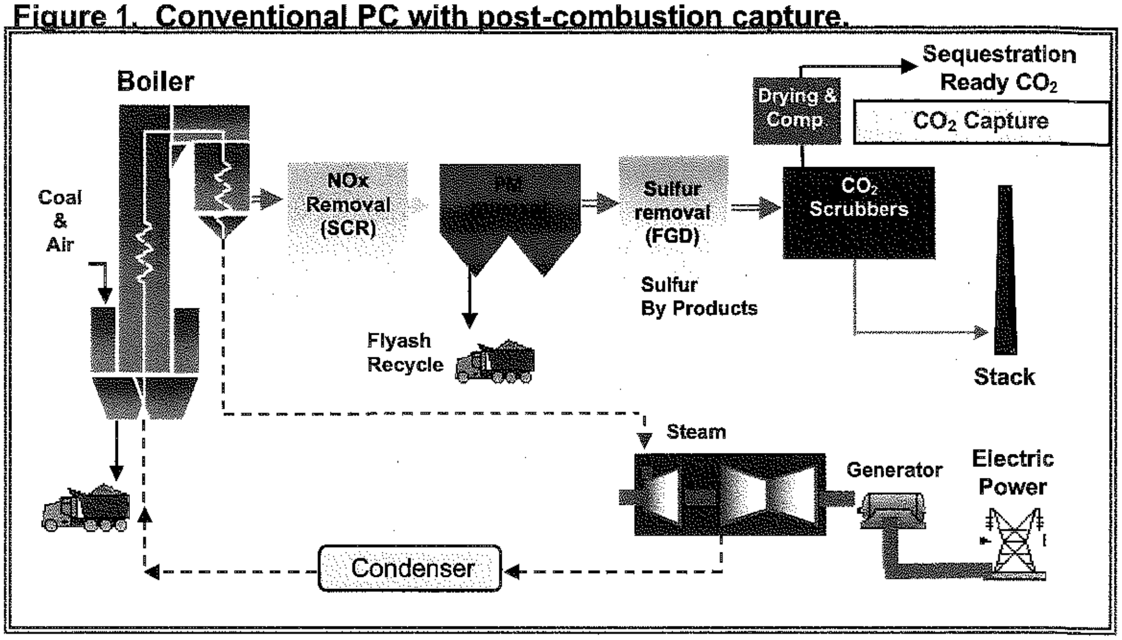

Figure 2. Oxy-combustion system with CO_2 capture.

