FROM EOR TO CCS: THE EVOLVING LEGAL AND REGULATORY FRAMEWORK FOR CARBON CAPTURE AND STORAGE

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Synopsis: Carbon capture and storage has been proposed around the world as a potentially key technology for reducing carbon dioxide (CO_2) emissions. The United States oil and gas industry has a long experience in transporting, injecting, and effectively storing CO_2 in tertiary oil recovery operations usually known as Enhanced Oil Recovery. As a result, there already exists a legal and regulatory framework that addresses many – but not all – of the issues that will need to be addressed if carbon capture and storage is to be adopted by policymakers as part of a carbon regulation regime. A review of that existing framework allows identification of those aspects that appear adequate to govern the sale, transport, and injection of CO_2 for carbon capture and storage purposes as well as those that do not. Building on this analysis, the authors conclude that the current legal framework will be largely adequate from a transactional and interim standpoint to allow parties to structure a relatively seamless transition from CO_2 storage that is an incidental result of oil production operations to those *incremental* injections of CO_2 intended solely for permanent underground storage. The authors also suggest some possible approaches for crafting new rules to fill potentially remaining legal or regulatory gaps.

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I. INTRODUCTION

In recent years, an increasing number of governments around the world have begun to regulate atmospheric emissions of carbon dioxide (CO_2) in one fashion or another. Others, including the United States, are actively debating whether to implement carbon regulation,[1] and if so, under what terms and conditions. One potentially important tool for reducing CO_2 emissions is the separation and "capture" of the CO_2 produced in the generation of electricity from coal; piping it to storage sites where it would be injected for permanent storage in underground geological formations. This process is known as carbon capture and storage or "CCS" (sometimes also referred to as "carbon capture and sequestration" or "carbon capture and disposal").

While interest in CCS is relatively new, the underground injection and effective storage of large quantities of CO_2 is not. As explained below, the United States' oil and gas industry has been transporting CO_2 by pipeline for injection as a tertiary, or enhanced oil recovery (EOR) technique, for nearly forty years.[2] In addition, significant quantities of CO_2 have been piped to industrial facilities for use in various processes as well as for distribution by rail or truck to large numbers of CO_2 end users nationwide. As a result, there is already in place a CO_2 industry infrastructure comprising over approximately 13,000 permitted CO_2 injections wells (over 6,000 of which are active) and thousands of miles of CO_2 pipeline with associated CO_2 handling facilities, all of which represents a major investment of private financial and intellectual capital.

Estimates of the amount of CO_2 injected each year in American EOR activities are in excess of fifty million metric tonnes,[3] with cumulative injections

1. These proposals seek to reduce emission of a number gases that are believed to contribute to changes in the earth's climate (usually termed "greenhouse gases" or "GHG"), not just CO_2. The most important and abundant greenhouse gas by far is water vapor (H_2O), followed by carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), ozone (O_3), and the fluorinated gases (hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6)). PIERS FORSTER, ET AL., INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, THE PHYSICAL SCIENCE BASIS, CHANGES IN ATMOSPHERIC CONSTITUENTS AND IN RADIOACTIVE FORCING (2007) *available at* http://ipcc-wg1.ucar.edu/wg1/Report/AR4WG1_Print_Ch02.pdf [hereinafter IPCC WORKING GROUP I REPORT]. Since human activities have only a small direct influence on the amount of atmospheric water vapor, the focus has been on reducing CO_2 emissions. For an introduction to the regulation of CO_2 and other greenhouse gases other than water vapor under the Kyoto Protocol, the European Union's Emissions Trading System and related matters, John Dernbach & Seema Kakade, *Climate Change Law: An Introduction*, 29 ENERGY L.J. 1 at 9-12 (2008).

2. CO_2 is also used in a few instances in natural gas production (i.e. enhanced gas recovery or "EGR") operations. The use of CO_2 in natural gas production is considerably less mature than use in oil production and has been deployed only at the pilot scale. INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, SPECIAL REPORT ON CARBON DIOXIDE CAPTURE AND STORAGE, (Bert Metz, ed., Cambridge University Press 2005), at 33 (Table TS.5), 216-217, 262, *available at* http://www.ipcc.ch/ipccreports/special-reports.htm [hereinafter IPCC SPECIAL REPORT].

3. IPCC SPECIAL REPORT, *supra note* 2, at 181. The IPCC SPECIAL REPORT appears not to include the second largest CO_2 pipeline system (by capacity) in the United States, which is operated by units of Denbury Resources, Inc.; *Id*. at 183 (Table 4.1 showing existing long-distance CO_2 pipelines in North America and omitting the Denbury projects). By 2008, Denbury was producing and transporting some 700,000 Mcf per day of CO_2, the great majority of which was injected for EOR operations, amounting to an annual rate of over sixteen million metric tonnes. DENBURY RESOURCES, INC., 2007 ANNUAL REPORT 6 (Form 10-K) (2007), http://library.corporate-ir.net/library/72/723/72374/items/285714/AnnualReport2007.pdf; *see also* JAMES P.

since 1972 estimated at over 600 million metric tonnes.[4] The current annual injection quantity is thus roughly equivalent to the amount of CO_2 that might be captured from the first twenty newly constructed 500 MW coal-fired power plants that capture eighty percent of their CO_2 output.[5] This CO_2 is currently being injected through over 6,100 active injection wells[6] and makes possible daily oil production of about 245,000 barrels.[7] While the majority of current CO_2 supply comes from naturally-occurring geologic formations that have been developed much like an oil or gas field, the CO_2-based EOR business originated in the 1970s with anthropogenic sources of CO_2 and even today some CO_2 supply remains anthropogenic in origin, captured by separation from natural gas production or from certain industrial facilities. Moreover, while EOR operations strive to recycle and reuse the maximum amount possible of the initially-injected CO_2, a large percentage of the injected CO_2 – on the order of fifty percent or more[8] – cannot be recovered for reuse under current technology and remains stored in the underground formation as an incident of the oil production operation. This percentage gradually rises over the life of the EOR operation as CO_2 accumulates in the reservoir. The amount of CO_2 that has been incidentally

MEYER, PHD, AM. PETROLEUM INS., SUMMARY OF CARBON DIOXIDE ENHANCED OIL RECOVERY (CO2EOR) INJECTION WELL TECHNOLOGY 2 [hereinafter EOR INJECTION WELL TECHNOLOGY REPORT].

4. EOR INJECTION WELL TECHNOLOGY REPORT, *supra* note 3, at vi.

5. MASS. INST. OF TECH., THE FUTURE OF COAL: OPTIONS FOR A CARBON-CONSTRAINED WORLD 24-39, 105 (2007), http://web.mit.edu/coal/The_Future_of_Coal.pdf [hereinafter THE FUTURE OF COAL]. It has been estimated that an efficient, new 500 megawatt (MW) coal-fired power plant would produce about three million short tons of CO_2 per year. *Id*. If eighty percent were captured on average, twenty such plants would make about forty-eight million tons available for storage per year. As detailed below, however, no such plant has yet been built nor is any under construction.

6. The number of active CO_2 injection wells is published in the *Annual Production Report*, 106 OIL & GAS J. 4 (2008). The total number of CO_2 injection wells that have been permitted since 1972 (which includes CO_2 disposal wells, CO_2 injector wells that have been plugged, and CO_2 injector wells that have been converted from injection to production, etc.) is far larger and has been estimated near 13,000. EOR INJECTION WELL TECHNOLOGY REPORT, *supra* note 3. As of mid-2008, the Texas Railroad Commission reported 9,421 CO_2 permitted injection wells for secondary recovery and another 547 CO_2 injection wells for disposal (which typically dispose of waste streams from gas processing). TEX. R.R. COMM'N, DISTRICTS FOR CURRENTLY PERMITTED CARBON DIOXIDE INJECTION AND DISPOSAL WELLS (2007), http://www.rrc.state.tx.us/divisions/og/uic/fluids.htm; *see generally* Markus G. Puder & John A. Veil, ARGONNE NAT'L LAB., EVALUATION OF STATE AND REGIONAL RESOURCE NEEDS TO MANAGE CARBON SEQUESTRATION THROUGH INJECTION (2007) http://www.gwpc.org/e-library/e-library_documents/e-library_documents_general/Argonne%20Report%20CO2%20Resources.pdf [hereinafter GWPC CO2 Well Survey]. Only a handful of CO_2 injection wells were reported in the GWPC CO_2 Well Survey as "Class V" experimental wells. *Id*.

7. EOR INJECTION WELL TECHNOLOGY REPORT, *supra* note 3, at 2.

8. JANE ELLIS, CEDRIC PHILIBERT & JACEK PODKANSKI, INT'L ENERGY AGENCY, ORG. FOR ECON. CO-OPERATION AND DEV., CARBON CAPTURE AND STORAGE IN THE CDM 15 (Dec. 2007), https://www.iea.org/textbase/papers/2007/CCS_in_CDM.pdf [hereinafter *Philibert, Ellis, & Podkanski*]. More than fifty percent of the injected CO_2 returns with the produced oil in the case of EOR. IPCC SPECIAL REPORT, *supra* note 2, at 215. The IPCC SPECIAL REPORT states that between fifty and sixty-seven percent of CO_2 returns with the produced oil. *Id*. For a review of retention rates from EOR projects in the Permian Basin, *see generally* REID B. GRIGG, N.M. INST. OF MINING AND TECH., FINAL TECHNICAL REPORT: LONG-TERM CO_2 STORAGE USING PETROLEUM INDUSTRY EXPERIENCE (Dec. 30, 2002), http://www.co2captureproject.org/reports/reports.htm#.

stored in this fashion over the last several decades dwarfs the volumes injected by CCS pilot projects around the world.[9]

This physical infrastructure has been built utilizing a less visible *legal and regulatory infrastructure* that currently undergirds the investments and governs the trade, transport, injection, and incidental storage of CO_2 used in oil production operations. Much of this legal structure is due to state legislation that has been adopted specifically for CO_2 operating infrastructure. Commercial disputes have arisen and been resolved; property law questions have been examined; regulatory permits governing CO_2 injection wells have been in place for years; and the regulatory status of CO_2 pipelines under existing statutes was resolved decades ago.

Hence, just as Molière's famous fictional "bourgeois gentilhomme" was astonished to discover that he had been speaking prose for forty years without knowing it,[10] so climate change policy makers are discovering that the United States' oil industry has been engaged in CCS for nearly forty years without knowing it under the name of CO_2-based EOR. If CCS is adopted as a CO_2 emissions compliance technique under a carbon regulation regime, much of the existing physical infrastructure is likely to be further adapted over time to receive anthropogenic CO_2 that is intended for permanent storage. Similarly, but again perhaps less obviously, much of the existing legal and regulatory framework, both federal and state, will also continue to govern such activity. In sum, legislators and regulators who are presently seeking to craft a framework for CCS are not writing on a blank slate. Rather they will be amending a decades-old *acquis*[11] of state and federal statutes, judicial precedent, regulatory rules, and commercial practices.

Because the existing legal and regulatory framework for CO_2-based EOR operations is not widely known outside the applicable state arenas and the oil

9. For example, in 2005, the IPCC SPECIAL REPORT that combined injections at the largest CCS pilot sites amounted to just three million tonnes per year, with all remaining projects accounting for perhaps one-tenth as much, amounting to about six percent of the annual EOR-based injections. This is not to minimize the value of the experimental projects, which are focused largely on testing CO_2 movement in non-oil and gas formation, principally deep saline aquifer formations. As discussed below, these formations will be required if CCS is mandated for coal-fired power plants. IPCC SPECIAL REPORT, *supra* note 2, at 31-33, 201 tbl. 5.1

10. Molière, *Le Bourgeois Gentilhomme*, Act. II, sc.4 ("*il y a plus de quarante ans que je dis de la prose, sans que j'en susse rien*") ("I've been speaking prose for more than forty years without knowing anything about it"), http://www.theatre-moliere.com/index_.php?selecto=oeuvres&selecta=act&ido=36&acueil=ok (French original) (English translation by the author).

11. The analogy here is to the concept of the "*acquis communautaire*" or "*EU acquis*" which is a technical term in European Union law referring to the entire body of legislation of the European Communities and Union that has been accumulated up to a given point in time. For a useful introduction into the concept and its role in European Union law, Dr. Aaron Beers Sampson & Dr. Stephen J. Silvia, *Acquis Communautaire and European Exceptionalism: A Genealogy* (Am. Consortium on European Union Studies, Working Paper No. 2003.1) *available at* http://www.american.edu/aces/Working%20Papers/2003.1.pdf. We note also that an international "CCS Regulators Network" was established in 2008 by the International Energy Agency in Paris (http://www.iea.org/Textbase/subjectqueries/ccs_network.asp) in association with, *inter alia*, Carbon Sequestration Leadership Forum (http://www.cslforum.org/) and University College London's Carbon Capture Legal Programme (http://www.ucl.ac.uk/cclp/index.php). The CCS Regulators Network is building a potentially key information exchange platform for CCS legal and regulatory matters that may conceivably evolve towards a policy-coordination platform in future years.

and gas industry, policy makers may wish to become more familiar with the current structure so that they may make more informed judgments regarding which aspects of the current law may be incorporated without change into a more expansive legal regime intended to govern CO_2 trade, transport and injections for CCS and which aspects may require some modification. This analytic effort will allow policy makers to better identify any existing legal or regulatory gaps, for which new legislation or regulation may be needed, either by adapting other existing law or crafting new law.

The purpose of this article is to facilitate these tasks. We begin by reviewing the current industry that transports, injects, and stores CO_2 for EOR purposes and seek to identify some important similarities and differences with a potential "CCS industry" that may (or may not) come into existence in future years. We then review the existing legal and regulatory framework that governs each step of the existing EOR-based use of CO_2. We conclude by considering how well the existing framework may accommodate a transition from the existing EOR-focused industry that stores CO_2 as part of the production process to one that includes increasing numbers of CCS-focused transactions, and the changes that may be required to prepare for such a transition.

II. BACK TO THE FUTURE: FROM INCIDENTAL STORAGE OF CO_2 FOR EOR TO POTENTIAL INCREMENTAL STORAGE FOR CCS

A. The role of CO_2 in EOR and the incidental storage of CO_2.

CO_2 has been widely used as an industrial gas in various sectors for many years.[12] Under normal atmospheric temperature and pressure, it is a gas. When sufficiently compressed however it reaches a point where it can move across the physical boundaries separating more commonly known gas and liquid phases and become a "dense phase gas" or a "supercritical fluid." In this state, the substance exhibits certain characteristics of both a gas and a liquid. For example, it is able to diffuse into and through solids like a gas, but remains capable of dissolving certain materials, as does a liquid.[13] In addition, dense-

12. Uses include the manufacture of urea, methanol, and polyurethanes; pharmaceuticals; the preparation of food and beverages (carbonation of beverages, packaging, and chilling or freezing); and health care (including use for insufflation during medical procedures). It is further used in the manufacture of metals, pulp and paper, and electronics as well as in waste treatment (to help control the pH of liquid effluents) among other applications. For more detail on industrial applications of CO_2, *see generally* IPCC SPECIAL REPORT, *supra* note 2, at 332, 393.

13. For an excellent (and not overly-technical) review of supercritical fluids, *see e.g.*, JOHN MCHARDY & S.P. SAWAN, SUPERCRITICAL FLUID CLEANING: FUNDAMENTALS, TECHNOLOGY AND APPLICATIONS 1 (John McHardy, Samuel Sawam eds., Noyes Publications 1998) (1998). The supercritical state, sometimes referred to as a fourth state of matter to complement the traditional solid, liquid and gas states, was discovered in 1869 and the phenomenon of supercritical fluid solubility identified in the following decade. *Id*. at 1. The authors describe the supercritical state as follows:

> A substance is said to be in the gaseous state when heated to temperatures beyond its critical point. However, the physical properties of a substance near the critical point are intermediate between those of normal gases and liquids, and it is appropriate to consider such supercritical fluid as a fourth state of matter. For applications such as cleaning, extraction and chromatographic purposes, supercritical fluid often has more desirable transport properties than a liquid and orders of magnitude better solvent properties than a gas. *Id*. at 2.

phase CO_2 is (as the name implies) far denser than CO_2 at atmospheric temperature and pressure (as much as 100 times the density of gaseous natural gas) and is therefore more economical to ship by pipeline.[14]

The particular physical qualities of CO_2 in this state allow it to approach, or enter, a miscible state with the oil that remains trapped in pore spaces of a production reservoir, causing the oil droplets to expand, become detached from the adjoining rock, and join the CO_2 in diffusing through the pore space. In this manner the oil is effectively carried along with the CO_2 to a production well bore where it is brought to the surface, separated from the CO_2, and sold. The CO_2 may then be re-compressed and returned to a pipeline for re-injection into the reservoir. Under present techniques (and depending on the formations into which it is injected) approximately half of the CO_2 injected for EOR purposes can be recycled for further use while the remainder stays in the formation and is effectively stored indefinitely as a natural result of the enhanced oil production operations.[15]

This storage of CO_2 is thus *incidental* to the production of oil during EOR operations. It is physically indistinguishable from the *incremental* storage of CO_2 that would occur if the depleted oil formation were to be later used for storing CO_2 captured from a power plant, other industrial source, or even naturally-occurring CO_2. In all such cases the CO_2 would be injected through the same well bore into the same formation and at pressures (and depths) that ensure that it remains in the supercritical state. In all cases, the injection well would under existing rules be plugged and abandoned under identical industry and regulatory standards (addressed in Section III.D).

While physically indistinguishable from storage that already occurs during EOR operations, the incremental storage of CO_2, in excess of what is required for the production of oil, would have important legal and regulatory implications because the existing regulatory authorizations apply only to CO_2 injections in conjunction with oil and gas production.

In addition to the CO_2 that remains incidentally stored in the formation at the economic termination of EOR operations, there also remains a substantial percentage of the Original Oil in Place (OOIP) that is unrecoverable under current techniques. The amount of oil remaining will vary, but is generally on

14. INTERNATIONAL ENERGY AGENCY, PROSPECTS FOR CARBON DIOXIDE CAPTURE AND STORAGE 79 (2004), http://www.iea.org/textbase/nppdf/free/2004/prospects.pdf (estimating transport of supercritical CO_2 as high as ten to 100 fold higher density than natural gas or hydrogen, resulting in lower per-unit of weight transport costs as compared to natural gas). The conversion factor typically used to convert a volume of a thousand cubic feet of CO_2 into US "short tons" is approximately 17.25 at atmospheric temperature (sixty degrees) and pressure. BRANDON NUTTALL, KY. GEOLOGICAL SURVEY, ANALYSIS OF DEVONIAN BLACK SHALES IN KENTUCKY FOR POTENTIAL CARBON DIOXIDE SEQUESTRATION AND ENHANCED NATURAL GAS PRODUCTION 14 (2005), http://www.osti.gov/energycitations/servlets/purl/821856-OeJYtg/native/821856.pdf. A short ton weighs .907185 as much as a metric tonne of 1,000 kilograms. Accordingly the conversion factor for converting one Mcf of CO_2 to metric tonnes (the usual unit of measure in international documents) is approximately 15.525.

15. *Philibert, Ellis* & *Podkanski, supra* note 8. As noted above, over time the percentage of recycled CO_2 that remains in the reservoir increases such that the amount of CO_2 retained in the reservoir gradually rises.

the order of one-third or more of the OOIP.[16] This is a hydrocarbon resource that is presently unrecoverable under existing technology, but which may well become recoverable in the future, as it has been fairly common practice in the oil and gas industry to re-enter oil fields that were plugged out decades before and begin producing oil again under new development plans and techniques. This is a key fact that is often overlooked in classifying a reservoir as depleted and in discussions of "who owns the pore space" to be used for CO_2 storage.

This fact has very important legal implications regarding subsurface rights and which are discussed in more detail in Section III.E. In brief, it simply means that, following termination of CO_2 injections for EOR purposes, there remains a mineral – oil – that is owned by the mineral interest owner, that continues to occupy pore space in the formation, and that may yet be reduced to future possession by the owner of the mineral interest or his lessee. In addition, it is possible that CO_2 that has been purchased and injected for EOR purposes, and incidentally stored following termination of EOR operations, in one reservoir could become a valuable commodity once again at some future time if it is produced, transported, and re-injected in another reservoir for additional EOR projects. Given the long life cycle of EOR projects in which CO_2 injections may continue for decades, there may be multiple opportunities for some portion of the CO_2 injected in one field to be recycled for use in other fields without ever being released into the atmosphere. Practitioners will want to protect property rights to the stored CO_2, the storage pore space, as well as the ownership interests in any remaining hydrocarbons. Similarly, any set of rules governing incentive payments for removing CO_2 from the atmosphere by geologic storage will also need to take into account these complex dynamics of existing and potential future usage of the stored CO_2.

B. Origins and growth of CO_2-based oil production.

The commercial use of CO_2 in the production of oil dates at least from 1972 in the SACROC unit in the Permian Basin of West Texas.[17] Initially, anthropogenic sources of CO_2 were used, obtained by separating CO_2 from the production of natural gas which was transported in a supercritical state via a sixteen-inch diameter pipeline. The line was relatively small, designed to carry about seventy million cubic feet of CO_2 per day. Over fifty-five million tons of CO_2 had been injected in the SACROC unit by 2006.[18] Following initial operations at the SACROC unit, efforts were made to locate additional large CO_2 sources, and by the late 1970s, several major discoveries were made of high quality CO_2-bearing geological formations, principally including McElmo Dome (Southwestern Colorado), Bravo Dome (Northeastern New Mexico), and Sheep Mountain (South Colorado). With these primary sources of CO_2 secured, the

16. Advance Notice of Proposed Rulemaking, *Enhanced Oil and Natural Gas Production through Carbon Dioxide Injection*, 71 Fed. Reg. 11557, 11558 (2006).

17. "SACROC" is an acronym standing for the "Scurry Area Canyon Reef Operators Committee." The production unit is located in Scurry County, Texas and managed by a committee of the oil and gas operators. Han, McPherson, and Wang, CO2 Sequestration in the Permian Basin SACROC Northern Platform, Site of 35 Years of CO_2 Injection, Presentation at American Geophysical Union (2006) (abstract available at http://adsabs.harvard.edu/abs/2006AGUFM.H21A1356H).

18. *Id*.

major oil companies began building a network of CO_2 pipelines to move the gas south-by-east to supply various fields in West Texas and Eastern New Mexico, beginning with the Cortez pipeline running from the McElmo Dome diagonally southeast across New Mexico to the Permian Basin.[19]

Additional sources of anthropogenic CO_2 have been developed to supply other western EOR operations. The largest of these is near Labarge, Wyoming where a unit of Exxon Corporation began capturing large quantities of CO_2 from natural gas processing facilities, and making it available for transportation to EOR injection sites. Cumulative injections of anthropogenic CO_2 captured from the gas processing facilities there have totaled more than twenty million tons.[20]

In the 1980s, CO_2 production and pipeline operations moved east of the Mississippi River following the development of the Jackson Dome CO_2 field in central Mississippi and the construction of the CO_2 pipeline required to supply target EOR injection projects elsewhere in the state.[21] At year end 2007, proved reserves of CO_2 at the Jackson Dome site had increased to approximately 5.6 Tcf and daily volumes were on the order of 700,000 per day, amounting to more than sixteen million metric tonnes per year.[22]

A map showing the location and scale of the nation's CO_2 pipelines as of mid-2008 is displayed in Figure 1.[23]

19. As noted in Section III.C.2a., prior to construction, the project developers sought jurisdictional determinations of the CO_2 pipeline's regulatory status under the Interstate Commerce Act and the Natural Gas Act. The regulatory rulings determining that the CO_2 pipeline was not subject to jurisdiction under those statutes are discussed there. Today, the largest EOR operator in the Permian Basin (and the United States) is Occidental Petroleum Corporation.

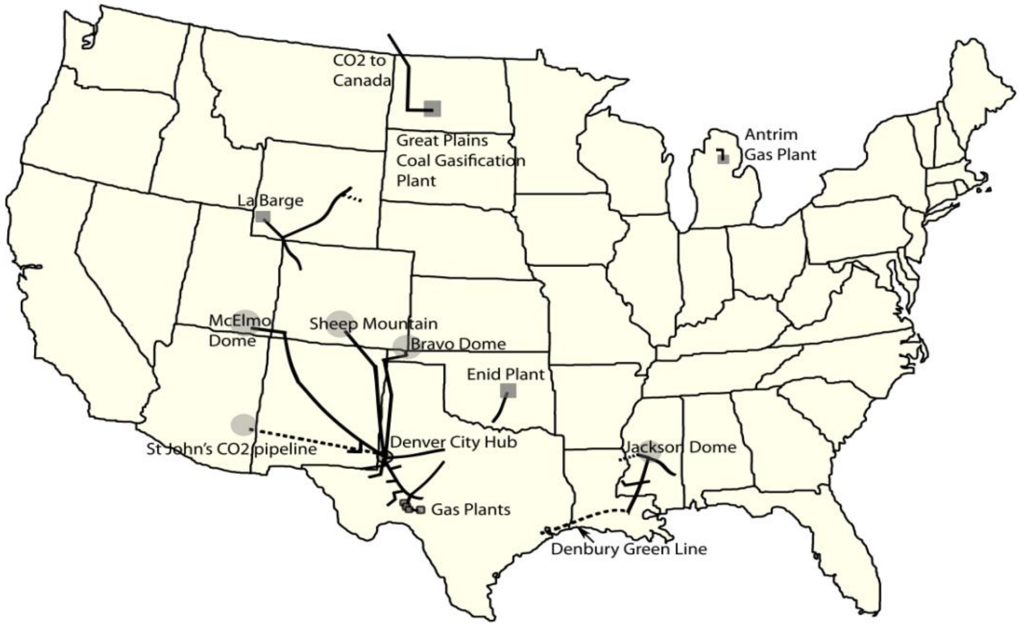
20. IPCC SPECIAL REPORT, *supra* note 2, at 216 (Box 5.6). Annual injections at that time were around 3 million tonnes. *Id*. The principal EOR operator in Wyoming is Anadarko Petroleum Corporation.

21. Shell W. E & P, Inc. v. Bd. of Supervisors of Pike County, 624 So.2d 68, 71 (Miss. 1993). The initial pilot CO_2 flood was begun in 1973 with small volumes of CO_2 delivered by truck.

22. DENBURY RESOURCES, *supra* note 3 (volumes converted to metric tonnes using conversion factor of 15.525). A portion of this CO_2 stream serves industrial users.

23. For a presentation showing the historical development of CO_2 pipelines in the Permian Basin since 1970, *see e.g.* KINDER MORGAN CO_2 COMPANY, LP, PERMIAN BASIN OVERVIEW (July 25, 2006), http://www.wyopipeline.com/information/presentations/2006/July/WPA%20Presentation%20060725.ppt.

FIGURE I



Map of CO2 pipelines (2008)

As oil prices fell with the removal of price controls on oil and the rationalization of the natural gas markets during the 1980s,[24] interest in developing new CO_2-based EOR operations waned and no new major projects were developed for many years. With the increase in energy prices after the turn of the century, however, interest in EOR revived. The oil industry's CO_2 pipeline network has been expanded both by new construction,[25] as well as by conversion to CO_2 transportation of pre-existing natural gas pipeline.[26] The maps or descriptions of pipeline infrastructure in some major reports have thus

24. Robert J. Michaels, *The New Age of Natural Gas: How the Regulators Brought Competition*, REGULATION: THE CATO REV. OF BUS. & GOV'T, winter 1993, at 16; *see also* Associated Gas Dist. v. F.E.R.C., 824 F.2d 981 (D.C. Cir. 1987).

25. A 325 km pipeline was placed in service in 2000 running north from coal gasification plant in North Dakota to Weyburn EOR project site in Saskatchewan, Canada, IPCC SPECIAL REPORT, *supra* note 2 at 204; 125-mile CO_2 pipeline in Wyoming in 2003-2004, Press Release, Anadarko Petroleum, "Anadarko Announces Fourth-Quarter and 2003 Financial and Operating Results" (Aug. 30, 2004); and new CO_2 pipeline construction in eastern Mississippi in 2006 and northwestern Mississippi in 2008, DENBURY RESOURCES, *supra* note 3.

26. *See, e.g.*, *Southern Natural Gas Co.*, 115 F.E.R.C. ¶ 62,266 at P 1-3 (2006) (order approving abandonment by sale of 142 miles of natural gas pipeline (principally eight and eighteen-inches in diameter) in Western Mississippi for conversion to CO_2 transportation). As discussed more fully below, the Federal Energy Regulatory Commission, (FERC), order reiterated the non-jurisdictional nature of pipeline transmission of CO_2, noting that such pipeline transportation is "an activity not subject to NGA or the jurisdiction of the Commission." *Id.* at P 3.

become outdated.[27] Major planned expansions of the EOR pipeline network have been announced.[28]

In addition, beginning in 2006 several large transactions have been announced for the capture of CO_2 from new non-power plant industrial sources, with the CO_2 to be used for expanding EOR operations. These transactions involved proposed new facilities to convert coal or petroleum coke into liquid substitute for petroleum products (generally referred to as "Coal to Liquids" or "CTL" facilities) or to manufacture ammonia.[29] These are industries for which the cost of CO_2 capture is generally thought to be considerably lower than the cost for a coal-fired power plant. If all of these facilities are constructed, the total quantity of CO_2 that would be captured and stored as part of EOR operations (instead of vented to the atmosphere) would be very considerable and could, thus, represent a solid beginning of a potential transition towards incorporating CO_2 captured from industrial facilities into the existing EOR infrastructure.

C. The core elements: capture; treating; compression and transport; injection and storage; and verification and monitoring.

This is the existing industry that – under a system of carbon regulation – would begin to accommodate injections of CO_2 that is captured from coal-fired power plants. Initially, the anthropogenic CO_2 may serve to supplement the existing supplies of CO_2 produced from naturally-occurring underground reserves and captured from non-power plant industrial sources (natural gas processing, ammonia production, etc.). Assuming that carbon regulation were sustained over the next several decades, the supplies of power plant-sourced CO_2 would eventually exceed the needs of the oil and gas producing industry and begin to be injected solely for the purpose of long-term underground storage. Hence, in order to evaluate the adequacy of the current legal and regulatory regime for CO_2 transactions, transport, and storage, it will be helpful to provide a brief overview of the core elements of a carbon capture and storage industry and

27. IPCC SPECIAL REPORT, *supra* note 2 at 182-184, tbl. 4.1 (omitting mention of second largest CO_2 pipeline system and showing only portions of current pipeline infrastructure on map).

28. Sempra Energy, Carbon Capture and Storage: EOR in the Rockies, Presentation to the Wyo. Pipeline Auth. (May 15, 2007) (discussing CO_2 pipeline linking existing pipeline systems in Wyoming and North Dakota); DENBURY RESOURCES, INC., THE GREEN PIPELINE PROJECT (June 30, 2007), http://www.denbury.com/Green%20Pipeline%20Project%20Brochure.pdf (describing major new CO_2 pipeline proposed to Texas oil field).

29. *See e.g.* Press Release, Denbury Resources, Inc., Denbury Signs Agreement to Purchase Additional Manufactured CO_2 (June 25, 2007), http://www.secinfo.com/dsvrp.uDX3.d.htm; Press Release, Denbury Resources, Inc., Denbury Resources Inc. Acquires Option to Purchase another Tertiary Flood Candidate; Agreement to Purchase Manufactured Source of CO_2 (Nov. 8, 2006); DKRW ADVANCED FUELS, LLC, MEDICINE BOW FUEL & POWER, LLC, FACT SHEET, http://www.futurecoalfuels.org/documents/011207_dkrw_fact_sheet.pdf (last visited Sept. 18, 2008) (coal-to-liquids plant planned near Medicine Bow, Wyoming). In addition, an application has been filed for an IGCC plant with carbon capture and EOR-based storage in California. Application for Certification of Hydrogen Energy International, LLC, Cal. Energy Comm'n, Docket No. 08-AFC-8 (July 31, 2008) (proposed IGCC plant to gasify petroleum coke (or blends of petroleum coke and coal, as needed) to produce hydrogen-rich synthesis gas for power generation while capturing approximately 130,000 Mcf/d of CO_2 to be transported less than three miles for use in EOR and sequestration (storage)).

begin to identify similarities and differences with the current EOR-based CO_2 business. The purpose of this overview is not to provide a treatise of CCS (for which the reader is directed to the references in the notes),[30] but merely to lay the basis for evaluating potential homologues in the EOR world for which an existing legal framework is largely in place.

1. Capture.

In oversimplified terms, the CCS process will consist in capturing the carbon content of coal (whether before, during, or immediately following combustion), removing impurities such as water, nitrogen, hydrogen sulfide, and mercury (among others) and then combining the carbon with oxygen to create CO_2 for removal from the premises by pipeline. While carbon dioxide has been captured on a commercial scale for several decades by separating CO_2 from natural gas production or during certain industrial processes, the current focus has shifted to the possibility of capturing carbon dioxide from coal-fired electricity generating facilities. This change of focus is due of course to the large role played by coal-fired power plants in overall CO_2 emissions. Coal is recognized as the single largest contributing fuel source to global CO_2 emissions, accounting for roughly forty percent of all such emissions, perhaps seventy percent of which are attributable to coal-fired electricity generation.[31]

Proponents of CCS believe that it will be an enabling technology that may eventually be employed on a vast scale to allow the United States and other coal-based economies to make significant reductions in CO_2 emissions even while continuing to burn large quantities of coal. In this view, CCS would serve as a transitional, or "bridge" technology, between coal-based power generation to newer energy supply and consumption technologies (including building and urban designs) that reduce CO_2 emissions or avoid the need for fossil fuel combustion in the first place.[32] Because capturing CO_2 from power plants is expected to be costly, however, it is expected that some incentive or subsidy will

30. There are many good overviews of the CCS process designed for by policy makers or the broader public. *See e.g.* IPCC SPECIAL REPORT, *supra* note 2 (Summary for Policy Makers). Books devoted entirely to CCS include CARBON CAPTURE AND ITS STORAGE (Shackley & Gough, eds., Ashgate Publishing 2006) (2006) (with a strong focus on CCS in the United Kingdom) and CARBON CAPTURE AND SEQUESTRATION: INTEGRATING TECHNOLOGY, MONITORING AND REGULATION (Wilson & Gerard eds., Blackwell 2007) (2007). In principle, carbon may be captured before, during, or following combustion. THE FUTURE OF COAL, *supra* note 5, at 24-39. One of the principal capture technologies being discussed is the use of an Integrated Gasification Combined Cycle (IGCC) generating unit. *Id*. In this process, coal is gasified and the carbon and impurities removed from the gas stream, leaving a hydrogen-rich gas that is then burned in a combined cycle unit much the same as natural gas (albeit at a higher temperature and with certain other operational differences that will require design changes from current natural gas based technology). *Id*.

31. THE FUTURE OF COAL, *supra* note 5, at 1.

32. NATURAL RES. DEF. COUNCIL, NRDC ISSUE PAPER, COAL IN A CHANGING CLIMATE 14 (2007). *See also* Testimony of David G. Hawkins, Dir., Climate Center, Nat. Res. Def. Council, Before the Subcommittee on Energy and Air Quality of the House Committee on Energy and Commerce Hearing on Carbon Capture and Sequestration 20 (Mar. 6, 2007) (stating that "it is imperative that we to act now to deploy [CCS] systems"). Mr. Hawkins uses the term "carbon capture and disposal" in place of CCS. Opponents of CCS, on the other hand, stress uncertainties, costs, and risks of a new technology or argue that CCS simply postpones what opponents view as the inevitable day when coal combustion must be reduced. *See e.g.* GREENPEACE INT'L, FALSE HOPE: WHY CARBON CAPTURE AND STORAGE WON'T SAVE THE CLIMATE (May 2008), http://www.greenpeace.org/international/press/reports/false-hope.

be required, at least in the initial phases of implementation (which may last a decade or more). This view is embodied in a number of governmental initiatives in various stages of review or adoption around the world.[33] These include actions by the European Union (EU),[34] the Clean Development Mechanism under the rubric of the Kyoto-based Intergovernmental Panel on Climate Change (IPCC),[35] and various legislative proposals or action by United States state legislatures[36] and by the United States Congress.[37]

The question of how much it may cost to capture significant portions of CO_2 from a coal-fired power plant (whether for a new or a retrofitted facility) is beyond the scope of this article. The reader should be aware that there is considerable uncertainty and that the range of cost estimates in the current literature is very wide.[38] For purposes of this article, we simply assume that the cost hurdles may somehow be overcome and that CO_2 will at some point in the next decade begin to be captured at some newly-constructed power plants and made available for transport and storage (while recognizing that widespread

33. A map-based portal to much of the CCS-related information cited in this article (including an updated map of carbon dioxide pipeline infrastructure) may be found at: http://www.marstonlaw.com/ (last visited Sept. 20, 2008).

34. *Commission Proposal for a Directive of the European Parliament and of the Council on the Geological Storage of Carbon Dioxide and Amending Council Directives 85/337/EEC, 96/61/EC, Directives 2000/60/EC, 2001/80/EC, 2004/35/EC, 2006/12/EC and Regulation (EC) No 1013/2006*, COM (2008) 30 final (Jan. 23, 2008) [hereinafter PROPOSED EU CCS DIRECTIVE].

35. The entry portal to the Clean Development Mechanism (CDM) is found at: http://cdm.unfccc.int/index.html (last visited Sept. 18, 2008). The CDM has not yet approved CCS as a qualifying methodology. CCS remains under review and the question is due to be reviewed by the Executive Board at a meeting in late 2008. For a detailed review of the CDM's developing policy toward CCS through year end 2007, *Philibert, Ellis,* & *Podkanski*, *supra* note 8.

36. States adopting CCS-related legislation in recent years include Wyoming (adopting HB 89 on property rights and HB90, addressing injection and storage issues), Illinois (adopted legislation addressing long-term liability issues) and Kansas (statute requiring state regulatory commission to establish rules and regulations for geologic storage and providing certain tax incentives for related equipment). For a review of state initiatives as of early 2008, *see, e.g.*, Darrick W. Eugene, *State CCS Progress Well in Front of Federal Natural Gas and Electricity* 24 NATURAL GAS & ELECTRICITY 8 (May 2008) [hereinafter *State CCS Progress*].

37. A notable exception is the carbon regulation regime being implemented beginning January 1, 2009, by a number of states in the northeast United States (the Northeast Regional Greenhouse Gas Initiative or "RGGI"). The RGGI rules do not include CCS among the qualifying offset techniques. The question of whether CCS may eventually be included, however, may be revisited at some future date. The RGGI's website is found at http://www.rggi.org.

38. In early 2007, the MIT study suggested that based on 2005 cost data, an emissions price of around 30 dollars per metric tonne would begin to make CCS cost competitive with non-CCS generation options. THE FUTURE OF COAL, *supra* note 5, at xi, 24-40. But later in 2007, one of the principal authors provided a range based on 2005 cost data of thirty to forty-five dollars per metric tonne and stated that costs by late 2007 were "at least" fifty percent higher. Howard Herzog, The Economics of CO_2 Capture and Storage 9, Presented at the Second Int'l Symposium Capture and Geological Storage of CO_2, Paris (Oct. 5, 2007), http://www.colloqueco2.com/presentations2007/ColloqueCO2-2007_Session4_5-Herzog.pdf. That revision would suggest a cost range of around forty-five to sixty dollars per metric tonne. Other estimates have been published. *See*, *e.g.*, INTERNATIONAL ENERGY AGENCY & THE ORG. FOR ECON. CO-OPERATION & DEV. (OECD), PROSPECTS FOR CO_2 CAPTURE AND STORAGE 17-18 (2004), http://www.iea.org/textbase/nppdf/free/2004/prospects.pdf (twenty-five to fifty dollars per metric tonne at present, falling to a range of twenty-five to thirty dollars by 2030), and IPCC SPECIAL REPORT, *supra* note 2, at 10-11 (fifteen to seventy-five dollars: and noting that cost estimates "vary widely").

deployment of the carbon capture technology in power generation may in fact take several decades).[39]

2. Treating

Following capture, most gas likely will need to be treated to produce a product that is suitable for transport and injection. The chemical composition of CO_2 produced by a coal-fired power plant will tend to vary with many factors, including the capture technology used and the composition of the specific coal consumed (to name just a few factors). The CO_2 produced from an Integrated Gasification Combined Cycle (IGCC) plant (which should operate more efficiently than a capture-retrofitted conventional plant) is expected to have a very different composition than CO_2 captured from a retrofitted conventional power plant.[40] It has been estimated in fact that an IGCC plant will generally produce much higher-quality CO_2 with a sharp reduction in the concentration of minor and trace contaminant elements as compared to retrofitting a conventional coal-fired plant.[41] Mercury (Hg), however, has been identified as a potential exception to this general rule.[42]

Indeed, some commentators have even suggested that certain contaminants might be *added* to the CO_2 stream destined for geological storage as a preferred means of disposing of toxic substances that would otherwise be stored in solid form above ground.[43] We note here only that the deliberate introduction of contaminants into a CO_2 stream would most likely make the stream unsuitable for EOR purposes (and unsuitable for commingling with any CO_2 pipeline system serving EOR projects) and therefore could limit the ability to offset CCS costs by using the gas for EOR purposes. Of course, the inclusion of any toxic material in a CO_2 stream intended for underground injection could raise

39. There is considerable uncertainty as to timing for actual deployment of carbon capture technology in electricity production. In 2007, a number of proposals to construct IGCC plants were withdrawn or cancelled. Rebecca Smith, *Coal's Doubters Block New Wave of Power Plants*, WALL ST. J., July 25, 2007, at p.1. In addition, state regulators have denied some proposals to construct IGCC plants that would have had at least the potential to capture CO_2, citing uncertainties about the technology, the regulatory framework for CO_2 emissions, and costs. *See, e.g.*, *Appalachian Power Company*, PUE-2007-00068 (Apr. 14, 2008) (Final Order rejecting proposal to build 629 MW IGCC plant in West Virginia for lack of adequate showing of reasonableness or prudence). However, at least one project to build an IGCC power plant with at least the potential to add carbon capture capability is presently moving forward. *Joint Petition* & *Application of Duke Energy Indiana, Inc.* et al., Ind. Utilities Reg. Comm'n, Cause No. 43114 (Nov. 20, 2007) (order issuing certificates of public convenience and necessity subject to various conditions for Edwardsport, Indiana IGCC Project).

40. JOHN A. APPS, ERNEST ORLANDO LAWRENCE BERKELEY NATIONAL LABORATORY, A REVIEW OF HAZARDOUS CHEMICAL SPECIES ASSOCIATED WITH CO2 CAPTURE FROM COAL-FIRED POWER PLANTS AND THEIR POTENTIAL FATE DURING CO_2 GEOLOGIC STORAGE 15, 37-40 tbls. 4, 10 (Mar. 2006) http://www.osti.gov/energycitations/servlets/purl/888971-pR0JMK/888971.PDF [hereinafter APPS]. *See also* THE FUTURE OF COAL, *supra* note 5, at 34-39.

41. APPS, *supra* note 40. The paper's author stresses that the assessment of the likely disposition of various elements in coal consumed in an IGCC plant are "tentative." *Id.* at 41. While the conclusions are tentative, the paper nevertheless stands out in its effort to trace the combustion and storage fate of each of the various hazardous substances likely to be produced at an IGCC plant.

42. *Id.* at 50-51, *see also* THE FUTURE OF COAL, *supra* note 5, at 37 (ICGG may be designed to achieve more than ninety-five percent Hg removal with small cost increases).

43. APPS, *supra* note 40, at 44-47.

additional questions regarding future liability of the parties. Some of these issues are raised in a rulemaking proceeding commenced by the United States Environmental Protection Agency (EPA) that is addressed in Section III.D.

The interaction of a given CO_2 stream with a particular geological formation may differ based on the possible combinations of minerals or chemicals in the CO_2 stream and in the target formation. As a result, certain sites may be suitable for some CO_2 streams, but not for others. This implies that the quality standards for "storage quality" CO_2 may not be generally applicable, but may need to be particularized for individual storage sites.[44]

In sum, the CO_2 stream captured at a given power plant will not be 100 percent carbon dioxide, but will include various other substances. As a result, contractual quality standards will have to be developed to protect the interests of all participants in a CCS transaction and ensure that the CO_2 stream is suitable for the downstream facilities and its intended uses. Any regulatory standard that may be developed will need to be sufficiently flexible to take into account differences in the chemical composition of the output source, whether or not the gas will be injected for EOR or other long-term storage. Pipeline and storage operators will of course need to set their own quality standards that are tailored to existing facilities and intended use.[45]

3. Compression and Transportation

The next step is to transport the treated CO_2 stream to an injection site. While relatively small quantities of CO_2 may be transported by tanker truck or barge, the very large quantities required for EOR operations – and the still greater quantities contemplated in a national CCS regime – will be transported by pipeline.[46] For pipeline transportation, the CO_2 gas stream will be compressed to a dense phase at around 2,000 psi. Compressing the gas for transportation requires considerable energy. Since CO_2 is a non-hydrocarbon and cannot be burned, the compression step for CO_2 transportation is unlike that for natural gas pipelines where the fuel can be drawn from natural gas being transported. Accordingly, compressor stations for CO_2 pipelines are either electrically powered or natural gas-fired if natural gas is available at a given compressor site.