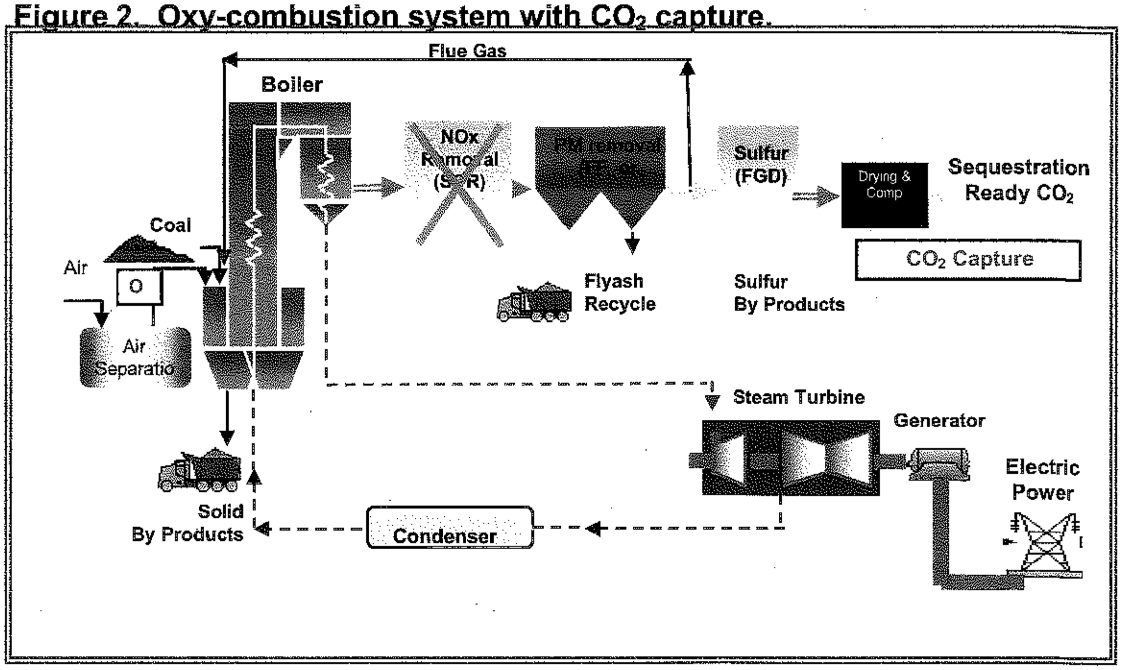

Figure 3. IGCC power plant with CO_2 capture.

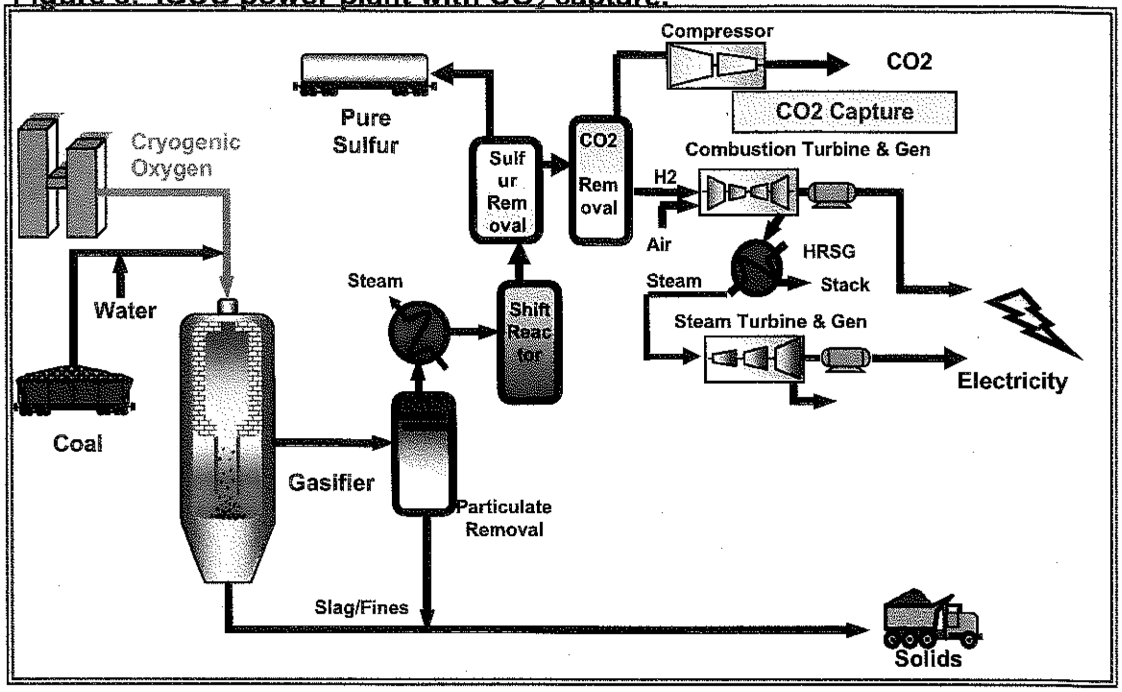

Figure 4. CO_2 storage options.