44. The presence of hydrogen sulfide (H_2S) further illustrates some of the gas quality and treatment issues that may arise. In an IGCC plant, this gas would be the primary gaseous sulfur compound resulting from gasification of the coal. APPS, *supra* note 40, at 36, 45. Actual field experience, however, has also shown that even small amounts of H_2S in the CO_2 injection stream lead to far higher concentrations of H_2S accumulating in the surface EOR production equipment tank batteries when the CO_2 is recycled. Personal communication from Tracy Evans, Senior Vice President, Reservoir Engineering, Denbury Resources, Inc. (notes on file with author). This experience will lead EOR project operators in most cases to severely limit the allowed tolerance for H2S in the initial source CO_2 stream.

45. The quality specifications for the Canyon Reef pipeline are reproduced in the IPCC SPECIAL REPORT, *supra* note 2, at 182 box 4.1.

46. INTERNATIONAL ENERGY AGENCY, PROSPECTS FOR CO_2 CAPTURE AND STORAGE 79 (2004), http://www.iea.org/textbase/nppdf/free/2004/prospects.pdf (estimating transport of supercritical CO_2 as high as ten to 100 fold higher density than natural gas or hydrogen, resulting in lower per-unit of weight transport costs as compared to natural gas). While CO_2 could in principle also be liquefied similarly to natural gas and transported via ship, the legal and regulatory framework for such shipments is beyond the scope of this article.

The size and configuration of the pipeline system that would ultimately be required to support full implementation of CCS in the United States is extremely unclear at present. It depends first and foremost on the geologic formations chosen for CO_2 storage and the location of the initial power plants or other CO_2 supply sources at which capture equipment might be installed. In addition, the configuration of the system is likely to depend in significant part on the extent to which the existing CO_2 pipeline infrastructure for enhanced oil recovery projects is able to be used to serve for CCS purposes. System configuration could also depend on the extent to which existing natural gas pipelines may be converted to CO_2 transportation, a pipeline option which has already been used successfully for EOR purposes.[47] The suitability and location of particular formations for CO_2 storage may also have major consequences for the potential scale and cost of a CO_2 pipeline network.[48] The fact that the existing CO_2 pipeline infrastructure is also dedicated to EOR purposes will also affect its availability.[49]

The Department of Energy (DOE) has prepared an atlas of potential geologic storage formations in North America.[50] That atlas indicates that there are potential storage formations of one kind or another underlying nearly all regions of the nation. Not all of these formations may be usable for permanent storage, however, and the unavailability or capacity limitations of some of the formations may have major consequences on the potential size, configuration, and cost of pipelines required to transport CO_2 emissions from major coal-fired power plants. [51]

4. Injection and storage.

Once the captured CO_2 has been treated, compressed and transported by pipeline to a storage site, the next step is to inject the CO_2 stream into the underground formation targeted for permanent storage. The expected storage period is suggested by estimates that the amount of CO_2 retained in appropriately selected and managed geological reservoirs would "likely" exceed ninety-nine percent over a 1,000 year period.[52]

47. *Southern Natural Gas Co*., *supra* note 26.

48. Paul W. Parfomak & Peter Folger, "*Pipelines for Carbon Dioxide (CO_2) Control: Network Needs and Cost Uncertainties*", CONG. RESEARCH SERV. REP. FOR CONG. (ORDER CODE RL34316) (Jan. 10, 2008), *available at* http://ncseonline.org/NLE/CRS/abstract.cfm?NLEid=1950, [hereinafter CRS REPORT ON PIPELINE NETWORK NEEDS].

49. The competing operational demands placed on a CO2 pipeline by EOR operations and CCS operations is discussed in some detail in Section III.C.4, *infra*.

50. U.S. DEPT. OF ENERGY, NAT'L ENERGY TECH. LAB., CARBON SEQUESTRATION ATLAS OF THE UNITED STATES & CANADA 15-17 (2007) http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlas/ [hereinafter *CO_2 Storage Atlas*].

51. To take just one example, it has been estimated that the difference in cost for transporting CO_2 from major Ohio Valley power plants for long term storage may increase by something on the order of twenty-fold – a difference of many billion dollars – if the plants were unable to use the closest deep saline aquifer (the Rose Run formation underlying Eastern Ohio, Western West Virginia, Maryland, and Pennsylvania) and were forced instead to carry the gas to the Mount Simon sandstone formation underlying Western Ohio, Eastern Indiana, and Southern Michigan. CRS REPORT ON PIPELINE NETWORK NEEDS, *supra* note 48, at 4-10.

52. IPCC SPECIAL REPORT, *supra* note 2, at 14. Retention over just a 100 year period was deemed "very likely." *Id*. The report defined "likely" as a probability between sixty-six and ninety percent and "very likely" as a probability of ninety to ninety-nine percent. *Id*.

There are three general types of geological formations that have been proposed for use for permanent storage, each of which presents a different mix of technical, policy, legal, or contractual issues (including subsurface pore space leasing rights issues). Because these differences are so pronounced it is extremely important to bear them in mind when discussing CCS regulatory proposals, because requirements that may be appropriate for one geologic formation type may be completely unnecessary or inapplicable for another. Hence, one would expect to see differing legal and regulatory requirements evolve depending largely on the nature of the geologic storage formation at issue.

a. Depleted oil and gas formations.

The best understood of the potential storage formations are depleted oil and gas formations. By definition, these formations have naturally-occurring trapping mechanisms (since the oil or gas originally in place would have migrated elsewhere had that not been the case). Accordingly, they tend to present attractive candidates for long-term storage with minimal and well-understood risks of leakage. Another attraction of these formations for carbon storage is that these are the type of formations used for the incidental storage of CO_2 in existing EOR operations and as a result many such sites are located by existing CO_2 pipeline and handling infrastructure that can be used (or adapted for use) for further CO_2 injection. The potential for adapting existing EOR sites, where CO_2 has been incidentally stored as part of oil production, to sites for incremental storage for CCS purposes is discussed in some detail below. Of note here are two principal limitations. First, the total estimated storage capacity of such formations, while large, is perhaps an order of magnitude or more below the estimated capacity of deep saline aquifer formations. This is shown in Figure 2 below.[53]

53. The table is derived from data published in the *CO_2 Storage Atlas*, *supra* note 50. Published estimates for capacity worldwide are summarized in THE FUTURE OF COAL, *supra* note 5, at 45. While it appears clear that large storage capacity exists, there remains very considerable uncertainty as to the actual amounts. *Id*. (noting more than two orders of magnitude variance between some estimates).

FIGURE 2

	DOE estimate of North American CO_2 storage capacity (billion metric tonnes) (rounded)	Years of current total US CO_2 emissions from power plants that could be stored[54] (rough estimate)
Mature Oil and Gas Reservoirs	82	33 years
Deep Unmineable Coal Seams	156 to 184	63 to 74 years
Deep saline aquifers	919 to 3,378	371 to 1364 years
TOTAL	1,158 to 3,644	

In addition, these formations are not evenly distributed around the United States (or the world) and therefore may require considerable investment in pipeline transportation assets to move the CO_2 from power plant source to geological sink.

Depleted oil and gas formations are expected to play a critical role in the initial phases of implementing CCS, because of the availability of existing CO_2 transport and injection facilities together with availability of the storage sites, and the developed knowledge of their reservoir dynamics.[55] The possibility of recouping some portion of the cost of CCS through the sale of oil produced through CO_2 injections in the initial phase of the process is also a potentially significant factor. In addition, as the original oil or gas in place in the reservoir had been trapped for millions of years prior to the commencement of production, such formations are likely to be viewed as the best sites from the standpoint of retaining stored CO_2 over lengthy – even geological – time periods. Last, since existing natural gas or petroleum pipelines already link many oil and gas producing regions with industrial and population centers, the required investment for transportation may be reduced somewhat to the extent portions of this existing infrastructure may be converted to CO_2 transport. Still, while oil and gas reservoirs appropriate for EOR injections are attractive early candidates for incremental CO_2 storage, the relatively limited capacity and geographic concentration away from many major CO_2 emissions sites suggest that they will not be adequate by themselves to accommodate total CO_2 emissions from United States industry.

54. Based on EIA estimate of US CO_2 emissions of approximately 2.476 billion metric tonnes from power plants (average for 2004-2006). EIA, ELECTRIC POWER ANNUAL tbl. 5.1 (2007) http://www.eia.doe.gov/cneaf/electricity/epa/epat5p1.html.

55. *See also* the discussion in Section III.E. 3 regarding procedures used by state oil and gas regulators in the context of utilization and pooling to evaluate formation boundaries and the potential for migration of fluids.

b. Deep, unmineable coal seams.

Deep unmineable coal seams have been deemed unsuitable for mining because they contain brine, methane, and other gases. A potential attraction of storing CO_2 in these formations is the possibility of using CO_2 injections to enhance the production of methane, a process known as enhanced coal bed methane production (ECBM).[56] While the technical mechanics of the gas production in such formations are different from CO_2-based enhanced oil recovery, the process is analogous in its use of CO_2 to produce hydrocarbons and thereby potentially may offset some portion of the CCS costs. As noted in the table above, the potential storage capacity of these formations is believed to be considerably larger than for oil and gas formations (perhaps twice as great), but still far less than deep saline aquifers.

c. Deep saline aquifers.

Deep saline aquifers are sedimentary rocks that are saturated with brine. The waters in these formations are not suitable for agricultural use or human consumption and hence do not normally constitute "underground sources of drinking water" that are the focus of the Safe Drinking Water Act (SDWA) discussed below.[57] The attraction of these formations for CO_2 storage is that they are generally plentiful and distributed more widely than are depleted oil and gas reservoirs. A number of these sites are also already used for disposal of hazardous and non-hazardous wastes under applicable rules of the EPA.[58] Many such formations are located at a depth in excess of 800 meters, which is the depth at which the ambient pressure and temperature will preserve injected CO_2 as a dense phase gas or supercritical fluid. As compared to oil and gas formations, however, there is greater uncertainty as to the physical trapping mechanism of CO_2 within these formations, the boundaries of which are typically not as well defined as being enclosed by cap rock, faults, or other geologic trapping mechanisms.

Similarly, there is greater uncertainty in many instances regarding potential migration pathways between these saline aquifer formations and underground sources of drinking water. Hence, there is a need for better understanding of the potential movement of an injected CO_2 "plume" through the brine, including the displacement of the water and the potential for chemical interactions between CO_2 and existing metals or minerals. As noted below, this uncertainty has implications for various aspects of proposed transactions, including compliance with regulatory rules to protect underground sources of drinking water, the extent of the surface and subsurface property rights required for a storage project, and the drafting of the applicable pore space leases to name but a few. In an effort to reduce these uncertainties, governments around the world have

56. For a discussion of ECBM, *see also* IPCC SPECIAL REPORT, *supra* note 2, at 217-219. A searchable database of CCS projects worldwide (including ECBM projects) has been developed by the International Energy Agency and is available to the public at: http://co2captureandstorage.info/co2db.php (last visited May 26, 2008).

57. Safe Drinking Water Act of 1974, 42 U.S.C §§ 300f - 300j-26, 300h(b)(2)(2006).

58. Such deep wells injecting below the lowermost underground source of drinking water are designated "Class I" wells. 40 C.F.R. § 144.6 (1999).

encouraged more research into the potential use of saline aquifers for CO_2 storage. Many of these research endeavors are still in early phases, however, and full results are not expected until 2010 or later.[59]

5. Monitoring, Verification, and Remediation.

Since the purpose of CCS is to ensure that the CO_2 does not enter the atmosphere, the injection of CO_2 for environmental storage purposes will require a system of verification, monitoring, and possible remediation that does not presently exist. This is necessary not only for ensuring public safety and accountability, but also for ensuring the integrity of any system of economic incentives that may be established to encourage CCS. These two considerations tend to imply very different types of verification and monitoring mechanisms, however.

Since CO_2 is itself non-toxic at normal atmospheric concentrations[60] and dissipates in the atmosphere over time, the principal potential public safety hazard from atmospheric releases would not normally arise from minute leakages over a long period of time but rather from a sudden, large-volume leak producing a high concentration of CO_2 in a low-lying area (due to the fact that CO_2 is heavier the ambient air), such as might occur from a blow-out at a storage reservoir or a major rupture of a CO_2 pipeline.[61] The object of a monitoring mechanism in such cases is to provide sufficient information to the operator of the facility (power plant, pipeline, or storage facility) to enable a rapid shut-down response to avoid damage to life and property. The level of sophistication in the monitoring mechanism required to detect such an event is not particularly great. An abrupt leak from a pipeline break for example would be immediately reflected in a loss of line pressure and would normally be observed immediately by the pipeline operator. A comparable major leak from an underground formation would similarly be reflected in a pressure change at the injection site. Hence, what would be required in such cases is not so much the creation of new monitoring equipment, or techniques, but rather the development of communications and crisis-management protocols to ensure that the operator can

59. U.S. DEPT. OF ENERGY, DOE AWARDS FIRST THREE LARGE-SCALE CARBON SEQUESTRATION PROJECTS (Oct. 9, 2007), http://www.fossil.energy.gov/news/techlines/2007/07072-DOE_Awards_Sequestration_Projects.html (announcing 197 million dollars research awards for large volume tests for CO_2 storage in deep saline reservoirs over ten years (subject to annual appropriations from Congress) testing storage in Alberta, Canada, the Williston Basin in North Dakota, the lower Tuscaloosa Formation Massive Sand Unit in the Southeast United States, and the Entrada Sandstone Formation in the Southwestern United States). The research projects announced by the Department of Energy in May of 2008 anticipate spending two years of research and preparation before CO_2 injections even begin. U.S. DEPT. OF ENERGY, ENERGY DEPT. AWARDS $66.7 MILLION FOR LARGE-SCALE CARBON SEQUESTRATION PROJECT (Dec. 18, 2007), http://www.fossil.energy.gov/news/techlines/2007/07084-Illinois_Basin_Sequestration_Proje.html (announcing demonstration project for one million tons in the Mount Simon Sandstone Formation, a geologic formation under much of Illinois, Kentucky, Indiana, and portions of Ohio; formation is said to offer "great potential" to store more than 100 years of carbon dioxide emissions from major point sources in the region).

60. IPCC SPECIAL REPORT, *supra* note 2, at 189, 391.

61. Other potential safety hazards have been identified. It has been suggested for example that CO2 leaking from a storage site into the soil could displace naturally occurring radon, causing radon accumulations that could have adverse health effects. Jeffrey W. Moore, *The Potential Law Of On-Shore Geologic Sequestration Of CO2 Captured From Coal-Fired Power Plants*, 28 ENERGY L.J. 443, 445 (2007) [hereinafter *J. Moore*].

respond in a timely fashion, notify the appropriate public safety authorities, and implement previously developed emergency response plans to mitigate potential harm. In this, the problem is roughly akin to the need for other energy infrastructure operators (for hydroelectric dams, LNG storage facilities, oil or natural gas pipelines, etc.) to prepare and maintain emergency action plans in conjunction with local law enforcement and public safety agencies. This of course is already addressed under existing state and federal safety regulations of CO_2 pipelines.[62]

With regard to the potential for CO_2 migration into underground sources of drinking water, the issues are analogous, but more complex. Under current regulation (discussed in detail in Section III.D), the existing universe of over 6,000 active CO_2 injection wells that are used for EOR purposes are categorized as "Class II" injection wells under the EPA's Underground Injection Control (UIC) program.[63] The EPA's well permitting process and regulations under the UIC are designed to protect underground sources of drinking water. Again, since pure CO_2 itself is non-toxic at normal atmospheric concentrations,[64] the public safety issue does not arise principally from the passage of a pure CO_2 stream itself into a source of drinking water but rather from either the introduction of contaminants that might have been injected with the CO_2, or from the interaction of the CO_2 with subsurface minerals in, or adjoining, an underground source of drinking water.

The first risk – of contaminants in the CO_2 stream – could be largely mitigated by requiring that the CO_2 stream, tendered for storage by operators of coal-fired generating stations, be free of contaminants if it is to qualify for incentives designed to encourage applicability of CCS technology to coal-fired power plants. With regard to the second risk, the EPA has commenced a rulemaking proceeding under its UIC program that seeks to address these potential risks (discussed below). The DOE is also funding considerable research into these issues, particularly with regard to gaining a better understanding of the movement of a CO_2 "plume" through a saline aquifer and the interactions of injected CO_2 with native rocks, minerals, and brine.[65]

A very different set of monitoring issues is presented with regard to checking for small leakages over long periods of time where the issue is primarily *economic*, not public safety. The concern is that a small leak over a long period of time that is far too small to present a public health concern could nonetheless compromise the integrity of an incentive program. The potential problem would arise where an economic benefit is received at the time the CO_2 is initially stored (*e.g.*, through receipt of an allowance or bonus allowance for carbon emissions reduction or via an offset credit program of one type or

62. *See, e.g.*, 49 C.F.R. §§ 195.401 - 195.404 (Department of Transportation regulations setting out requirements for safe operations, emergency training and emergency response planning procedures for, inter alia, CO_2 pipelines). Safety regulation for interstate CO_2 pipelines is provided by the federal government. Individual state governments regulate intrastate CO_2 pipelines under comparable requirements.

63. GWPC CO2 Well Survey, *supra* note 6.

64. IPCC SPECIAL REPORT, *supra* note 2, at 189, 391.

65. Information on these multiple research projects is available from the National Energy Technology Laboratory. *See generally* CARBON SEQUESTRATION REFERENCE SHELF, U.S. DEP'T OF ENERGY, NAT'L ENERGY TECH. LAB. http://www.netl.doe.gov/technologies/carbon_seq/refshelf/refshelf.html).

another) but where the CO_2 subsequently escapes to the atmosphere – perhaps decades after the incentive was provided and perhaps when the recipient of the incentive is no longer even in existence. The issue in such an instance would thus be aimed at ensuring that some entity will be responsible for continued maintenance on surface equipment and remediating the source of any leak with adequate funds available for any remediation work, including the resources to make whole the loss to the atmosphere of any significant amounts of the stored CO_2. It is anticipated that the financial security aspect of the ongoing monitoring, maintenance, and remediation process would need to be assured through either a government or privately-funded mechanism (or perhaps a combination of the two), as discussed in more detail below.

D. Summary.

This, in a nutshell, is the current industry for which a basic legal and regulatory framework already exists with regards to the incidental storage of CO_2 in the context of EOR operations. As policy makers rush to create rules for *incremental* storage of CO_2, in the context of general regulation of carbon emissions, it may be wise to recall that such rules would govern an industry that may or may not come into existence in the next decade or more, or that may evolve in unexpected directions. Still, the above factual outline provides a rough working basis to bear in mind as we review the legal framework for the existing EOR industry. As will become apparent from that review, the existing legal and regulatory framework appears largely adequate to govern, at least the beginning of a transition, from a world in which CO_2 is injected and incidentally stored during EOR operations, to one in which incremental volumes are stored as part of an evolving CCS industry, while certain aspects of the legal and regulatory framework, however, could be significantly enhanced with fairly minor changes

III. OVERVIEW OF EXISTING LEGAL FRAMEWORK FOR PURCHASE, TRANSPORT, INJECTION AND STORAGE OF CO_2

Assuming a source of CO_2 has been acquired and is planned for shipment by pipeline to an EOR production site, a series of legal questions need to be addressed. These include: (a) determining the legal framework governing the purchase and delivery of the CO_2; (b) establishing applicable quality specifications for "pipeline-quality" and "EOR-quality" CO_2; (c) acquiring rights of way for new pipeline construction; (d) allocating liability among the parties for failure to perform (including seller's failure to meet the quality specifications of the CO_2 being tendered for delivery and purchaser's failure to take the tendered CO_2); and (e) obtaining and managing the various property rights, including in particular necessary agreements with surface owners, mineral interests owners, and royalty interest owners. These kinds of practical "commercial transactions" and "oil and gas law" issues have generally not been addressed in the various studies published in recent years examining legal and regulatory considerations raised by proposals for geologic storage of CO_2.[66]

66. Most of the published studies focus instead on international legal issues (such as agreements governing the injection of wastes or other materials in the North Sea or other international waters) or on the permitting and regulatory framework for injection and storage. *See, e.g.*, INT'L ENERGY ADMINISTRATION,

While the draft Model Statute and Model CCS Rules, published by the Interstate Oil and Gas Compact Commission,[67] is very useful for addressing permitting issues (and is discussed below), it does not speak to some of the issues that arise further "upstream", *i.e.*, in the acquisition and pipeline transportation of the CO_2, or further "downstream," where a mineral owner has oil yet remaining in the storage reservoir. Hence we begin by reviewing some of the existing legal framework for CO_2-based EOR, flagging issues likely to be faced by practitioners involved in assisting clients in CO_2-related transactions and seeking to identify which aspects of the existing rules can be readily adapted to EOR injections for CCS and some new contractual resolutions proposed by the authors.

A. The Legal Framework for Commercial Purchase and Sale of CO_2: is CO_2 a "good" thing under the Article 2 of the Uniform Commercial Code?

A threshold issue in crafting a CO_2 acquisition or Off-Take Agreement is whether or not the transaction is subject to the Uniform Commercial Code (UCC). Article 2 of the UCC applies of course to transactions in "goods." Section 2-105 defines the term "goods" in relevant part as "all things... which are movable at the time of identification to the contract for sale."[68] Section 2-107 more specifically addresses the sale of minerals or the like ("including oil and gas")[69] that are "to be removed from realty."[70] That section provides that a contract for such a sale "is a contract for the sale of goods"[71] under Article 2 of the UCC "if they are to be severed by the seller."[72] The Official Comment notes that "[i]f the buyer is to sever, such transactions are considered contracts affecting land and all problems of the Statute of Frauds and of the recording of land rights apply to them."[73]

Hence a textual reading of the UCC suggests that sales of naturally-occurring CO_2 produced from a geological reservoir (*i.e.*, severed from the realty) may be governed by the UCC as "goods" under Section 2-107 much as

LEGAL ASPECTS OF STORING CO_2 – UPDATE AND RECOMMENDATIONS (Int'l Energy Administration, 2007), and the draft discussion paper of the same, Int'l Energy Admin., *Legal Aspects of Storing CO_2 – Update and Recommendations* (2007), INTERNATIONAL ENERGY ADMIN. & THE CARBON SEQUESTRATION LEADERSHIP FORUM JOINT WORKSHOP ON LEGAL ASPECTS OF CARBON CAPTURE & STORAGE IN PARIS, FRANCE (Oct. 17, 2006), http://www.cslforum.org/documents/iea_cslf_Paris_Discussion_Paper_CCS.pdf). For a study of legal issues associated with five existing CCS projects around the world, *see generally*, NAT'L ENERGY TECH. LAB., INT'L CARBON CAPTURE & STORAGE PROJECTS – OVERCOMING LEGAL BARRIERS (2006), http://www.netl.doe.gov/energy-analyses/pubs/ccsregulatorypaperfinalreport.pdf (examining CCS projects in Australia (Gorgon project), Algeria (In Salah project), Norway (Sleipner project), Poland (RECOPOL project), and Germany (CO2SINK project)).

67. INTERSTATE OIL & GAS COMPACT COMM'N, TASK FORCE ON CARBON CAPTURE & GEOLOGIC STORAGE, STORAGE OF CARBON DIOXIDE IN GEOLOGIC STRUCTURES A LEGAL AND REGULATORY GUIDE FOR STATES AND PROVINCES (2007), http://www.iogcc.state.ok.us/docs/2007-CO2-Full-Report.pdf.

68. U.C.C. § 2-105 (2004).

69. *Id*. § 2-107.

70. *Id*.

71. *Id*.

72. *Id*.

73. *Id*. cmt. 2.

similar sales of natural gas.[74] Anthropogenically-sourced CO_2, on the other hand, is captured from an industrial facility, or a coal-fired power plant, and, being man-made, would not appear to fit the Section 2-107 text of a mineral "to be removed from realty."[75] It may, perhaps, come within the general rule for "things" that are "movable at the time of identification to the contract"[76] under Section 2-105 or "specially manufactured" goods made to conform to a special order.[77] While the question is not entirely clear, it may not require further clarification if the removal of CO_2 from the premises of an industrial facility (particularly under a regime where CO_2 emissions are regulated) were viewed as part of an integrated off-take removal and storage service without which the facility would not be able to operate. Such an off-take, removal and storage *service* would presumably not come within the UCC's rules governing transactions in "goods" at all.

While there does not appear to be case law addressing anthropogenic CO_2 arising in the CCS context, there is case law treating sales of CO_2 in other contexts as subject to the UCC.[78] For example, in *Rock Creek Ginger Ale Company, Inc. v. Thermice Corporation*,[79] the court reviewed a dispute concerning the sale by a brewer of defective CO_2 that was sold to a CO_2 distributor.[80] The defective CO_2 was then resold to a soft drink bottler. In applying the UCC provisions governing use of samples,[81] the court appeared to hold that the brewer had created an express warranty that the quality of the CO_2 to be delivered under the contract would conform to the quality of the sample initially provided.[82] Subsequent delivery of CO_2 supplies that fell below that quality was thus a breach of the warranty.[83] In *Rock Creek*, the seller apparently did not claim that the UCC warranty had been disclaimed. In any event, the court noted that the general policy is to not give effect to such disclaimers, quoting the Official Comment to Section 2-313(c):

> In view of the principle that the whole purpose of the law of warranty is to determine what it is that the seller has in essence agreed to sell, the policy is adopted of those cases which refuse except in unusual circumstances to recognize a material deletion of the seller's obligation. Thus, a contract is normally a contract for a sale of something describable and described. A clause generally disclaiming "all warranties, express or implied" cannot reduce the seller's obligation with

74. *See, e.g.*, Southern Natural Gas Co. v. Pursue Energy, 781 F.2d 1079, 1081 n.3 (5th Cir. 1986) *citing* Miss. Code Ann. Sec. 75-2-107(1) (1972) (natural gas transactions at issue governed by Article 2 of the Mississippi Uniform Commercial Code). The case was a diversity case in Federal court that applied Mississippi law. *See also* Piney Woods Country Life School v. Shell Oil Co., 726 F.2d 225, 231-32 (5th Cir. 1984) (applying Mississippi version of U.C.C.).

75. U.C.C. § 2-107 (2004)

76. *Id*. § 2-105.

77. *Id*.

78. *See, e.g.*, Rock Creek Ginger Ale Co. v. Thermice Corp., 352 F. Supp. 522, 523-530 (Dist. DC 1971) (sales of surplus CO2 by beer brewer to a reseller for use by a soft drink bottler) [hereinafter *Rock Creek*].

79. *Id*.

80. *Id*.

81. *Id*. at 526-528. The court also noted case law to the same effect. *Id*. (citations omitted). U.C.C. § 2-313(c) provides that "Any sample or model which is made part of the basis of the bargain creates an express warranty that the whole of the goods shall conform to the sample or mode." *Id*.

82. *Rock Creek*, *supra* note 78, at 529-530.

83. *Id*.

respect to such description and therefore cannot be given literal effect under Section 2-316.[84]

Another point of interest to sellers who produce CO_2 as a byproduct of their electricity generating or other operations, however, is the separate question of whether the brewer in *Rock Creek* was subject to an *implied* warranty (which would apply only if the brewer was a "merchant" of CO_2 within the meaning of UCC 2-314(1).[85] The District Court there upheld the brewer's claim that it was a manufacturer and merchant *of beer*, not of CO_2 (which was surplus to its brewing endeavors). Accordingly, the court found that the brewer was not subject to the implied warranty provisions applicable to a "merchant with respect to goods of that kind."[86] The court relied in particular on Official Comment 3 which notes that "[a] person making an isolated sale of goods is not a 'merchant' within the meaning of the full scope of this section and, thus, no warranty of merchantability would apply."[87]

Even though the CO_2 sales in question were large (700,000 pounds) and had continued for some six months, the court was apparently persuaded that the sales were sufficiently "isolated" in the context of the brewer's overall business such that the court concluded that the brewer was not a merchant of CO_2 and therefore not subject to the implied warranty. [88]

Other examples of sales of manufactured CO_2 being treated as goods under the applicable UCC may be found in various contracts or government procurement documents.[89]

While the CO_2 sales in *Rock Creek* were addressed under the UCC, CO_2 sales under an Off-Take Agreement from an electricity generating or other industrial facility might also be viewed as a service that is not within the terms of the UCC. The argument would be that the removal of the CO_2 formed part of the necessary process without which the plant could not lawfully operate. If viewed as a service, such transactions might be viewed as analogous to the sale of electricity as a service, which is a legal conclusion adopted by courts in a number of states. Indeed, billions of dollars worth of electricity were traded in the 1990s when the status of electricity sales under the UCC of the various states

84. *Id*. at 527; *see also* Neville Chemical Co. v. Union Carbide Corp., 422 F.2d 1205, 1220 (3rd Cir. 1970) (where specific language was employed in an effort to avoid the binding aspects of a sale by sample but was rejected both by the trial court and the Third Circuit).

85. U.C.C. § 2-314(1) states in relevant part that: "Unless excluded or modified, a warranty that the goods shall be merchantable is implied in a contract for their sale if the seller is a merchant with respect to goods of that kind."

86. *Rock Creek*, *supra* note 78, at 527-528

87. U.C.C. § 2-314 cmt. 3.

88. *Rock Creek*, *supra* note 78, at 528.

89. One example is the State of Iowa purchase contract specifications for purchasing CO_2 and other "industrial and medical gases" (argon, nitrogen, etc.) as subject to the U.C.C. (requiring vendor to expressly warrant that all goods supplied shall be merchantable in accordance with the Uniform Commercial Code section 2-314 and the Iowa Code, section 554.2314. *See also* the Bid Documents for the purchase of carbon dioxide delivered via vehicles with storage tanks to the GENERAL SERV. DEP'T, WATER SUPPLY DIVI. OF CONCORD, NH, www.ci.concord.nh.us/PURCHASING/pdf/B44-03percent20Complete.pdf (last visited May 7, 2008) (requiring seller to agree to hold the City harmless "from any liability arising under RSA 382-A, 2-312 (3))" (relating to warranty of title).

remained unclear in many cases.[90] In New York and Massachusetts for example, electricity has been determined by the courts to not be a "good" within the meaning of Article 2 of the UCC in those states, but rather a non-UCC service. In the New York case of *Encogen Four Partners v. Niagara Mohawk Power Corporation*,[91] the court concluded that "[u]nder New York law...the sale of electricity does not constitute a sale of goods, but a service."[92] As a result, the court initially rejected a buyer's efforts to avoid a contractual obligation by terminating the agreement due to the seller's failure to provide adequate assurances of performance (as would have been required under UCC 2-609).[93]

In the Massachusetts case, *New Balance Athletic Shoe, Inc. v. Boston Edison Co.*,[94] the court could not have posed the question more clearly:

> Accordingly, the critical question raised by this motion is whether electricity is a "good" as defined in the [UCC]. If the answer to this question is in the affirmative, as New Balance asserts, then the sale of electricity may be subject to the warranty provisions of the [UCC]. If so, then upon this record, an action for breach of warranty may survive summary judgment scrutiny. If, however, electricity is found not to be a "good" as defined by the [UCC], the warranties in the [UCC] would not apply...[since the applicable] UCC provision applies only to the sale of "goods'.[95]

After reviewing precedents from several other states and considering the policy implications of subjecting utilities to product liability claims, the Massachusetts court determined that electricity is *not* a good, but rather a service.[96]

In contrast, a number of other cases have clearly held that sales of electricity by public utility companies do involve the sale of a "good" within the meaning of the UCC.[97] Thus, courts in some states have held that public utilities may be subject to liability for violating the UCC's implied warranties,[98] at least where the electricity has passed the customer's electric meter.[99] An Indiana court supported this conclusion by finding that electricity is a thing existing and

90. Philip M. Marston, *Power May be Good or Service under Law*, 14 NATURAL GAS 11, 30 (June 1998)(discussing contradictory precedents).

91. 914 F. Supp. 57, 61 (S.D.N.Y., 1996).

92. *Id*.

93. *Id*. Ultimately, however, the New York courts – after fairly complex litigation – reached a result under non-U.C.C. law that was roughly comparable to the result that would have obtained had the U.C.C. applied. *See also* Norcon Power Partners v. Niagara Mohawk Power Corp., 163 F.3d 153 (2d Cir. 1998).

94. 1996 WL 439396 (Mass. 1996).

95. *Id*. (internal citations omitted).

96. *Id*. at *3.

97. Helvey v. Wabash County REMC, 278 N.E. 2d 608 (1972); Baldwin-Lima-Hamilton Corp. v. Superior Court, 208 Cal. App. 2d 803, 819 (1962) (electricity "is a commodity which, like other goods, can be manufactured, transported and sold"); and Cincinnati Gas & Elec. Co. v. Goebel, 502 N.E. 2d 713, 714 (1986) (electricity is a "good" with in the U.C.C.). In addition, following the disruptions in the California energy markets 2000-2001 and the ensuing bankruptcies, the court in Puget Sound Energy, Inc. v. Pacific Gas & Electric Co., 271 B.R. 626, 640 (N.D. Cal. 2002) engaged a detailed review of the precedents in various states before ruling that electricity was a "good" within the meaning of the applicable U.C.C.. S*ee also* Enron Power Marketing, Inc. v. Nevada Power Co., 2004 WL 2290486 (S.D.N.Y. 2004), *opinion supplemented*, 2004 WL 3015256 (S.D.N.Y. 2004) (reaching same result under law of Utah (by relying principally on California, not New York, precedent)).

98. Helvey, *supra* note 97.

99. Petroski v. N. Ind. Pub. Serv. Co., 354 N.E. 2d 736 (1976).

moveable stating that "[l]ogic would indicate that whatever can be measured in order to establish the price to be paid would be indicative of fulfilling both the existing and moveable requirements of goods."[100]

It is too early to know for certain whether courts reviewing disputes under CO_2 Off-Take Agreements from industrial or power plant facilities will view the transaction as involving the sale of a good or a service, or whether (assuming the UCC were found to apply) the supplier would be held to be a "merchant with respect to goods of that kind"[101] – and therefore subject to the UCC implied warranty of merchantability under UCC 2-314(1).[102]

In light of this uncertainty, practitioners drafting such an agreement may tend to draft the contract as though it were subject to the UCC while recognizing that the UCC may in fact never be found to apply. For example, the parties might include a "UCC contingency clause" under which the parties agree that if the state whose laws govern the transaction were to determine that CO_2 is a "good" for purposes of the UCC, then except as specifically otherwise provided, the agreement would be deemed subject to the UCC. The parties could then, if they chose, include an express disclaimer of warranties (in an appropriately "conspicuous" writing[103]), including any warranty with respect to merchantability or fitness for any particular purpose.

The provisions regarding disclaimers in paragraph (2) of UCC Section 2-316 are made subject to paragraph (3)[104], however, which provides that there may be no implied warranty in instances where it has been excluded or modified by a course of dealing, or course of performance or usage of trade[105], or where the "buyer before entering into the contract has examined the goods or the sample or model as fully as he desired or has refused to examine the goods... with regard to defects which an examination ought in the circumstances to have revealed to him."[106] Especially in light of *Rock Creek*,[107] parties to contracts involving anthropogenic CO_2 may wish to be very careful in terms of considering whether samples of the CO_2 output have been tendered for analysis in such a way as to effectively modify the quality standards or warranties under the UCC (should the UCC be found to apply). Similarly, the operating personnel should be aware that their course of dealing and course of performance in operating under the agreement may be found to effectively alter contract terms if UCC section 2-316 (3)(c) is determined to apply.

Parties contracting to receive CO_2 for EOR purposes should plan for these risks by reserving an explicit option to take or reject non-conforming supplies and a right to take or contract for alternative supplies if the contract supplier is unable to meet the contract specifications for a certain period. In such a case,

100. Helvey, *supra* note 97, at 610.

101. U.C.C. § 2-314 (1) (2004).

102. *Id*.

103. Language to exclude or modify the implied warranty of merchantability or any part of it "must mention merchantability and in case of a writing must be conspicuous, and that to exclude or modify any implied warranty of fitness the exclusion must be by a writing and conspicuous." *Id*. §§ (2).

104. *Id*. §§ (2)-(3)

105. *Id*.

106. U.C.C. § 2-316 (3)(b) (2004).

107. *Rock Creek*, *supra* note 78.

when the contract supplier has returned to meeting the quality specifications, he should also normally be required to provide some reasonable notice to recipient to allow for termination of the alternative interim arrangement.

In sum, parties to CO_2 contracts over the next several years may find it wise to draft agreements as though the UCC might be found to apply in the event of a dispute, while recognizing that disputes may well end up being resolved through the application of general contract law (*e.g.*, Restatement of the Law Second of Contracts, tort law, etc.).

B. Defining CO_2 Quality: "Pipeline Quality," "EOR Quality," and "Storage Quality."

Regardless of whether the CO_2 acquisition or shipping contract is subject to the UCC, it will need to detail applicable quality specifications. At present, there does not as yet appear to be any industry-wide standard for potentially distinct categories of "pipeline quality," "EOR quality," or "CCS storage quality" CO_2, although it appears that different minimum standards may be appropriate for these different purposes.

The issues may be illustrated by considering the question of nitrogen content in a CO_2 stream. Relatively higher levels of nitrogen (or other inert gases) in the CO_2 stream during pipeline transportation would tend to increase the cost of transporting the CO_2 (by taking up pipeline space and requiring additional compression), but would not in and of itself (within a fairly wide tolerance) interfere with the transportation service itself. For EOR operations, however, excessive nitrogen content could interfere with the CO_2's role in oil production operation,[108] and would therefore need to be removed prior to use. Hence, if the pipeline were carrying gas principally or exclusively intended for EOR operations (as are all existing CO_2 pipelines), the pipeline operator would be expected to apply a more restrictive standard. Importantly, however, except for limitations on CO_2 mole percent, H_2S concentration, and extraneous contaminants that could damage a reservoir or cause operational difficulties, the source of the CO_2 (whether from manufacturing, electricity generation or production from geologic sources) is immaterial.[109]

In a "pure-play" CCS project, however, (where the CO_2 is never to be used for EOR injections at all) the situation would appear to be more analogous to the pipeline transportation scenario: while the nitrogen might not interfere with the storage of the CO_2 in the geologic formation, it would still take up valuable space in the storage formation that could otherwise be used for storing the CO_2 and would require additional energy for injection, thereby increasing costs. In this case, the nitrogen specification would involve primarily economic issues and would be negotiated between the parties.

Similarly, acceptable levels of water or water vapor in the CO_2 stream may vary depending on the anticipated use. Water content is a potentially significant issue for CO_2 transport because while dry CO_2 is not corrosive, the introduction of free water into a CO_2 stream tends to increase corrosion. Accordingly,

108. IPCC SPECIAL REPORT, *supra* note 2, at 30.

109. Different quality specifications are required for "food-grade" CO_2.

existing CO_2 pipeline quality specifications generally prohibit the inclusion of free water and sharply limit the presence of water vapor in CO_2 tendered for transport, even though the injection of water into a deep saline storage formation might itself not pose any problems (since by definition there is already water present in such a formation).[110] Similar restrictions would appear likely to be incorporated in any CCS project to minimize the risk of corrosion in injection wells and related facilities (although the CO_2 after injection will of course come into contact with water in an aquifer storage formation). In sum, while the details are different, these kinds of gas quality standards are directly analogous to the quality specifications in the tariffs of natural gas pipelines, a topic with which many energy practitioners are thoroughly familiar.[111]

C. Regulation of CO_2 pipelines

1. Safety regulation by the United States Department of Transportation.

The Pipeline and Hazardous Materials Safety Administration (PHMSA) of the Department of Transportation (DOT) is responsible for pipeline safety regulation under the Hazardous Liquid Pipeline Act of 1979.[112] This responsibility is carried out within PHMSA by the Office of Pipeline Safety (OPS). Under the 1979 act, the DOT regulates the design, construction, operation and maintenance, and spill response planning for CO_2 pipelines.[113] The DOT regulations are also generally followed by state regulators in order to exercise safety regulation over the intrastate CO_2 pipelines. For purposes of the

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110. The CO_2 quality specifications from a Permian Basin CO_2 pipeline are reproduced in the IPCC SPECIAL REPORT, *supra note* 2, at 182. The quality specifications in that particular case provide that CO_2 tendered for transport must meet the following quality specifications:

> (a) Carbon Dioxide. Product shall contain at least ninety-five mole percent (95%) of Carbon Dioxide as measured at the SACROC delivery meter.
>
> (b) Water. Product shall contain no free water, and shall not contain more than 0.48 9 m^{-3} in the vapour phase.
>
> (c) Hydrogen Sulphide. Product shall not contain more than fifteen hundred (1500) parts per million, by weight, of hydrogen sulphide.
>
> (d) Total Sulphur. Product shall not contain more than fourteen hundred and fifty (1450) parts per million, by weight, of total sulphur.
>
> (e) Temperature. Product shall not exceed a temperature of 48.9^{o} C.
>
> (f)Nitrogen. Product shall not contain more than four mole percent (4%) of nitrogen.
>
> (g) Hydrocarbons. Product shall not contain more than five mole percent (5%) of hydrocarbons and the dew point of Product (with respect to such hydrocarbons) shall not exceed –28.9^{o} C.
>
> (h) Oxygen. Product shall not contain more than ten (10) parts per million, by weight, of oxygen.
>
> (i)Glycol. Product shall not contain more than 4 x 10^{-5} L m^{-3} of glycol and at no time shall such glycol be present in a liquid state at the pressure and temperature conditions of the pipeline.

Id.

111. *Policy Statement on Provisions Governing Natural Gas Quality and Interchangeability in Interstate Natural Gas Pipeline Company Tariffs*, 115 F.E.R.C. ¶ 61,325, 62,156 (2006) [hereinafter *Policy Statement*]; NATURAL GAS COUNCIL, NGC+ INTERCHANGEABILITY WORK GROUP, WHITE PAPER ON NATURAL GAS INTERCHANGEABILITY & NON-COMBUSTION END USE (2005), http://www.beg.utexas.edu/energyecon/lng/documents/NGC_Interchangeability_Paper.pdf. For a recent Commission order addressing natural gas quality specifications, *see generally Northern Natural Gas Company*, 121 F.E.R.C. ¶ 61,122 (2008).

112. 49 U.S.C. § 60101 (2006).

113. *Id*. § 60102. *See also* 49 C.F.R. § 190, 195-199.

DOT safety regulations, "carbon dioxide" is defined as a supercritical fluid, not a liquid:[114] "carbon dioxide means a fluid consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state."[115]

Indeed, while CO_2 pipelines are subject to the same regulations as pipelines transporting hazardous liquids (such as petroleum, petroleum products, and anhydrous ammonia), the DOT regulations do not classify CO_2 as a hazardous liquid but rather a Class 2.2 (non-flammable gas) hazardous material.[116]

The PHMSA rules specify design rules for all affected pipelines (generally excepting upstream, injection area, and plant area facilities).[117] In addition to general rules governing pipe thickness, the rules set performance standards for CO_2 pipelines and require that the pipe chosen be appropriate for the actual composition of the materials.[118] The rules also address the conversion of steel pipeline originally used for other substances (which would of course include natural gas pipeline).[119] The conversion rules generally require a review of the design, construction, operation, and maintenance history of the pipe, inspection of the right of way, and testing to substantiate the maximum operating pressure permitted by the PHMSA regulations.

With regard to the safety record of CO_2 pipelines, there were no reported fatalities or personal injuries over the twenty years from 1986 to 2006 attributable to CO_2 pipelines, although some twelve leaks were reported during that period. This compares favorably with over 5,600 accidents over that same period related to natural gas or other non-CO_2 pipelines (which caused 107 fatalities and some 520 injuries).[120] If a nationwide network of CO_2 pipelines were constructed as part of a nationwide CCS industry, one would expect the

114. 49 C.F.R. § 195.2.

115. *Id*.

116. While CO_2 is not technically a "hazardous liquid" under the DOT regulations, some confusion on this point has arisen from the fact that the applicable regulations are included the heading assigned to Part 95 of the Department's Regulations, which is entitled "Transportation Of Hazardous Liquids By Pipeline." 49 C.F.R. pt. 95. At the time the rules were developed, commenter's had pointed out the potential for confusion and requested that the regulations for CO_2 pipelines be included in a separate part of the regulations. While the DOT made it clear in the rule's preamble that that it was not classifying CO_2 as a hazardous liquid, for administrative convenience it retained the regulations governing CO_2 pipelines regulations within the section addressing such liquids. Hence the table at 49 C.F.R. § 172.101 (Hazardous Materials Table) classifies CO_2 in class 2.2, while 49 C.F.R. § 195.2 defines the term "hazardous liquid" as "petroleum, petroleum products, or anhydrous ammonia" while defining carbon dioxide "a fluid consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state." The distinction between carbon dioxide and hazardous liquids is maintained at 49 C.F.R. § 195.0 which essentially provides that "[t]his part prescribes safety standards and reporting requirements for pipeline facilities used in the transportation of hazardous liquids or carbon dioxide." *Id*.

117. 49 C.F.R. § 195.106 (internal design pressure formulae).

118. 49 C.F.R. § 195.4 prohibits pipeline transportation of CO_2 unless it is "chemically compatible with both the pipeline, including all components, and any other commodity that it may come into contact with while in the pipeline."

119. 49 C.F.R. § 195.5. As noted above, in 2006 a little used natural gas pipeline lateral was abandoned by sale to a CO2 pipeline operator for conversion to CO_2 transportation to support EOR operations. *Southern Natural Gas Company*, *supra* note 26.