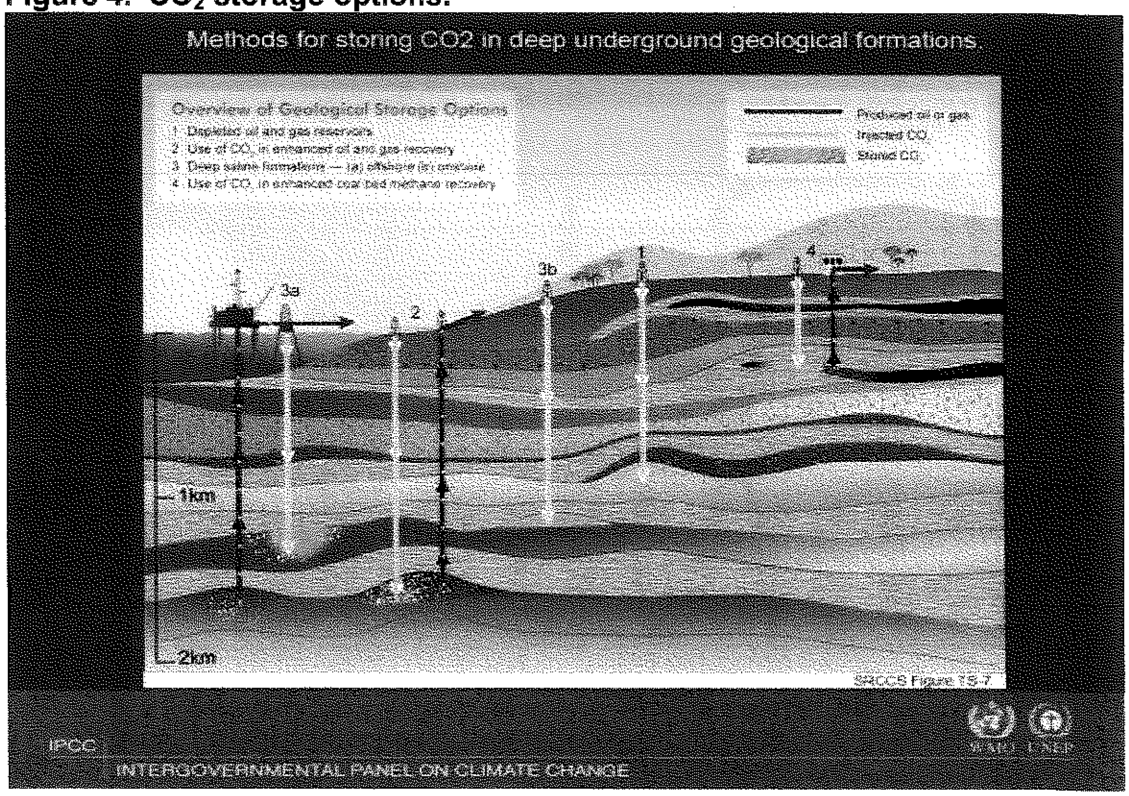

Figure 5. Deep saline formations in the U.S. and Canada. (Formations are depicted in dark blue)

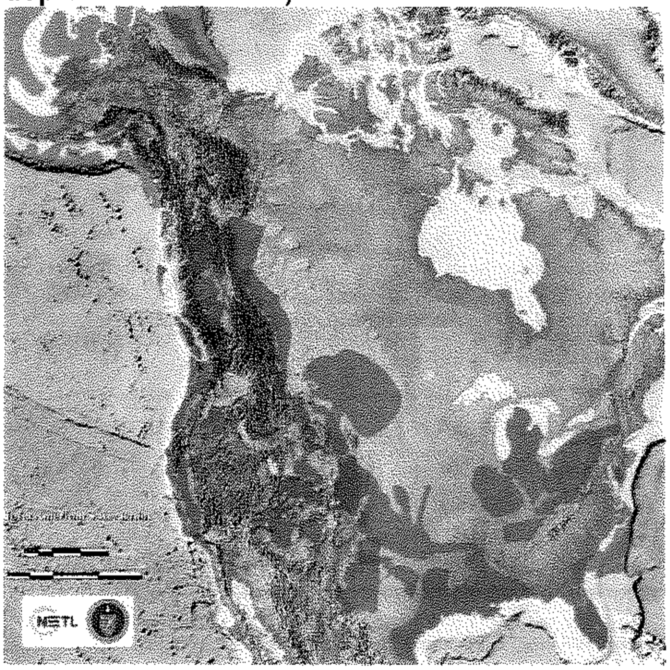

Figure 6. Potential pathways for CO_2 leakage.