120. PAUL W. PARFOMAK & PETER FOLGER, CARBON DIOXIDE (CO_2) PIPELINES FOR CARBON SEQUESTRATION: EMERGING POLICY ISSUES 16 (January 17, 2008) http://assets.opencrs.com/rpts/RL33971_20080117.pdf [hereinafter CO_2 PIPELINES: EMERGING POLICY ISSUES 2008].

number of accidents to rise. Published analyses estimate that "the number of incidents involving CO_2 [pipelines] should be similar to those for natural gas transmission."[121] Due to the nonflammable and non-toxic nature of CO_2 the risk of explosive damage to life or property is far less than that presented by a natural gas pipeline. [122]

2. Economic regulation of rates, access, and eminent domain

> *"Questions of jurisdiction, of course, should be given priority – since if there is no jurisdiction there is no authority to sit in judgment of anything else."*
>
> -- Vermont Agency of Natural Res. v. US ex rel. Stevens[123]

A century and a half ago, in discussing the power of federal courts, the Supreme Court stressed the extent to which jurisdiction is a threshold to the exercise of legitimate power: "Jurisdiction is power to declare the law, and when it ceases to exist, the only function remaining to the court is that of announcing the fact and dismissing the cause."[124]

Hence, the threshold issue for reviewing the regulatory status of CO_2 pipelines under existing law is whether the construction and operation of such pipelines come within agency jurisdiction – whether any such agency has the "the power to declare the law."[125] As detailed below, this question was settled many years ago with respect to the Federal agencies charged with economic regulation under the Natural Gas Act and the Interstate Commerce Act, with findings that those statutes did not confer regulatory jurisdiction over CO_2 pipelines. The Bureau of Land Management (BLM), on the other hand has been found to have the legal authority to impose common carrier obligations on certain CO_2 pipelines that cross federal land. With regard to state law, the situation is more complex, with varying forms of carriage responsibilities being imposed on CO_2 pipelines depending on a number of different factors.

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121. *Id*. *citing* JOHN BARRIE ET AL., CARBON DIOXIDE PIPELINES: A PRELIMINARY REVIEW OF DESIGN AND RISKS (2004), http://uregina.ca/ghgt7/PDF/papers/peer/126.pdf. *See also* Commission Staff Working Document Accompanying Proposal For A Directive Of The European Parliament and Of The Council On The Geological Storage Of Carbon Dioxide Summary Impact Assessment, EUR. PARL. DOC. (SEC 55) ¶¶ 76-77 (2008) *citing* John Gale and John Davidson, *Transmission of CO2: safety and economic considerations*, 29 ENERGY 1319, at 1319-1328 (2004).

122. For more general discussion of CO_2 pipeline design considerations IPCC SPECIAL REPORT, *supra*, note 2, at Ch. 4.

123. Vermont Agency of Natural Res. v. U.S. ex rel. Stevens, 529 U.S. 765, 778 (2000).

124. *Ex parte* McCardle, 74 U.S. 506, 514 (1868), *see also* Steel Co. v. Citizens For Better Env't, 523 US 83, 94 (1998) *quoting McCardle* and *citing* other cases.

125. McCardle, 74 U.S. at 514.

a. Jurisdictional status under the Interstate Commerce Act and the Natural Gas Act: the Cortez rulings

i. CO_2 Pipelines under the Interstate Commerce Act.

When originally adopted in 1906, the Hepburn Act[126] added regulation of oil pipelines as common carriers to the pre-existing regulatory responsibilities of the Interstate Commerce Commission (ICC). The statute originally extended the provisions of the Interstate Commerce Act (ICA) to those "engaged in the transportation of oil or other commodity, except water and except natural or artificial gas, by means of pipe lines."[127] The exact wording of the ICA pipeline provisions changed several times over the years due to the transfer of oil pipeline regulation to the Federal Energy Regulatory Commission (FERC) in 1977 under the Department of Energy Organization Act[128] and the recodification of the US Code in 1978 (which deleted the qualifiers "natural or artificial", leaving the exclusion of simply "gas"). Following these changes, the FERC has regulatory jurisdiction over oil pipelines, while the transportation of a commodity "other than water, gas, or oil"[129] remained subject to regulation under the Interstate Commerce Act.[130] As a result there was a question as to the regulatory status of other naturally occurring gases (including helium and CO_2): did the exclusion of "natural or artificial gas" exclude non-heating gases that were naturally occurring gas such as CO_2?

This was the question presented by a pair of requests for declaratory order filed with the ICC nearly thirty years ago on behalf of Cortez Pipeline Company and ARCO Oil and Gas Company in conjunction with the construction of a new interstate CO_2 pipeline.[131] Cortez sought a ruling from the ICC that its pipeline would not be subject to common carrier regulation under the ICA while a similar petition for a declaratory order was submitted by ARCO Oil and Gas Company. In view of the precedential nature of the filing, the ICC invited general public comment on the requests before ruling.[132] Based on its legislative analysis, the ICC published a tentative conclusion that CO_2 was a "gas" within the meaning of the applicable statute and therefore not subject to its jurisdiction.[133] "The plain meaning of the... act... is that the universe of gas types classified by origin or source was excluded. It is therefore our tentative conclusion that we lack jurisdiction over the transportation of [CO_2] by pipeline.[134]

126. 34 Stat. 584, 59th Cong., 1st. Sess. 1, ch. 3591, enacted June 29, 1906.

127. *Id*.

128. Section 402 (b) of the Department of Energy Organization Act, originally codified at 42 U.S.C. 7172 (b), *repealed* by Pub. L. 103-272, 108 Stat. 1379 [hereinafter DOE Organization Act].

129. 49 U.S.C. 15301(a) (2006).

130. *Id*.

131. *See generally*: *Cortez Pipeline Company*, 45 Fed. Reg. 85177 (Dec. 24, 1980) (Petition for Declaratory Order – Commission Jurisdiction over Transportation of Carbon Dioxide by Pipeline) ("Tentative Declaratory Order") (internal citations omitted); and *Arco Oil and Gas Company*, 46 Fed. Reg. 18805 (Mar. 26, 1981) (Petition for Declaratory Order – Jurisdiction Over Interstate Pipeline Transportation of Carbon Dioxide) ("Final Declaratory Order") [hereinafter *Cortez-Arco Final Declaratory Order*].

132. *Cortez Pipeline Company*, 45 Fed. Reg. 85177.

133. *Id*.

134. *Id*.

Following the opportunity for public comment on its tentative conclusion, the ICC issued its final declaratory order affirming its tentative ruling and declaring that the interstate pipeline transportation of CO_2 gas is not subject to its jurisdiction.[135]

A final legislative change took place with the Interstate Commerce Commission Termination Act of 1995 (ICC Termination Act), which abolished the ICC, created the Surface Transportation Board (STB), and made a number of other changes.[136] The termination of the ICC and creation of the STB made no change in the substantive law governing pipelines, retaining the existing formulation that jurisdiction extended to the interstate transportation by pipeline of "a commodity other than water, gas or oil."[137] The savings provisions of the ICC Termination Act effectively confirmed the ongoing validity of the prior declaratory orders as section 204 of the ICC Termination Act specifically provides that all orders and determinations issued by the ICC in the performance of a function that was transferred to the STB by the ICC Termination Act "shall continue in effect according to their terms until [changed] in accordance with [the] law."[138] Accordingly, it seems clear under current law that the interstate transportation of supercritical CO_2 by pipeline is not subject to STB regulation under the ICA.[139]

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135. *Cortez-Arco Final Declaratory Order*, *supra* note 131.

136. Interstate Commerce Commission Termination Act of 1995 (ICCTA), Pub. L. No. 104-88, 109 Stat. 803 (1995) [hereinafter ICCTA].

137. As amended by the Termination Act, section 15301 of the Interstate Commerce Act, 49 U.S.C. 15301(a) (2006) provides in material part that the Surface Transportation Board has jurisdiction over "transportation by pipeline, or by pipeline and railroad or water, when transporting a commodity other than water, gas, or oil." *Id*.

138. ICCTA, *supra* note 137, § 204(a). The saving provision was not included in the codification of the Termination Act, but may be found in the notes to the codification of the sections establishing the Surface Transportation Board (STB). *Id*. As recognized by the STB itself, the saving provision of ICCTA "provides that ICC precedent applies to the Board." Surface Transp. Bd., GWI Switching Serv., LP, Finance Docket No. 32481 (Aug. 7, 2001), *available at* http://www.stb.dot.gov/decisions/readingroom.nsf/389e96bb615974918525653f005497a0/9cc76279022bab0085256a8e006bfb45?OpenDocument. *See also* Surface Transp. Bd., Class Exemption For Motor Passenger Intra-Corporate Family Transactions, Finance Docket No. 33685, (Feb. 18, 2000), *available at* http://www.stb.dot.gov/decisions/readingroom.nsf/UNID/4B9598F2477DF0828525688900662DA5/$file/30325.pdf (under section 204(a) of ICCTA, ICC precedent in effect on the date of enactment of the ICCTA continues in effect until modified or revoked in accordance with law).

139. A 1998 report from the General Accounting Office (now Government Accountability Office) appears to have introduced some confusion on this point. U.S. GENERAL ACCOUNTING OFFICE, SURFACE TRANSPORTATION: ISSUES ASSOCIATED WITH PIPELINE REGULATION BY THE SURFACE TRANSPORTATION BOARD (1998). That report indicated (with no citation to any law or reference to the long-standing declaratory orders in the *Cortez* proceeding) that CO_2 pipelines were subject to STB regulation under the Interstate Commerce Act. *Id*. at 7 (including carbon dioxide among products carried by pipelines subject to the STB's jurisdiction). The jurisdictional question was subsequently specifically examined by a Congressional Research Service report that discussed the legal precedents and noted that under present law CO2 pipelines were *not* subject to regulation by the STB. *See generally*, ADAM VANN & PAUL W. PARFOMAK, CONGRESSIONAL RESEARCH SERVICE, REGULATION OF CARBON DIOXIDE (CO_2) SEQUESTRATION PIPELINES: JURISDICTIONAL ISSUES (April 15, 2008) http://ncseonline.org/NLE/CRs/abstract.cfm?NLEid=2051 [hereinafter CRS 2008 CO_2 PIPELINE JURISDICTIONAL ANALYSIS] *discussing Cortez* rulings by the ICC and the FERC. Subsequent CRS reports on CO_2 pipelines have recognized the non-jurisdictional nature of CO_2 pipelines under current law and explored potential resulting policy implications for new CO_2 pipeline construction. *See, e.g.*, CO_2 PIPELINES: EMERGING POLICY ISSUES 2008, *supra* note 120.

ii. CO_2 Pipelines under the Natural Gas Act.

During the same general time period of early CO_2 pipeline construction, the question of jurisdiction was also presented to the FERC through a request for a declaration that the proposed interstate CO_2 pipeline would not be subject to jurisdiction under either the Natural Gas Act or the Natural Gas Policy Act of 1978. On April 6, 1979, the FERC granted the request.[140] The FERC found that a gas that was ninety-eight percent pure carbon dioxide, with traces of methane in the remaining two percent (which was not separated from the main production) was not "natural gas" within the meaning of the Natural Gas Act. It based its ruling in part on the chemical composition of the gas itself, its source and intended use in the production of oil and on the goals of the Natural Gas Act.[141] Accordingly, the FERC's order clearly held that Cortez would not become a "natural-gas company" under the Natural Gas Act by constructing or operating the proposed CO_2 pipeline. In 2006, the FERC reiterated the non-jurisdictional nature of CO_2 pipelines in the context of granting abandonment of a natural gas pipeline by sale for conversion to CO_2 transportation.[142]

b. Carriage obligations under Mineral Leasing Act of 1920.

A different type of regulatory obligation may arise in the event that a CO_2 pipeline receives a right-of-way authorization issued by the BLM to cross Federal lands subject to the Mineral Leasing Act of 1920 (MLA).[143] In *Exxon Corp. v. Lujan*,[144] the court reviewed a BLM decision to issue a right-of-way across federal land in Wyoming for a proposed CO_2 pipeline for EOR purposes under section twenty-eight of the MLA,[145] rather than under the Federal Land Policy and Management Act (FLPMA),[146] (which was the authorization that the applicant had requested). The importance of the BLM decision lay in the fact that the MLA makes a pipeline (and related facilities) that is authorized under that act a "common carrier" and expressly requires the owner or operator to transport "without discrimination" all "oil or gas" delivered to the pipeline "without regard to whether such oil or gas was produced on Federal or non-Federal lands."[147] Section twenty-eight does not mention rights of way for CO_2

140. *Cortez Pipeline Co*., 7 F.E.R.C. ¶ 61,024 (1979).

141. *Id*. at ¶ 61,042 (stating that jurisdictional "result [was] reached by considering the source of the production, the use of the production, and the actual chemical composition of the production involved, in light of the goals of the NGA").

142. *Southern Natural Gas Co*., *supra* note 26.

143. Mineral Leasing Act of 1920 (MLA), codified as amended, 30 U.S.C. § 185 (2006).

144. 970 F.2d 757 (10th Cir. 1992) [hereinafter *Lujan*].

145. 30 U.S.C. § 185 (2006).

146. 43 U.S.C. § 1761(a)(2) (2006).

147. Section 28 of the MLA provides, in relevant part, as follows:

> (a) Rights-of-way through any Federal lands may be granted by the Secretary of the Interior or appropriate agency head for pipeline purposes for the transportation of oil, natural gas, synthetic liquid or gaseous fuels, or any refined product produced therefrom to any applicant possessing the qualifications provided in section 181 of this title in accordance with the provisions of this section. . . .
>
> (r)(1) Pipelines and related facilities authorized under this section shall be constructed, operated, and maintained as common carriers.

specifically, but rather addresses rights of way for the transportation of "oil, natural gas, synthetic liquid, or gaseous fuels, or any refined product produced therefrom."[148] The applicant in *Lujan* argued that the BLM had previously issued right of way authorizations for a CO_2 pipeline under the FLPMA (which, as noted, has no comparable common carrier provision) and that the term "natural gas" in section twenty-eight of the MLA referred to hydrocarbon gases only, and did not include CO_2.[149]

The BLM disagreed and in affirming the agency, the court of appeals upheld the interpretation that for purposes of the MLA, CO_2 is "natural gas."[150] The court found that the term "natural gas" in that statute was ambiguous and that the BLM's interpretation was a permissible resolution of that ambiguity.[151] The court rejected the argument that BLM's decision was impermissibly inconsistent with the FERC's ruling in *Cortez* that CO_2 is not "natural gas" within the meaning of the Natural Gas Act, stating that the differing interpretations of the word "gas" by agencies acting under other statutes "have no bearing on the Department's interpretation of the 1914 Act or of the related Mineral Lands Leasing Act, and do not make the Department's practice internally inconsistent."[152]

The applicant in *Lujan* had also raised a policy argument to support its textual claims that may arise again in the context of future carbon regulation. The applicant asserted that a common carrier requirement would unduly burden industry's use of naturally-occurring CO_2 in EOR operations and indeed would create perverse incentives to use artificial or manufactured CO_2 that would not be subject to the MLA's common carrier provisions. The *Lujan* court, however, found that assessing the wisdom of such considerations was "more appropriately left to the agency,"[153] and rejected the argument.[154]

Summarizing the applicable federal regulatory landscape as of 2008, it seems fair to say that CO_2 pipelines are neither "common carriers" under the Interstate Commerce Act nor "natural gas companies" under the Natural Gas

> (2)(A) The owners or operators of pipelines subject to this section shall accept, convey, transport, or purchase without discrimination all oil or gas delivered to the pipeline without regard to whether such oil or gas was produced on Federal or non-Federal lands.

30 U.S.C. §§ 185(a), (r)(1), (r)(2)(A) (2006).

148. *Id*. §§ (a).

149. *Lujan*, *supra* note 144, at 760.

150. *Id*. at 763.

151. *Id*.

152. *Id*. at 762.

153. *Id*. at 763.

154. Students of the natural gas industry will immediately recognize in this ruling the potential peril of a bifurcated market developing for CO_2 sales and transportation in which operators seek to preserve a favorable regulatory status by contractually prohibiting shippers from commingling a different regulatory class of otherwise-fungible CO_2 due solely to adverse regulatory consequences that could result. *See, e.g.*, California v. Lo-Vaca Gathering Co., 379 U.S. 366 (1965) (finding that commingling of intrastate gas in interstate natural gas pipeline subjected the otherwise intrastate gas to Natural Gas Act regulation); 15 U.S.C. 3374(a) (provision of the Natural Gas Policy Act of 1978 making unenforceable certain anti-commingling contractual provisions). *See also*, James H. McGrew, American Bar Association, F.E.R.C. 16 (2003); Process Gas Consumers Group v. U.S. Dept. of Agriculture, 694 F.2d 728, 764 (D.C. Cir. 1982) (noting that Congress intended through NGPA to merge a "badly bifurcated market").

Act. They may however be "common carriers" under the MLA if: (a) they cross Federal land that is subject to that act, and (b) if the BLM issues right of way authorization under the MLA rather than the FLPMA. The operation of CO_2 pipelines remains subject of course to other generally applicable federal law.

c. Regulation under state law.

Although not generally subject to federal economic regulation (with the exceptions noted above), CO_2 pipelines *are* subject to considerable oversight at the state level and may be common carriers in some jurisdictions but private contract carriers in others. In at least one state, the operator is given a choice of regulatory regimes. Practitioners researching these issues will need to examine a particular pipeline's status under relevant state law.

There is, of course, no single definition of the term "common carrier." The term has been used in court decisions going back hundreds of years in both America and England. As put by one court, "[t]here is scarcely any field of law more ancient or more written on than that of carriers."[155] In modern times, the term has been generally used to mean a business that is required to serve all customers to the extent of its capacity at reasonable rates. The term common carrier has also been used to define instances where a carrier is in effect an insurer of goods entrusted to it for carriage (such that a common carrier was generally held to be "strictly liable" for loss of goods during transit regardless of fault while private carriers were liable only in the event a loss was caused by their negligence).

The question of how a business becomes subject to these obligations varies to some degree among different jurisdictions. Prior to the twentieth century, it was principally courts that imposed common carrier status on particular businesses (as discussed below). Over the last 100 years, legislatures have largely – but by no means entirely – supplanted the courts.

i. Common carrier status by statute.

Where a legislature has adopted a regulatory scheme for common carriers of one type or another, the question of whether a particular company is a common carrier is usually a fairly straightforward matter of either interpreting a statutory definition or reviewing the facts to see if the carrier in question comes within the terms of the statute. The states began to address CO_2 production for EOR purposes several decades ago. In several states, the legislatures enacted laws specifically designed to address and encourage CO_2-based oil production, including favorable tax treatment and mechanisms for obtaining a right of eminent domain to acquire rights of way for CO_2 pipelines.[156]

- In Texas, for example, the Texas legislature in 1991 enacted legislation which brought CO_2 and hydrogen pipelines under common carrier regulation by the Texas Railroad Commission under certain defined circumstances. Under the Texas statute, the

155. Semon v. Royal Indemnity Company, 279 F.2d 737, 739 (5th Cir. 1960).

156. Issues related to eminent domain are also implicated in the acquisition of rights to underground storage and are discussed in this context in Section III.E.

grant of eminent domain is not limited to CO_2 pipelines that are transporting for EOR purposes, but applies to any pipeline transporting CO_2. As codified, the statute declares that "[c]ommon carriers have the right and power of eminent domain"[157] and includes within the definition of common carrier a person who "owns, operates, or manages, wholly or partially, pipelines for the transportation of carbon dioxide or hydrogen in whatever form to or for the public for hire, but only if such person files with the commission a written acceptance of the provisions of this chapter expressly agreeing that, in consideration of the rights acquired, it becomes a common carrier subject to the duties and obligations conferred or imposed by [the statute]."[158] Hence, the statute effectively offers a pipeline developer an option to be either a private contract carrier or a common carrier, while offering eminent domain power to those that elect the common carrier option.

- The Mississippi CO_2 legislation dates from 1984. The Mississippi statute[159] is more limited than the Texas law in one respect, as it limits the availability of eminent domain for the construction of CO_2 pipelines to those that are "for use in connection with secondary or tertiary recovery projects located within the state of Mississippi for the enhanced recovery of liquid or gaseous hydrocarbons."[160] In addition to providing for eminent domain, the legislation also: granted a tax exemption from ad valorem taxes (except school taxes) for CO_2-based pipelines and related equipment that was used "in connection with an enhanced oil recovery project in the state of Mississippi"[161]; eliminated severance taxes on certain CO_2 used for enhanced oil recovery[162]; and reduced the severance tax applicable to oil recovered by use of CO_2 from six to three percent.[163]
- The Louisiana Statute allows the expropriation (which is to say condemnation) of property for "the piping or marketing of carbon dioxide for use in connection with a secondary or tertiary recovery project for the enhanced recovery of liquid or gaseous

157. Tex. Natural Ressources Code Ann. § 111.019(a). For a review of Texas law governing exercise of eminent domain powers by common carrier pipelines generally, *see generally* Laura Hanley, *Judicial Battles Between Pipeline Companies And Landowners: It's Not Necessarily Who Wins, But By How Much*, 37 HOUSTON L. REV. 125 (2000).

158. Tex. Natural Resources Code Ann § 111.002(6).

159. Miss. Code. Ann. § 11-27-47 (1984). *See also* MISS. OIL AND GAS BOARD, STATUTES, RULES OF PROCEDURE, STATEWIDE RULES AND REGULATIONS 5, 45 (June 30, 2008), http://www.ogb.state.ms.us/docs/RuleBook2008.pdf (*citing* Miss. Code Ann. §§ 53-1-3, 53-3-159). While the rules of the Mississippi Oil and Gas Board in its Rulebook define the term "gas" as including carbon dioxide, the only rules on eminent domain relate to construction of underground storage facilities, not transportation pipelines. *Id*.

160. MISS. CODE. ANN. § 11-27-47 (1984).

161. *Id*. § 27-31-102.

162. *Id*. § 27-25-703.

163. *Id*. § 27-25-503. *See generally* Shell Western E & P, Inc. v. Board of Supervisors of Pike County, 624 So. 2d 68, 70-71 (Miss. 1993) (summary of 1983 legislation).

hydrocarbons approved by the commissioner of conservation."[164] The exercise of that power is conditioned, however, on approval of the enhanced recovery project by the commissioner of conservation and issuance of a certificate of public convenience and necessity for the pipeline.[165] In contrast to the Mississippi statute, the Louisiana law applies even if the CO_2 transportation for underground injection is in connection with projects in other states or jurisdictions as well as Louisiana.[166] In that case, "the commissioner's approval shall consist of confirmation that the applicable regulatory authority of that state or jurisdiction has approved or authorized the injection of carbon dioxide in association with such project."[167]

Other states with significant CO_2 operations also have provisions for pipeline right of way acquisition and define the carriage status of CO_2 pipelines.[168]

ii. Common carrier status and eminent domain under the common law.

Before statutes were commonly adopted – but continuing to the present day – courts have on occasion found businesses to be common carriers under the common law. With regard to how a business becomes subject to carriage obligations, the traditional view holds that a carrier ceases to be a "private" or "contract" carrier and becomes a *common* carrier when it "holds itself out" to the public as a common carrier, as by posting rates and offering to carry for all.[169]

The Louisiana Court of Appeals has quoted, with approval, the traditional view, as stated in a legal encyclopedia:

> A private carrier is one who, without making it a vocation, or holding himself out to the public as ready to act for all who desire his services, undertakes, by special agreement in a particular instance only, to transport property or persons from one place to another either gratuitously or for hire. Private carriers are distinguished from common carriers in respect of (1) the obligation to carry and (2) the liability for loss or injury. Private carriers do not undertake to carry for all persons indiscriminately but transport only for those with whom they seem fit to contract, and are liable for only such loss or injury as results from a failure to exercise ordinary care, whereas common carriers undertake to carry any and all members of

164. LA. REV. STAT. § 19:2(10) (2007).

165. *Id*. § 30:4(c)(17)(a) (2007). The Commissioner is also tasked "[t]o regulate the construction design and operation of pipelines transmitting carbon dioxide to serve secondary and tertiary recovery projects for increasing the ultimate recovery of oil or gas, including the issuance of certificates of public convenience and necessity for pipelines serving such projects approved hereunder." *Id.*

166. *Id*.

167. *Id*. at § (b).

168. For a review of state legislative action governing CCS as of early 2008 *see generally State CCS Progress*, *supra* note 36 (discussing in particular Wyoming, New Mexico, California, North Dakota, Texas, and Kansas).

169. A contrasting line of cases referenced below provide instances in which courts have imposed common carrier status because of the nature of the service it provides, or because it enjoys an important publicly-granted benefit such as a legal monopoly, a franchise, or a right of eminent domain.

> the public who desire such service, and are liable as insurers for the loss or injury of property[170]

Similarly (although applying a federal statute), a Federal District Court in New Orleans endorsed the "holding out" standard as one of the "two main attributes" that characterize a common carrier:

> First, it carries persons and goods belonging to others for their benefit and for hire. Second, it must hold itself out as ready to engage to carry for persons generally and as willing to engage in the transportation of goods or persons for hire as a public employment. *Those who do not hold themselves out as willing to serve the public indiscriminately are not common carriers.* The distinctive characteristic of a common carrier is that it undertakes to carry for all people indifferently.[171]

In Texas as well, in a decision that pre-dates the legislation governing CO_2 pipelines, the courts have applied the "holding out" standard:

> Whether the business conducted by a pipe line company is actually that of a common carrier is a question of fact. 4 Summers, OIL AND GAS 321, § 751. If, in fact, the line is available to all producers seeking its services – that is, to the public generally – it is a common carrier. Otherwise it is a private carrier.[172]

The same view has been adopted under some federal law. For example, in *National Association of Regulatory Utility Commissioners v. Federal Communication Commission, (NARUC I)*, the court construed federal communications law where the federal statute regulated communications "common carriers" but did not define what they were.[173] The D. C. Circuit there strongly endorsed the "holding out" test – that the common carrier is one who undertakes to carry for all people indifferently – finding it "essential" to the "quasi-public character implicit in the common carrier concept."[174] The court relied *inter* alia on the above-cited cases applying Mississippi and Louisiana law.[175] It reiterated its holding a month later in even stronger terms in "*NARUC II*":

> Nor is it essential that there be a statutory or other legal commandment to serve indiscriminately; it is the practice of such indifferent service that confers common carrier status. That is to say, a carrier will not be a common carrier where its

170. Portier v. Thrift Way Pharmacy, 476 So. 2d 1132 (La.Ct.App.1985) *quoting* 13 Am. Jur. 2d Carriers, § 8, 565.

171. Ciaccio v. New Orleans Pub. Belt RR, 285 F. Supp. 373, 375 (E.D. La. 1968) (emphasis added). *See also* Home Insurance Co. v. Riddell, 252 F.2d 1, 4 (5th Cir. 1958) (emphasis added). While the Riddell court was a federal appeals court, it was applying Mississippi law. Note that federal courts apply *federal* law when deciding federal cases, but *state* law (of the state in which they sit) when they decide cases that are before them only because the litigants are from different states (known as "diversity" jurisdiction). What this means is that while federal decisions applying federal law may be consulted by a state court, the state court is normally not bound to apply the federal decision in determining state law. Further, while federal cases applying state law in diversity cases are certainly relevant, it is ultimately only a state court that can definitively declare state law in the event of a conflict on some particular point as to the applicable rule of law in the state. Because common carriage is a matter so weighted by history and basic questions of state control of business, federal cases on this topic must be handled with some care as possible precedents.

172. China-Nome Gas Co. v. Riddle, 541 S.W.2d 905, 908 n.5 (Tex.Civ.App. 1976).

173. National Ass'n of Regulatory Utility Comm'rs v. FCC, 525 F.2d 630, 641 n. 51-52 (D.C. Cir. 1976) (footnote omitted) [hereinafter *NARUC*].

174. *Id*.

175. *Id*. at 641 n.57-58 *citing Riddell, Ciaccio, & Semon v. Royal Indemnity Co.*, 279 F.2d 737 (5th Cir. 1960).

> practice is to make individualized decisions in particular cases whether and on what terms to serve.[176]

Many other cases are to the same effect,[177] and indeed, prior to the New Deal in the 1930s, there was even a line of US Supreme Court cases that held that an existing private contract carrier could not be converted into a common carrier "by mere legislative command". [178]

There is a contrasting line of cases that looks to the nature of the service provided, rather than to whether the provider holds itself out to serve the public generally. The Federal Communications Commission produced a virtual monograph on the topic in 1981 (in an apparent effort to respond to the D.C. Circuit's opinions in *NARUC I* and *NARUC II*).[179] Hence the grant of eminent domain power to a business has certainly been viewed at times as justifying the

176. *Id*. at 608-609 n. 33-34 (internal citations omitted).

177. *See, e.g.*, Woolsey v. National Transp. Safety Bd., 993 F.2d 516 (5th Cir. 1993) (crucial determination in assessing the status of a carrier is whether the carrier has held itself out to the public or to a definable segment of the public as being willing to transport for hire, indiscriminately); U.S. v. Stephen Bros. Line, 384 F.2d 118, 122-123 (5th Cir. 1967) (salient characteristic of a common carrier is that he must be engaged in the business of carrying goods for others as a public employment, and must hold himself out as ready to engage in the transportation of goods for persons generally and holds himself out as ready to engage in the transportation of goods for hire as a public employment and undertakes to carry for all persons indifferently and to state it conversely, those who do not hold themselves out as willing to serve the public indiscriminately, are not common carriers); Semon v. Royal Indemnity Co., 279 F.2d 737 (5th Cir. 1960) *citing* Home Insurance Co. v. Riddell, 252 F.2d 1, 2 (5th Cir. 1958), for principle that the "critical point" is that distinction in status "comes about from the nature of the holding out" and that "the distinctive characteristic of a common carrier is that he undertakes to carry for all people indifferently"; State ex rel. Utilities Comm'n v. Gulf-Atlantic Towing Corp., 110 S.E.2d 886, 889 n. 6 (N.C. 1959) (definition of a common carrier at common law "seems to be clearly settled" in that a common carrier is "one who holds himself out to the public as engaged in the public business of transporting persons or property for others for compensation from place to place, offering his services to such of the public generally as choose to employ him and pay his charges"); and Mt. Tom Motor Line, Inc. v. McKesson & Robbins, Inc., 89 N.E.2d 3, 5 (Mass. 1949) (a common carrier is "one who holds himself out as furnishing transportation to any and all members of the public who desire such service in so far as his facilities enable him to perform the service, while a contract carrier does not furnish transportation indiscriminately but furnishes it only to those with whom he sees fit to contract"). For aviation cases, *see also*: Las Vegas Hacienda, Inc. v. Civil Aeronautics Bd., 298 F.2d 430 (9th Cir. 1962); East Coast Flying Serv. Enforcement Proceeding, 46 C.A.B. 640 (1967); M & R Inv. Co., Inc. v. Civil Aeronautics Bd., 308 F.2d 49 (9th Cir.1962); Arrow Aviation, Inc. v. Moore, 266 F.2d 488 (8th Cir. 1959); Southeastern Aviation, Inc. Enforcement Proceeding, 32 C.A.B. 1281 (1961); Consolidated Flower Shipments, Inc., 16 C.A.B. 804 (1953); and, Intercontinental Enforcement Proceeding, 41 C.A.B. 583 (1965).

178. Washington *ex rel.* Stimson Lumber Co. v. Kuykendall, 275 U.S. 207 (1927). It is established that, consistently with the due process clause of the Fourteenth Amendment, a private carrier cannot be converted into a common carrier by mere legislative command. *Id. citing* Frost Trucking Co. v. R. R. Comm'n, 271 U.S. 583 (1926) and Michigan Pub. Utilities Comm'n v. Duke, 266 U.S. 570 (1924). In light of the multiple regulatory interventions in transportation industries over the course of the 20th century, these cases may be primarily of historical interest.

179. App. B, Definition of Common Carrier Common Law Background, In the matter of policy and rules concerning rates for competitive common carrier services and facilities authorizations therefore, 46 Fed. Reg. 10,924, 10,955 (1981) [hereinafter FCC Appendix B]. The FCC reviewed cases beginning with a ferryman in 1348 and traced six centuries of common carriage law, repeating the well-known and often-quoted English legal commentary of Lord Hale addressing seaports from the 1600s as businesses that are "affected with a public interest." *Id.* citing Lord Hale, *De Portibus Maris*, 1 HARGROVE LAW TRACTS 77-78 (1787).

imposition of common carrier duties.[180] As argued by one turn-of-the-twentieth-century legal scholar:

> [T]he potential general usefulness of an undertaking to the members of a community justifies the grant of the power of eminent domain for the furtherance of the undertaking, and the acceptance of such a grant carries with it the duty to use such powers reasonably and impartially for the benefit of all applicants.[181]

In view of the extensive history of contract and common carriage, practitioners researching CO_2 pipeline carriage issues will want to review carefully the applicable state statutes and judicial and regulatory precedents.

3. Role of tax qualification as master limited partnerships for CO_2 pipelines.

As is the case with oil and natural gas pipelines, pipelines carrying naturally-occurring CO_2 for EOR purposes today are frequently structured as master limited partnerships in order to qualify for single taxation of their income under section 7704 of the Internal Revenue Code (IRC).[182] Under section 7704, a partnership may qualify for exemption from taxation as a corporation if ninety percent, or more, of its gross income is "qualifying income" as defined in subsection (d). Of relevance here, paragraph (d)(1)(E) of section 7704 provides qualifying status for income and gains from any "mineral or natural resource."[183] The term "mineral or natural resource" is further defined (with an exception not relevant here)[184] as a product qualifying for percentage depletion under section 613 of the IRC. Hence, when the Internal Revenue Service (IRS) ruled in 1982 that CO_2 produced from a well is subject to percentage depletion as a mineral,[185]

180. Western Union Telegraph Co. v. Call Publishing Co. 181 U.S. 92, 100 (1901). The court there stated that common carriers are performing a public service and are "endowed by the state with some of its sovereign powers, such as the right of eminent domain." *Id*. As a result, reasoned the court "all individuals have equal rights both in respect to service and charges." *Id*. The court found the public service obligations to exist under federal law notwithstanding the absence of any statutory regulation.

181. Charles K. Burdick, *The Origin of the Peculiar Duties of Public Service Companies*, 11 COLUM. L. REV. 514 at 629 (1911) (*as quoted in* James B. Speta, *A Common Carrier Approach to Internet Interconnection*, 54 FED. COMM. L.J. 225 (2002)). The above discussion is a bare dribble from a century-wide river of law review articles, cases, and entire books devoted to common carriage. For an introduction to the literature, *see, e.g.,* LARS GORTON, THE CONCEPT OF THE COMMON CARRIER IN ANGLO-AMERICAN LAW (Läromedelafërl 1971) (1971); Bruce Wyman, *The Law of the Public Callings as a Solution of the Trust Problem,* 17 HARV. L. REV. 156 (1904); Peter K. Pitsch & Arthur W. Bresnahan, *Common Carrier Regulation of Telecommunications Contracts and the Private Carrier Alternative*, 48 FED. COM. L. J. 447 (1996).

182. 26 U.S.C. § 7704 (2006).

183. Prior to a recent amendment in 2008 discussed below, the term qualifying income was defined to includes: "income and gains derived from the exploration, development, mining or production, processing, refining, transportation (including pipelines transporting gas, oil, or products thereof), or the marketing of any mineral or natural resource (including fertilizer, geothermal energy, and timber)." 26 U.S.C. § 7704(d)(1)(E). As noted below, the law was amended by the Energy Improvement and Extension Act of 2008, Pub. L. 110-343, div. B [hereafter the "Energy Improvement and Extension Act"], section 116 of which inserted the term "industrial source carbon dioxide" prior to the phrase "and timber".

184. The full definition of "mineral or natural resource" is "any product of a character with respect to which a deduction for depletion is allowable under section 611; except that such term shall not include any product described in subparagraph (A) or (B) of section 613(b)(7)." 26 U.S.C. § 613(G) (2006). The referenced exclusions in subparagraphs (A) and (B) exclude involve "soil, sod, dirt, turf, water, or mosses" and "minerals from sea water, the air, or similar inexhaustible sources." *Id*. §§ (b)(7)(A)-(B).

185. Rev. Ruling 82-17, 1982-1 C.B. 95. The ruling also found that CO_2 is not a "gas" for purposes of several other sections of the Code that refer to "oil or gas," finding that in those references, the Congress was

it effectively confirmed the exemption from taxation as a corporation for CO_2 pipelines. The same result was reached seven years later in Revenue Ruling 89-126.[186]

The question had been raised in congressional hearings on CO_2 pipeline issues, however, as to whether pipeline transportation revenue derived from *anthropogenic* CO_2 produced from an industrial source would continue to meet these statutory requirements.[187] This uncertainty suggested that existing CO_2 pipelines structured as master limited partnerships (MLP) might not transport anthropogenic CO_2, or would do so only at significantly higher tax costs than those incurred by other pipelines. Hence, failure to resolve this tax issue could have induced operators of MLP-owned CO_2 pipelines to prohibit the commingling of material volumes of anthropogenic CO_2 in pipelines already carrying naturally-occurring sources of CO_2. This situation would have been the converse of the one discussed above in which, anthropogenic sources of CO_2 may have a preferred regulatory status under the MLA that may lead operators of pipelines carrying anthropogenic CO_2 to prohibit the commingling of natural-sourced CO_2,tending to create a regulatory-induced bifurcation of CO_2 pipelines that could discourage the development of an integrated pipeline grid.

The issued was addressed by the Congress, however, in October of 2008 by enactment of the above-cited Energy Improvement and Extension Act, which (among a number of provisions affecting carbon capture and storage) includes a provision specifically including "industrial source carbon dioxide" in above-quoted definition of "qualifying income." The new provision thus appears to avoid the risk of a tax-induced bifurcation evolving between CO2 pipelines carrying naturally-occurring CO2 and those carrying anthropogenic CO2 captured from industrial facilities or power plants that could have discouraged the integration of anthropogenic CO2 sources with existing pipeline infrastructure.

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referring to hydrocarbons. *Id*. Thus, while CO_2 does qualify for percentage depletions as a mineral or other natural resource, it does not qualify for certain intangible drilling expenses that are allowed for "oil and gas" under other provisions of the Code. *Id*. The ruling states in relevant part:

> Although in the physical sense CO_2 is a gas, it is not the gas referred to in the term 'oil and gas wells' in sections 263(c), 611, 613 and 613A of the Code. The gas referred to in these sections is hydrocarbon gas. The CO_2 is an exhaustible natural deposit but is not specifically referred to in any of the categories named in paragraphs 613(b)(1) through (6). Thus, it falls in the category of all other mineral described in section 613(b)(7) and is eligible for percentage depletion at the rate of 14 percent. Section 613A does not deny percentage depletion for CO_2.

Id.

186. Rev. Ruling 89-126, 1989-2 C.B. 99 ("CO_2 reserves in the ground are an exhaustible natural resource not only under section 613(b)(7) of the Code, but also under section 616. Furthermore, because wells drilled for the production of CO_2 are not oil and gas wells, the costs of CO_2 wells are not excluded from the application of section 616.") (*citing* 26 U.S.C. §§ 613(b)(7), 616 (2006)).

187. The Policy Aspects of Carbon Capture, Transportation, and Sequestration and Related Bills, S. 2323 and S. 2144: Hearing Before the Senate Comm. on Energy and Natural Resources, 110th Cong., 2d Sess. (Jan. 31, 2008), at 59, (statement of Ronald T. Evans, Senior Vice President, Reservoir Engineering, Denbury Resources, Inc.). Legislation to amend section 7704 to include "industrial source carbon dioxide" in the definition of "qualifying income" for partnerships was introduced in the 110th Congress but was not enacted. *Id*.

4. Design and operational requirements of "EOR pipelines," "CCS pipelines" and "hybrid pipelines."

It is also important to consider the operational imperatives of a CO_2 pipeline built to support EOR oil production projects and the issues regarding appropriate operational terms and conditions. As will be seen these differ substantially from the operational requirements likely to be required of CO_2 pipelines used solely for CCS purposes. To understand these issues, it is helpful to review the operational dynamics of a CO_2 pipeline used for EOR purposes, to compare those dynamics to the requirements of a hypothetical, or "model," CO_2 pipeline that is designed exclusively for CCS purposes – and then explore the more pragmatic case; in which, a CO_2 pipeline originally built for EOR could gradually accommodate industrially-captured CO_2 into its operations and transition over a period of years – or even decades – from incidental storage from EOR operations toward the CCS model. We will refer to these models as an "EOR pipeline," a "CCS pipeline," and a "Hybrid pipeline," respectively. As discussed below, there are fundamental differences between an the EOR pipeline and a CCS pipeline and indeed, in certain respects operational requirements pull in directly opposite directions, while a "hybrid" pipelines will have to somehow compromise these differences. These differences will need to be recognized and taken into account in any successful regulatory system for CCS pipelines.

a. The EOR pipeline model.

As suggested by the above discussion, an EOR pipeline is focused on serving *downstream* interests of EOR production. For example, the sizing of pipeline capacity, the planning for CO_2 supply years into the future, as well as daily operations, are all integrated in downstream oil production operations. Indeed, operations of an EOR pipeline will be almost entirely subordinate to the oil production operations it serves, since that is its sole economic purpose and the CO_2 is an essential factor of production, just like assuring adequate supplies of drilling mud, production tubing, or fresh water during drilling operations. A disruption of the CO_2 supply will undermine the success of the EOR production operations. Thus, where the CO_2 pipeline is operated by the producer of the oil, it becomes in effect an integral part of the oil production operations and is in essence an extension of the production area facilities. It might even be termed a "field extension line" – the mirror image homologue to a "plant extension line" where a natural gas pipeline serves a single downstream industrial user.

Another key characteristic of an EOR pipeline is that it is sized and operated to transport and inject the *least* amount of CO_2 needed to extract the *greatest* amount of oil and to re-cycle and reuse as much of the injected CO_2 as possible for the intended EOR projects. A substantial portion of the initially injected CO_2 in one oil field can be brought back to the surface as part of the oil production stream, separated (or re-captured) from the oil and recycled to the CO_2 pipeline system for re-injection either in the initial field or in a second field where the injection, re-capture and recycle process will be repeated.

In terms of geographic location and design, EOR pipelines run from CO_2 sources – at present a few large reserves of naturally-occurring CO_2 and a very limited number of anthropogenic sources to regionally-located oil producing fields. Because of the scarcity of CO_2 supply and the need to obtain the greatest value from the available supply, CO_2 operators will typically try to design a CO_2 pipeline in phases, with future extensions planned (to the extent possible) in a chronological developmental sequence, leading from the currently produced oil field to future prospects. Thus, a CO_2 project development requires years of advanced planning, construction and injection of CO_2 before an operator actually realizes any increase in oil production.

b. The CCS pipeline model.

A CCS pipeline for removing captured CO_2 from one or more power plants for permanent geologic storage is, in certain respects, the polar opposite of the EOR pipeline. It will necessarily be operationally subordinate to the generation of electricity and the requirements for reliable operation of the power grid into which the power plant delivers the power. Hence, its focus is *upstream* – on the source of CO_2 supply at the electricity generating facility. The sizing and location of CCS pipelines will be driven principally by the operational requirements of generating electricity, since the ability to continuously remove CO_2 will, under a regime of carbon regulation, be an essential component of meeting the air quality or other regulatory permit for operating such plants. Presumably under any system of carbon emission regulation, a generating facility's inability to arrange for removal all of its CO_2 emissions will result in an economic penalty. Either the plant must purchase emissions allowances at a higher cost, pay a penalty, or, ultimately, shut down, requiring the dispatch of a higher-cost generating unit.[188] A developer may be able to reduce the risk of such adverse consequences by ensuring adequate take-away capacity of the CCS pipeline. But, of course, this could produce a larger, but not fully utilized, pipeline that will result in higher unit costs for transportation. In sum, the developer will try to optimize pipeline capacity and planned operations within these and similar constraints. It may be that developers will tend to opt for vertical integration in a case like this, with the pipeline owned by the dominant power plants which it was originally constructed to serve.[189] However, the competing constraints are managed, ultimately, the pipeline must serve the interest of the power plants for which it is built, for otherwise it has no economic function.

Similarly, an operational problem downstream of the power plant – for example, an accidental line break or a problem with an injection well that interrupts CO_2 injections – could force an unscheduled outage of the power plant. This in turn could require the operator of the transmission grid to reschedule generation activities and could be extremely expensive for the power generator in terms of lost sales. As a result, the likelihood of interruptions in the CO_2 pipeline and injection operations become a factor that must be taken into account in the reliability calculations of the power grid. In sum, instead of a "field extension line" in the case of an EOR pipeline, a CCS pipeline will tend to

188. This assumes economic dispatch of the generating units absent the CO_2 constraint.

189. Vertical integration is one way for businesses to address difficult cost allocation or operational priority requirements by contract.

become the functional equivalent of a lengthy horizontal exhaust stack at the generating facility.

And of course, contrary to the case of the EOR pipeline that strives to move the minimal amount of CO_2 needed for EOR operations and to recycle and reuse as much as possible, the CCS pipeline will strive to move the *maximum* amount of CO_2 that can be removed from the atmosphere and geologically stored and will certainly not wish to take any CO_2 out of a storage site for recycling elsewhere.

c. The "hybrid pipeline."

It is likely that in many instances initial CO_2 pipelines carrying anthropogenic CO_2 from electricity generating facilities will seek to make use of the existing network of CO_2 pipelines that have been built strictly for EOR purposes.[190] The Off-Take Agreements between the anthropogenic CO_2 supplier and the EOR pipeline operator will have to take these competing considerations at each end of the pipeline into account and devise operational terms and conditions that allow the transactions to proceed. From a *contractual* standpoint, risks and costs are allocated among the parties in a way that meets business objectives. For example, due to the uncertainty of potential new carbon regulation regimes, one oil and gas operator has included in its draft form Off-Take Agreement an "economic stabilization" provision much along the lines utilized in international contracts where the vagaries of currency exchange rates and tax legislation changes can cause havoc over the course of long-term contract. The clause basically seeks to preserve "prior economic parity" for both parties.[191]

From a potential *regulatory* standpoint, however – in light of proposals to create an overall federal regulatory regime for CO_2 pipelines serving for CCS purposes – it is extremely important for any regulatory system devised to cover CO_2 pipelines to recognize these completely opposite dominant needs of EOR pipelines and CCS pipelines. Most logically, it suggests that any new legislative

190. This phenomenon is said to be likely because to some degree it has already begun, as evidenced by the announcements above (*supra* note 29) of purchases of CO_2 from industrial facilities for integration into a CO_2 supply portfolio for EOR purposes. Press Release, Denbury Resources, Inc., Denbury Signs Agreement to Purchase Additional Manufactured CO_2 (June 25, 2007), http://www.secinfo.com/dsvrp.uDX3.d.htm.

191. The text of an "Economic Stabilization Agreement" provision developed by one of the authors (Ms. Moore) and currently used in a number of current CO2 Offtake agreements provides as follows:

> Taking into consideration that CO_2 sequestration is a developing area of the law, including the applicability of Emission Reduction Carbon Credits (ERCCs) and the availability of geologic reservoirs for CO_2 storage, the parties hereto agree that should any legislation, rule or regulation of a Governmental Authority take effect after the Effective Date of this Agreement, the impact of which will be a material adverse economic impact to either party hereto, both Owner and Offtaker shall make all commercially reasonable efforts within a reasonable time thereinafter to amend this Agreement so that the prior economic parity of each of the parties is restored while retaining the intent of the parties to perform under this Agreement. Written notice by one party to the other of the material adverse impact of the legislation, rule or regulation shall also contain a proposal for achieving the prior status quo of the parties.

The term "Governmental Authority" is defined in the definitional section of those contracts and means any federal, state, municipal or other legislative authority, governmental department, commission, board, bureau, agency or instrumentality. *Id*.

scheme for CO_2 pipelines should either "grandfather," or exempt, EOR pipelines entirely and apply only to newly converted or constructed CO_2 pipelines that are to be used for CCS purposes. Absent such an exemption, or grandfathering, any tariff-based regulatory model for CO_2 pipelines (for example, based on an approach equivalent to current natural gas pipeline regulation) would need to recognize that the operational terms and conditions of an EOR pipeline must accord operational priority to serving oil field production operations, while the terms and conditions of a CCS pipeline would presumably and accord priority instead to the equally valuable dictates of reliable grid operations and least-cost electricity generation. Absent regulatory flexibility for pipelines seeking to accommodate the introduction of anthropogenic sources of CO_2 into EOR pipelines, operators may feel compelled to preclude commingling of power plant CO_2 if it will risk interfering with operations required for economic oil production.

In sum, the open-access model developed by the FERC for natural gas pipelines since its path-breaking orders beginning in 1985[192] – based on a pre-existing complex pipeline grid serving thousands of natural gas producers and thousands of wholesale and large end use customers – is highly unlikely to be a fruitful model for developing a regulatory scheme for CCS pipelines, at least in the initial stages of infrastructure development.

D. EPA and state regulation of CO_2 injection wells

1. Overview of UIC program and experience with CO_2 injection wells.

Under the Safe Drinking Water Act of 1974,[193] the EPA has developed an UIC program governing the underground injection of fluids, including CO_2. As the basic operation of the UIC program has been addressed elsewhere, (including in a recent article in this Journal),[194] we focus here solely on the applicability of the UIC program to CO_2 injections and incidental storage in the context of EOR operations.

The EPA categorizes injection wells under the UIC under five different well classes. Nearly all of the many thousand CO_2 injection wells that have been permitted by the state agencies under the UIC for EOR operations have been

192. Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 436, 50 FR 42408 (Oct. 18, 1985), FERC Stats. & Regs. [Regulations Preambles 1982-1985] ¶ 30,665 (1985), vacated and remanded, Associated Gas Distributors v. FERC, 824 F.2d 981 (D.C. Cir. 1987), readopted on an interim basis, Order No. 500, 52 FR 30334 (Aug. 14, 1987), FERC Stats. & Regs. [Regulations Preambles, 1986-1990] ¶ 30,761 (1987), remanded, American Gas Association v. FERC, 888 F.2d 136 (D.C. Cir. 1989), readopted, Order No. 500-H, 54 FR 52344 (Dec. 21, 1989), FERC Stats. & Regs. [Regulations Preambles 1986-1990] ¶ 30,867 (1989), reh'g granted in part and denied in part, Order No. 500-I, 55 FR 6605 (Feb. 26, 1990), FERC Stats. & Regs. [Regulations Preambles 1986-1990] ¶ 30,880 (1990), aff'd in part and remanded in part, American Gas Association v. FERC, 912 F.2d 1496 (D.C. Cir. 1990).

193. 42 U.S.C. § 300(f) (2008).

194. *J. Moore*, *supra* note 61. *See also* Elizabeth J. Wilson and David Gerard, CARBON CAPTURE AND SEQUESTRATION: INTEGRATING TECHNOLOGY, MONITORING AND REGULATION (Blackwell Publishing 2007). For perhaps the most detailed review of UIC regulations as they might relate to CO2 injections for non-EOR operations, *see also* Mark Anthony de Figueiredo, The Liability of Carbon Dioxide Storage (Jan. 12, 2007) (unpublished Ph.D. dissertation, Mass. Inst. of Tech.), http://esd.mit.edu/people/dissertations/defigueiredo_mark.pdf.

classified as "Class II" wells.[195] Most of these wells are located in the Permian Basin (in Texas, but also in New Mexico), but the remainder are spread over eight other states (principally Wyoming, Oklahoma, Colorado, and Mississippi).[196] The Class II permitting rules that govern these wells[197] do not differentiate based on the source of the fluid to be injected (*i.e.* whether the CO_2 is naturally-occurring or anthropogenic). Of particular relevance here, however, the regulations limit fluid injections to those used for enhanced recovery of oil or gas, such that an injection well operating under a Class II permit may not be used to continue to inject CO_2 once EOR operations have come to an end. Hence while the existing UIC Class II permits allow for the *incidental* storage of the CO_2 that occurs as a natural part of EOR operations, they do not authorize *incremental* storage of CO_2 that might otherwise continue following completion of EOR operations.

Under the Safe Drinking Water Act and the UIC program, individual state governments (as well as territories and Indian tribes) may qualify to exercise primary responsibility in implementing the EPA rules.[198] By qualifying for what is commonly termed "primacy status" for one or more well classes, the state, territorial or tribal authority serves in effect as a "co-regulator" and the primary permitting agency in implementing the permitting program.

All of the states in which significant EOR operations are underway have qualified for primacy status for Class II CO_2 injection wells.[199] In most cases, it is the state oil and gas commission (or similar agency) that is responsible at each state for implementing the UIC Program for these wells. In contrast, the EPA Regions have issued just two permits for CO_2 EOR wells (one of which was an area permit for the Navaho Nation that may cover multiple wells).[200] This means that the everyday oversight responsibility and staff expertise in dealing with underground injection of CO_2 resides at present in the states, not with the EPA. This in turn suggests that federal-state relations and allocation of institutional responsibilities within the states may be among the major issues that must be addressed in adapting the current rules so that they can accommodate non-EOR injections.

195. GWPC CO2 Well Survey, *supra* note 6. Only a handful of CO2 injection wells were reported as Class V experimental wells. *Id*.

196. The other significant CO2-based EOR states are New Mexico (178 wells) and Utah (130 wells). Michigan, Kansas and Louisiana reported just a handful of CO2 (13 wells reported among all three).

197. 40 C.F.R. Pt. 146, Subpart C (§§ 146.21 to 146.26). The EPA's rules define Class II injection wells *inter alia* to include wells which inject fluids "[f]or enhanced recovery of oil or natural gas." 40 C.F.R. § 144.6 (b) (2). More general information on Class II wells is at http://www.epa.gov/OGWDW/uic/wells_class2.html (last visited Aug. 29, 2008).

198. 42 U.S.C. 300h-1. For states without programs, or whose programs have been disapproved, EPA is required to prescribe federal UIC requirements under what is known as "direct implementation." *See* 42 U.S.C. 300h-1(c). *See also, HRI Inc. v. Envtl. Protection Agency*, 198 F.3d 1224 (10th Cir. 2000).

199. The EPA posts a list of primacy status by well class on its website. For the current list, *see* http://www.epa.gov/safewater/uic/pdfs/Delegation%20status.pdf (last visited Oct. 6, 2008).

200. GWPC CO2 Well Survey, *supra* note 6, at 66, 74.

2. The EPA's Class VI rulemaking proceeding.

As early as 2005, the EPA began conducting workshops on CO_2 injections for permanent underground storage. In October of 2007, the EPA announced its intention to develop regulations that the agency hopes would establish a clear path for the geologic storage of CO_2.[201] A series of public workshops was held over the course of the next several months, including technical workshops on issues of measuring, monitoring and verifying CO_2 storage injections.[202] One of the issues raised in the EPA public consultative process was the possible impact of a new CO_2 injection rule might have on the thousands of existing CO_2 injection wells used for EOR purposes. Among many other issues, the public workshops highlighted the differing characteristics of the various possible storage formations (*e.g.*, the presence of relatively better defined formation boundaries in the case of oil and gas producing reservoirs as compared to saline aquifers.)[203]

In July of 2008, the EPA issued a lengthy rulemaking notice (together with various technical supporting documents) proposing to revise the UIC program by establishing a new well classification – Class VI – for what the EPA terms "geologic sequestration" or "GS" wells (Class VI Proposed Rulemaking).[204] The proposed rule defines "geologic sequestration" as "the long-term containment of a gaseous, liquid or supercritical carbon dioxide stream in subsurface geologic formations" and does "not apply to its capture or transport."[205] In general, the proposed rule would build on the existing permit and operating conditions that apply to the other injection well classes under the existing UIC program. Thus, the proposed rule details the contents of the proposed Class VI permit application and sets minimum criteria for selecting long-term storage sites (including determining the area of review and prior corrective action such as taking action on wells in the area of review to prevent movement of fluid into or between underground sources of drinking water). The proposal would establish minimum requirements for well construction (including casing and cementing), pre-injection logging and testing, and injection operations. The proposed rules are analogous to existing UIC requirements, but generally more restrictive. For example, while the existing rules that apply to Class II wells generally prohibit the use of injection pressure that could "initiate new fractures or propagate existing fractures in the confining zone"[206] adjacent to the drinking water sources, the proposed rule for Class VI wells would adopt a more conservative

201. Press Release, EPA, EPA To Develop Regulations for Geologic Sequestration of Carbon Dioxide (Oct. 11, 2007) http://yosemite.epa.gov/opa/admpress.nsf.

202. The entry portal to EPA's geological sequestration program activities is http://www.epa.gov/safewater/uic/wells_sequestration.html (last visited Oct. 6, 2008). The site has detailed summaries of public comments made at several of the workshops and the EPA staff's presentations.

203. Detailed summaries of public consultation workshops are available at http://www.epa.gov/safewater/uic/wells_sequestration.html#stakeholderworkshops (last visited Oct. 6, 2008).

204. Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration (GS) Wells, 73 Fed. Reg. 43492 (proposed July 25, 2008) [hereinafter Class VI Proposed Rulemaking]. The proposed rule and the technical supporting documents are available on the website at http://www.epa.gov/ogwdw000/uic/wells_sequestration.html#regdevelopment (last visited Sept. 2, 2008).

205. *Id*. § 146.81(d).

206. *Id*. at tbl. VII-1.

rule by prohibiting injection pressures in excess of ninety percent of the fracture pressure of the injection zone.[207] Ongoing testing and monitoring requirements are proposed to ensure mechanical integrity of the injection well as well as various reports to be filed with the entity administering the UIC program in the relevant jurisdiction.[208] The topics addressed in the proposed rule are summarized in Figure 3 below.

FIGURE 3

Proposed requirements	**Proposed rule**
Contents of the Class VI permit application;	Section 146.82
Criteria for selecting storage site, determining area of review and required prior corrective action (e.g. taking action on wells in the area of review to prevent movement of fluid into or between underground sources of drinking water, etc.)	Sections 146.83 to 146.84
Well construction (including details on casing and cementing of Class VI wells),	Section 146.86
Pre-injection logging and testing	Section 146.87
Injection operation requirements	Section 146.88
Ensuring mechanical integrity	Section 146.89
Ensuring financial responsibility for corrective action; injection well plugging; post-injection site care and site closure; and emergency and remedial response	Section 146.85
Ongoing testing, monitoring and reporting	Section 146.90 and 146.91
Injection well plugging	Section 146.92
Post injection site care and site closure	Section 146.93
Emergency and remedial response plan and requirements	Section 146.94

Three aspects of the proposal merit particular attention for those interested in transitioning from incidental to incremental storage of CO_2 along the lines discussed above. First, the preamble to the proposed rule indicates that the EPA does not intend to modify the existing Class II rules governing CO_2 injections for EOR purposes, explaining that:

> CO_2 is currently injected in the U.S. under two well classifications: Class II and Class V experimental technology wells. The requirements in today's proposal, if finalized, would not specifically apply to Class II injection wells or Class V experimental technology injection wells. Class VI requirements would only apply to injection wells specifically permitted for the purpose of G[eologic] S[equestration]. Injection of CO_2 for the purposes of enhanced oil and gas recovery

207. 40 C.F.R. § 144.28(f)(6)(ii)(A) (2008); Injection well operating requirements, 73 Fed. Reg. 43538 (proposed July 25, 2008). *Cf.* proposed § 146.88(a).

208. Some of these testing and monitoring requirements appear to be impractical and unrealistic and will probably be subject to further revision during the rulemaking proceeding.

(EOR/EGR), as long as any production is occurring, will continue to be permitted under the Class II program.[209]

If followed in the final rule, this approach means that if a company limits its CO_2 injections to those required for EOR purposes – in effect engaging solely in the incidental storage of CO_2 as discussed above – the requirements for the new Class VI wells would not apply at all.

Second, the proposed rule offers a limited potential transition pathway for some Class II injection wells to qualify as Class VI storage injection operations, at least under certain circumstances. This transitional mechanism is created by proposed section 146.81(c), which provides a partial exemption for Class II and Class V wells from the casing and cementing requirements where the applicable entity administering the UIC program determines that underground sources of drinking water will not be endangered. In other words – assuming compliance with all other aspects of the new Class VI rules – the operator of an EOR project would be able to use previously permitted Class II and Class V wells for injection purposes (rather than having to drill a new well that complied with the Class VI well construction rules for casing and cementing). A Class II permit holder applying for a Class VI permit for the well would be required to comply with all of the other requirements. The conversion to Class VI status might appear to have the effect of foreclosing the possibility of returning to EOR operations at some future time. As discussed above, however, residual oil will remain in an EOR reservoir at the termination of economic operations together with potentially valuable CO_2. Hence if conversion to Class VI status in fact did foreclose the ability to recover the CO_2 resource and use it to resume EOR operations (either at the initial injection site or elsewhere), EOR operators may be leery of transitioning from incidental storage as a Class II well to incremental storage under a Class VI designation. These issues are also likely to be ventilated during the rulemaking proceeding.

A third aspect of particular interest is the proposed rule's treatment of issues arising under the Resource Conservation and Recovery Act (RCRA)[210] and the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA or Superfund).[211] The EPA recognized that the chemical content of a particular CO_2 stream will depend on its source and on the technology used for capture. As a result, the EPA indicated that it was unable to make a categorical determination of whether any particular injected CO_2 stream were "hazardous" under the RCRA as such a determination would depend on the composition of the particular CO_2 stream. As a result, the agency proposed to effectively limit qualification for Class VI to those CO_2 streams that do not include impurities that would bring the substance within the scope of the RCRA. To accomplish this, the proposed rule simply defines the term "carbon dioxide stream" to exclude "hazardous waste."[212] If adopted as part of a final rule, this

209. Class VI Proposed Rulemaking, *supra* note 204, 73 Fed. Reg. at 43,502 (EPA specifically sought comment on the merits of this approach).

210. 42 U.S.C. § 6901.

211. *Id*. For a discussion of how these statutes might relate to CO2 storage, *see J. Moore*, *supra* note 61.

212. Class VI Proposed Rulemaking, *supra* note 204, at 43,535 (discussing proposed section 146.81(d) stating that the new subpart for Class IV wells "does not apply to any carbon dioxide stream that meets the definition of a hazardous waste under 40 C.F.R. pt. 261").

provision should provide a "bright line" standard for CO_2 pipeline operators to follow by contractually prohibiting suppliers from introducing such substances into the CO_2 stream tendered for purchase, or transportation, and by requiring full indemnification by the CO_2 provider in the event of any breach of the quality specification.

With regard to CERCLA, the proposed rule appears to defer consideration of potential liability issues for resolution in individual Class VI permit proceedings. As with its discussion of RCRA, the proposed rule noted that CO_2 itself is not listed as a hazardous substance under CERCLA, but that a given CO_2 stream may contain other substances (such as mercury) that are so listed. In addition, the EPA also expressed a concern that some constituents of a CO_2 stream could react with groundwater to produce listed hazardous substances such as sulfuric acid. Thus, the question of whether or not a CO_2 storage site could ultimately produce a hazardous substance for purposes of CERCLA depends not only on the make-up of the specific CO_2 stream, but on the environmental media (*e.g.*, soil, groundwater) in which it is stored.[213] Because CERCLA exempts from liability "federally permitted releases" (which includes releases in compliance with a UIC permit under the SDWA),[214] the EPA sought to ensure that its new rule would not authorize inappropriate hazardous releases and stated that Class VI permits "will need to be carefully structured to ensure that they do not 'authorize' inappropriate hazardous releases."[215]

There are several key issues of concern to anyone planning a non-EOR based CO_2 injection program that are not addressed at all, however. One such issue is the question of managing the risk of long-term liability that might result from owning or operating a CO_2 storage facility. The EPA explained that the SDWA does not provide authority to address risks to air, ecosystems, or public health nor to allow EPA to transfer liability from one entity to another.[216] Thus while the EPA has published a supporting document that discusses various approaches to managing long-term liability issues,[217] it has not sought to determine whether any of the various models for managing these liability issues is appropriate.[218] In effect, the proposed rule leaves open the possibility that the owner or operator of a CCS injection site may be held responsible after the post-injection site care period has ended even though financial responsibility under the SDWA has ended.

Another key issue that is left unresolved is the relationship between the state oil and gas commissions that currently regulate drilling and production activities (including administering the EPA's UIC well permitting program) and the environmental or water quality agencies that are responsible for implementing other aspects of water quality protection. Today, there is a generally shared responsibility between these agencies under which the

213. *Id*. at 43,504.

214. *Id*.

215. *Id*.

216. *Id*. at 43,522.

217. EPA, APPROACHES TO GEOLOGIC SEQUESTRATION SITE STEWARDSHIP AFTER SITE CLOSURE (2008), http://www.epa.gov/ogwdw/uic/pdfs/support_uic_co2_stewardshipforsiteclosure.pdf.

218. Class VI Proposed Rulemaking, *supra* note 204, at 43,522.

environmental agency may designate the subsurface location of the drinking water formations to be protected, but the oil and gas commission conducts the review of the intended well completion practices and grants the permit for the CO_2 injection well. Old drilling logs retained by the oil and gas commissions played a significant role in helping the states to identify underground sources of drinking water to be protected under the SDWA and thus aided in the efforts of many states to qualify for primacy in the first place. The allocation of institutional responsibility between these various agencies within individual states is likely to be a key issue to consider in any final rule as well as in ultimate implementation following completion of the rulemaking proceeding. The EPA has specifically invited comment on whether states may qualify to obtain primacy for only Class VI wells without undertaking such responsibility for other well classes within the state. [219]

It is of course very early in the rulemaking process. The agency has indicated that a final rule is not expected to be issued before late in 2010 or early 2011,[220] leaving multiple opportunity for public comment and for policy review. While the evolution of this proceeding is likely to be of great interest to those interested in developing freestanding CO_2 storage sites, the practicalities of the industry discussed above suggest that, at least over the next decade or so, far more CO_2 will be effectively stored via Class II EOR wells than via the proposed new Class VI.

E. Injection and incremental storage of CO_2: Applicability of current legal framework for storing CO_2.

As discussed above, the current literature and, indeed, current domestic and international events indicate that actual implementation of any new statutory scheme governing permanent storage of CO_2 outside of oil and gas-bearing reservoirs is likely some years away. Even if legislation were passed, implementation by the relevant agencies would take considerable time. Moreover, actual implementation of CCS for coal-fired power plants will require new engineering and construction of commercial-sized pilot projects to prove the capture technology on a commercial scale. Only after these initial pilot commercial-scale projects have proven economically successful would deployment of the technology in new coal-fired power plants begin on a commercial scale. What this means is that – regardless of the current, very high level of interest in CCS projects – there will not be actual capture and storage of any considerable quantity of CO_2 *from coal-fired generating plants* for years, and very possibly a decade or more.[221] While CO_2 capture from power plants

219. *Id*. at 43,523.

220. ENVIRONMENTAL PROTECTION AGENCY, MEETING SUMMARY OF PUBLIC WORKSHOP REGARDING PROPOSED UIC REGULATIONS FOR GEOLOGIC SEQUESTRATION OF CARBON DIOXIDE 3 (2008), http://www.epa.gov/safewater/uic/pdfs/page_uic_washingtondc_feburay2008_summary.pdf.

221. *Carbon Capture and Sequestration: An Overview: Hearing before the Subcommittee on Energy and Air Quality of the House Comm. on Energy and Commerce*, 110th Cong. 48-49 (2007) (statement of David G. Hawkins, Director, Climate Center, Natural Resources Defense Council, estimating that it could take one or two decades before broad commercial application of post-combustion capture under normal industrial development scenarios). The lengthy time required for widespread deployment of commercial-scale CCS projects is underscored by the proposed Carbon Capture and Storage Early Deployment Act, H.R. 6258, 110th

may be years away, new anthropogenic sources of CO_2 *from industrial processes* such as ammonia plants and CTL facilities are expected to come on line in the relatively near future.[222] For this reason this article focuses here on a path forward for CCS that may be immediately available to a perspicacious oil and gas operator for creating a transitional path, from the incidental storage of CO_2 that occurs naturally during EOR operations, to a future opportunity post-EOR operations for the incremental storage for CCS purposes.

1. The Interstate Oil and Gas Compact Commission Task Force report and proposed model statute and rules.

The technology of injecting extraneous substances (primarily saltwater) into a producing reservoir has been practiced by the United States oil industry since the late 1940s and early 1950s, long before the use of CO_2 injection for EOR. Hence, state oil and gas conservation agencies have long experience in regulating the injections of extraneous substances in oil and gas bearing formations in order to produce additional hydrocarbons.

In July of 2002, the Interstate Oil and Gas Compact Commission (IOGCC) under the auspices of the DOE convened a meeting of its state representatives and state geologists to explore whether the states could have a meaningful role in carbon dioxide storage.[223] The IOGCC was created in 1935 by a formal agreement among six principal oil and gas producing states and ratified by Congress, as required by the United States Constitution.[224] Its creation resulted from the need for regulating the production of oil (conservation and prevention

Cong. (2nd Sess. 2008), proposes creating an industry-funded corporation to support large scale demonstrations of carbon capture and storage technologies to advance the technologies to commercial readiness over an initial ten to fifteen year period.

222. For example, contracts were announced in 2006 and 2007 for the purchase of captured CO2 from several such non-power generating facilities expected to be constructed in the 2010-2012 time frame, with the CO2 to be used in EOR operations. *See, e.g.*, Press Release, Denbury Resources, Inc., Denbury Signs Agreement to Purchase Additional Manufactured CO2 (June 25, 2007), http://www.secinfo.com/dsvrp.uDX3.d.htm, *and* Press Release, Denbury Resources, Inc., Denbury Resources Inc. Acquires Option to Purchase Another Tertiary Food Candidate; Agreement to Purchase Manufactured Source of CO2 (Nov. 8, 2006), http://findarticles.com/p/articles/mi_m0EIN/is_2006_Nov_8/ai_n27043287. In principle, carbon capture can be retrofitted on existing power plants. But because the cost of retrofitting existing facilities is expected to be considerably greater than for newly constructed facilities, carbon capture technology is not likely to be applied to existing facilities until well after it is adopted in the construction of new generating stations. Hence, retrofitting existing facilities is not likely to be widespread for a number of decades.

223. When created in 1935, the organization was named the Interstate Oil Compact Commission. It was renamed in 1991 to better reflect the fact that its scope included natural gas as well as oil. The Commission is an interstate compact approved by the US Congress and made up of representatives of all the states that have active oil and gas projects within their boundaries. *See, e.g.*, www.iogcc.state.ok.us (last accessed June 25, 2008).

224. The Constitution prohibits agreements or compacts between States without the prior approval of the Congress. U.S. CONST. art. I, § 10, cl. 3. There is of course abundant literature on the topic. The classic early review of the law governing such interstate compacts is Felix Frankfurter & James M. Landis, *The Compact Clause of the Constitution A Study in Interstate Adjustments*, 34 Yale L.J. 685 (1925). With regard to the use of an interstate compact to address oil conservation specifically, *see* Northcutt Ely, *Oil Conservation through Interstate Agreement*, (Government Printing Office 1933). For a more recent review of the law of interstate compacts as it might apply to regional electricity holding companies, *see* Frank P. Darr, *Electric Holding Company Regulation By Multistate Compact* 14 ENERGY L.J. 357 (1993).

of waste of oil), which required cooperation among the states when there was also strong opposition to any form of federal control. The organization is empowered by its charter to recommend inter alia "the coordination of the exercise of the police powers of the several States within their several jurisdictions to promote the maximum ultimate recovery from the petroleum reserves of said States, and to recommend measures for the maximum ultimate recovery of oil and gas."[225] State conservation commissions have been applying conservation statutes and the regulatory rules under which they operate for nearly seventy years. Hence, there is no better group to review the interaction and the potential application of existing state oil and gas law with the opportunities for storing carbon dioxide in existing oil and gas reservoirs within a state's boundaries.

Following the 2002 meeting, the IOGCC established a Geological CO_2 Sequestration Task Force that began its work in July of 2003 with funding by the DOE and the National Energy Technology Laboratory (NETL). This task force included not only the IOGCC member states but representatives from the state oil and gas agencies, from several Canadian provinces and their provincial oil and gas agencies, from the DOE and DOE-sponsored Regional Carbon Sequestration Partnerships, from the Association of American State Geologists and from members from the oil and natural gas industry – in sum, an inclusive group. In 2006, the task force expanded to include representatives from the EPA and the BLM. Phase I of the task force's work was directed toward studying technical, policy and regulatory issues pertaining to EOR and long-term CO_2 storage in all three potential CO_2 storage formations, *i.e.*, oil and natural gas fields, coal seams, and deep saline formations.

In September of 2007, the task force issued its final report, entitled "Storage of Carbon Dioxide in Geologic Structures, a Legal and Regulatory Guide for States and Provinces."[226] It is an excellent source of ideas, information, and analysis regarding carbon dioxide storage and draws on the vast practical experience of the state agencies in regulating, not only underground injections of various materials in conjunction with enhanced oil and gas production, but also the necessity of pooling of mineral ownership interests required to operationally manage an entire oil and gas reservoir. The report culminates in a proposed Model Statute for Geologic Storage of Carbon Dioxide and attendant model rules and regulations.[227] These Model statutes and regulations provide a very good summary of the areas of the law that need to be addressed for the period of time after incidental storage for EOR has ended and at the point at which incremental storage for strictly CCS purposes might begin.[228]

225. IOGCC Charter art. 6, *available at* http://www.iogcc.state.ok.us.charter (last visited Sep. 4, 2008).

226. THE INTERSTATE OIL AND GAS COMPACT COMMISSION TASK FORCE ON CARBON CAPTURE AND GEOLOGIC STORAGE, STORAGE OF CARBON DIOXIDE IN GEOLOGIC STRUCTURES: A LEGAL AND REGULATORY GUIDE FOR STATES AND PROVINCES (Sept. 25, 2007) http://iogcc.publishpath.com/Websites/iogcc/PDFS/2008-CO2-Storage-Legal-and-Regulatory-Guide-for-States-Full-Report.pdf [hereinafter IOGCC MODEL STATUTE AND RULES FOR CCS].

227. *See also id*. at App. I, II.

228. The IOGCC also provides a state-by-state (and Canadian province) update on CO2 storage legal and regulatory developments at http://www.iogcc.state.ok.us/Websites/iogcc/Images/CO2-State-Updates.pdf (last visited July 14, 2008).

As shown below, the proposals are limited, however, because they are based almost entirely on the traditional natural gas storage model and do not address potential EOR projects except for the period after EOR operations terminate and the conversion of the site to non-EOR storage of CO_2, at which point the assumption is that regulatory responsibility would be transferred from the oil and gas commission to a state environmental or water quality agency.[229] While it is admirable that the IOGCC took the initiative to plan for the conversion of EOR projects to CCS, the proposed Model Statute appears to preclude any further recovery of residual oil under future technology from an EOR project. As detailed below, this is a serious drawback and reflects the limitations of viewing the problem as simply analogous to traditional natural gas storage.

2. The limits of the natural gas storage analogy – the pore space debate.

A portion of the IOGCC report reviews much of the case law of the various states regarding property rights with respect to the underground space that will be utilized for the carbon dioxide storage.[230] The task force report recognizes the need for legal clarity in this area because of the disparity among state laws as well as in their interpretation by the courts (both federal and state). The report reflects the views typically presented by university scholars[231] that the pore space used for CO_2 storage should be viewed as it has been for natural gas storage. Under this natural gas storage analogy, the pore space generally would belong to the surface owner and would be subject to the same property law rules that apply in a given state for pore space used for natural gas storage. But, while CO_2 storage is analogous to natural gas storage in a number of ways, it differs in several important aspects. The incidental CO_2 storage in EOR operations involves injecting *an extraneous substance* – CO_2 – into the reservoir (whereas natural gas storage involves injecting only more natural gas into the reservoir). In addition, there will remain oil in the reservoir that belongs to the owners of the mineral interests. As explained below, these differences mean that the pore-space ownership of the surface owner should pertain only to actual *available* pore space (*i.e.* not occupied by residual oil) and that a large and significant portion of the pore space in an EOR project will in fact *not* be initially available at the end of an EOR project because of the presence of that residual oil, which may be potentially recoverable.

A brief summary of basic mineral property law sets the stage for explaining the importance of these distinctions. Because oil, natural gas, and other minerals are typically buried below the surface, when the mineral interest becomes severed from the surface interest, the mineral interest owner retains a right of use of the surface to extract the minerals. At what point in time does he lose this

229. IOGCC MODEL STATUTE AND RULES FOR CCS, *supra* note 226, at App. 1, § 10 n.10.

230. *Id*. at Pt. 2 (Analysis of Property Rights Issues Related to Underground Space Used for Geologic Storage of Carbon Dioxide).

231. *See, e.g.*, Elizabeth J. Wilson & Mark A. de Figueirdo, *Geologic Carbon Dioxide Sequestration: An Analysis of Subsurface Property Law*, 36 E.L.R. 10114, 10121 (2006) and Owen L. Anderson, *Geologic CO2 Sequestration: Who Owns the Pore Space?* presentation at the University of Texas School of Law Climate Change Seminar, Apr. 24-25, 2008 (Austin Texas).

right? The cited IOGCC report, and the footnoted articles, regarding ownership of the subsurface pore space, provides a very good review for scholars interested in this topic. The basic gist of the courts in distinguishing subsurface pore space rights as belonging to the surface owner or the mineral owner generally relates to whether there may be remaining minerals in the potential storage reservoir. The court cases applying the law in this area are not always easy to reconcile. In one Texas case the court decided that, because the extraction of the mineral at issue there (salt) actually resulted in the formation of the underground cavern (since the remaining cavern walls were made of salt); the underground cavern belonged to the mineral owner, not the surface owner.[232] And yet, in a prior case involving natural gas storage, the Texas Supreme Court decided that when a property owner deeded a fee interest to the mineral owner and reserved only a perpetual royalty interest, the retained interest in the subsurface pore space was essentially *in the mineral* (the native natural gas) still remaining in the porous formation (although unrecoverable and indistinguishable from the mineral owner's natural gas being stored in the available pore space).[233]

This judicial finding is similar to the statutory rule for storage of natural gas and compressed air (another non-hydrocarbon gas) in depleted underground reservoirs in Mississippi which recognizes both surface and subsurface rights by requiring the majority consent of all owners, of both the surface and subsurface rights, prior to the State Oil and Gas Board permitting an underground gas storage project.[234] Interestingly, Mississippi has no case law on the subject of ownership of pore space. Further, the applicable Mississippi eminent domain statutes recognize that there is a public interest in the storage of gas that may justify the taking of the natural gas of remaining non-consenting interests and hence provides for adequate and fair compensation for any native gas condemned that would have otherwise been capable of commercial production.[235]

3. Compulsory Unitization of Mineral Ownership.

Somewhat in the same genre as the use of eminent domain for condemning gas storage rights are statutes that permit an operator to compulsorily pool multiple separately owned mineral interests[236] in order to operate a known oil and gas reservoir as a single project. Many (but not all) of the member states of the IOGCC have such statutes, which generally provide that after obtaining the statutory percentage of approvals, the operator may effectively force the remaining non-consenting leased and unleased mineral interest owners and non-consenting operators to operate the reservoir as if it were one large pool. The advantage of this approach is that it typically ensures the increased total recovery

232. Mapco, Inc. v. Carter, 808 S.W. 2d 262, 277-278 (Tex. App. – Beaumont 1991).

233. Humble Oil & Refining Co. v. West, 508 S.W. 2d 812, 818-819 (Tex. 1974).

234. MISS. CODE ANN. § 53-3-155(b) (1992).

235. *Id*. § 53-3-159(b).

236. INTERSTATE OIL AND GAS COMPACT COMM'N, IOGCC MODEL STATUTE AND FIELDWIDE UNITIZATION REFERENCES 9 http://iogcc.publishpath.com/Websites/iogcc/docs/iogcc_model_statute_and_fieldwide_unitization_references.pdf (last visited Sept. 4, 2008) [hereinafter IOGCC MODEL STATUTE AND FIELDWIDE UNITIZATION REFERENCES].

of oil and gas as compared to allowing each separate owner to drill individual wells on its own tract. Maximizing total production (while minimizing costs) is obviously of significant economic interest to both the state and to the owners within the reservoir. Also, by treating the target reservoir as if it were a single property, the operator may use the most strategic development pattern for the project, including locations for production-enhancing injection wells for substances such as saltwater or CO_2. This normally results in greater recovery of oil and gas from the formation than would otherwise be recovered utilizing a more expensive, capital intensive lease basis[237] and also reduces the amount of residual oil left in the reservoir at the termination of the project, leaving more available pore space for other purposes (including potential incremental CO_2 storage).

While the details of the terminology may vary in some states, these pooled operations are generally deemed to be "Unit Operations" and are generally governed by two primary documents: a Unit Agreement and a Unit Operating Agreement. The *Unit Agreement* is the document which commits the leaseholders (working interests), their mineral lessors (royalty owners) and the unleased mineral interests (treated proportionately as working interest and royalty interest) to the pooling of their mineral interest in the particular subsurface formation encompassed within a prescribed area. This document confers rights upon the working interest owners to operate the reservoir as a pool and to accomplish the enhanced recovery by the means and methods set forth in a *Unit Operating Agreement*, which is signed by all the working interest owners. Another important provision of the Unit Agreement is the agreement of the parties to conform their individual leases to the extent necessary to allow the unit operation. This includes access to the surface across the lands of one tract to accommodate operations on an adjoining tract. These operations may include drilling, injection, siting tank batteries for storage, building compression facilities, and even recycling plants. Hence, operations of a pooled unit are similar but generally more equipment-intensive than for a gas storage facility.

The state statutes that provide for unitization generally do not require unanimity, but only agreement by a certain percentage of the working interest owners and the royalty owners before seeking approval for the project at the state oil and gas commission.[238] The non-committing owners may then be

237. Thus, long before Professor Hardin unleashed a river of commentary, analysis and controversy with his brief essay about the "Tragedy of the Commons" (162 Science 1243 (Dec. 1968)), the oil and gas industry had already recognized the need for cooperative action to avoid waste through overproduction and created and implemented practical tools to encourage maximum overall production under terms that generally protect the complex and disparate property rights of affected parties. For a general review of the law of pooling and unitization, *see generally* BRUCE M. KRAMER & PATRICK H. MARTIN, THE LAW OF POOLING AND UNITIZATION (Matthew Bender 1957) (1998).

238. The percentage required varies from state to state, but is generally between fifty and eighty percent, with most of the older producing states being in the middle range of sixty-five to seventy-five percent. *See* IOGCC MODEL STATUTE AND FIELDWIDE UNITIZATION REFERENCES, *supra* note 236, at 9. Since unitization statutes are rarely amended, this chart is probably still current. The report was prepared to review potential changes in the model unitization statute in light of development of horizontal drilling technology. The Committee opined that a "minimum" required majority percentage was desirable to avoid placing too heavy a burden on unit formation and in recognition of the practical problems often encountered in obtaining ratification of the royalty owners (*e.g.*, numerous royalty owners, difficulties in locating).

"forced" into the unit. This aspect of compulsory unitization is somewhat analogous to the condemnation of property for underground storage, except that the interests that are included do not lose their property interest, but rather participate in the unit operations as if all owners had agreed to the project. A working interest owner will thus pay its share of expenses and a royalty interest owner will be paid its share of revenue free of cost.[239] The royalty owners, in turn, are paid on the basis of their oil and gas leases (with no obligation for any operating expenses), subject to the oil and gas leases that they let to an operator, modified only to the extent that their tract in the Unit contributes to the enhanced recovery of oil and gas. In sum then, the benefit of compulsory unitization is that the oil and gas reservoir is operated as one pool to the maximum benefit of all the owners to recover the maximum amount of oil and gas from the reservoir with the most economical investment in the recovery. This ability to bind all owners into the operation of an enhanced recovery operation, without necessarily quashing their rights as mineral owners, is thus, an important aspect of the conservation statutes already in place in most United States oil and gas producing states.

Texas, however, is an exception. Despite its leading role as an oil and gas producing state, Texas has never been able to muster enough support in its legislature to pass such a statute due to opposition from the powerful lobby of the independent oil producers.[240] Therefore, although unitization is widely used in Texas, it is voluntary, and must be achieved through negotiation, with the end result that leases not included in a unit plan must be administered independently and the production accounted for as if that portion of the reservoir were not in the unit. The drawback of the Texas regime is that if most of the reservoir is undergoing enhanced recovery operations, a non-participating independent owner may see some production benefit for which he made no investment (a "free-rider" problem), or may see no benefit because the working interest owners who developed the unit select a recovery program that does not enhance the non-participating lease, thereby most likely than not leaving some otherwise recoverable oil and gas behind (resulting in non-optimal recovery of resources).

The absence of compulsory unitization in Texas, thus, hinders the increased use of advanced production techniques (including CO_2-based EOR) and would also appear likely to disfavor the development of CO_2 storage in the state as compared to other oil and gas producing states. As a result, perhaps the Texas

239. While forced unitization is similar to condemnation in that both involve an exercise of governmental power over private property, it differs in that the party compelled to participate in a unit retains their property interest and shares in costs and benefits of the unit.

240. IOGCC MODEL STATUTE AND FIELDWIDE UNITIZATION REFERENCES, *supra* note 236, at 160 (Appendix M). In 1997 when unitization legislation was proposed in Texas (in House Bill 1624), a study was published estimating that if Texas had had a compulsory unitization statute similar to New Mexico, during the 1977-1995 period, oil production from the Permian Basin region alone would have increased by 1.4 billion barrels. David Ivanovich , "Texas unitization fight reopened with proposed legislation", The Oklahoma Journal Record (Mar. 27, 1997), http://findarticles.com/p/articles/mi_qn4182/is_19970327/ai_n10103078. Nevertheless, the proposal was stopped by opposition from independent oil producers. The principal concern was apparently that the producer's revenue stream from primary production would be endangered by the up-front implementation costs for unitization. The amendments offered by the independent producers essentially would have netted operating costs against income and provide a device to pay operating and capital costs out of future revenue.

Legislature may revisit the question of compulsory unitization legislation in the future in order to achieve comparability with other producing states that compete for investment dollars from the producing industry and under the auspices of potentially creating geologic sites for storage of incremental CO_2.

Another very important aspect of the compulsory unitization statutes is, that in order for such a unit to be approved by the state oil and gas agency, the operator must show that he has delineated the reservoir to such an extent that he can demonstrate that no adverse impact shall occur to offsetting properties during his enhanced recovery operation because he has included all the viable reservoir within the Unit boundaries. In order to make this showing, the production from the reservoir and the characteristics of the producing strata are studied by a team of geologists and reservoir engineers who then present evidence to the applicable state agency showing that the oil and gas reservoir is a finite area with defined boundaries. These boundaries may result from porosity and permeability pinch-outs, encroaching water tables, underground ceiling faults, or whatever other limiting factors can be geologically or operationally demonstrated. Typically, this evidence is presented at a trial-type hearing to examiners that are technical and legal, and in many states before the entire oil and gas conservation commission. The testimony must show that the reservoir is defined sufficiently to encompass the area that will undergo enhanced recovery operations, satisfy the hearing examiner(s) that oil and gas will not migrate outside the project, that no injected substance (including, for example, the CO_2 injected in a CO_2 flood) will migrate outside the unit boundary, and that no oil and gas owner within the Unit area will have oil and gas pushed off his lease, never to be recovered.

These procedures ensure that at the time the EOR project is initially formed, there is a well-defined subsurface interval (the Unitized Formation) that is capable of containing the injected substance while increasing the production of oil and gas from the pressurized reservoir. As long as an operator can show that the moneys spent to develop the enhanced recovery project are less than the value of the additional oil and gas to be recovered, the project is usually approved by the oil and gas agency. When the unit project terminates and all commercial oil and gas production ceases, the oil and gas leases that were pooled would normally terminate as well and therefore, the compulsory pooling itself expires.

4. Implications for CO_2 storage.

What does this experience with EOR operations mean for storage of anthropogenic CO_2? It means that in all states where secondary and other enhanced recovery projects have been approved by the various state agencies, there are well-defined storage possibilities for CO_2 where the owners of the minerals (lessees, lessors, and unleased owners) have already combined their interests, or had their interests combined for them by the state, after a rigorous review of the site and the proposed operations for the benefit of themselves and the state. In view of the spotlight on potential carbon storage operations, this early compulsory action may have significance if the unitized reservoir has further utility as a CO_2 storage site, and if the involved parties in the Unit can be convinced to maintain their collective interests beyond the economic life of the oil and gas project under current practices.

Because "there is no Federal general common law"[241] and property rights are principally creatures of state law,[242] it is state – not federal – law that will generally govern the rights of access to the minerals below the surface of the earth in these spent oil and gas reservoirs, and that will control the relationships among the rights of any owner of the surface with respect to the other owners that may have residual mineral rights. In a nutshell, under applicable state property law, the mineral owner generally has the right to use so much of the airspace, surface and subsurface to explore for and exploit the minerals[243] subject to the limitations of the accommodation doctrine.[244] This doctrine basically provides that use of the surface by the mineral owner will be exercised with due regard for the rights of the surface owner and his use of the surface.

Of the thirty-one states that make up the IOGCC, nine already have CO_2-based enhanced recovery projects, including Mississippi, Louisiana, Kentucky, Colorado, New Mexico, Oklahoma, Texas, and Wyoming. Even though sources of CO_2 that could be used for EOR projects are yet to be developed in other states, twenty-seven of the member states of the IOGCC[245] have in place the legal and regulatory regime for oil conservation that provides for enhanced oil and gas recovery projects within their state borders. This means that most oil and gas producing states could approve the injection of CO_2 for the enhanced recovery of oil and gas under their current legal and regulatory framework, if additional CO_2 supplies were available.[246] Even today, a number of these states have operating oil and gas projects that, in the utilization of saltwater injection, have essentially the same reservoir mechanisms working for the enhanced recovery of oil and gas – *i.e.*, pressuring up a reservoir and/or sweeping the reservoir of residual oil and gas in place, such that when the project is economically terminated, the injected saltwater remains incidentally but effectively stored in the reservoir in perpetuity. This same conclusion applies in CO_2 enhanced recovery projects.

241. Erie R.R. Co. v. Tompkins, 304 U.S. 64, 78 (1938). *See also* Henry J. Friendly, *In Praise of Erie – and of the New Federal Common Law*, 39 N.Y.U. L. REV. 383 (1964).

242. Chongris v. Board Of Appeals of the Town of Andover, 811 F.2d 36 (1st Cir. 1987) ("[i]t is likewise a black-letter certainty that property rights, while protected by the federal Constitution, are creatures of state law," *citing* Bishop v. Wood, 426 U.S. 341, 344 n.7 (1976)).

243. Getty Oil v Jones, 470 S.W.2d 618, 621 (Tex. 1971).

244. *See id*. and Sun Oil v Whitaker, 483 S.W.2d 808, 810 (Tex 1972). For a more detailed discussion of the relationship between a mineral owner (or lessee working interest owner) and the surface owner, *see also* Owen L. Anderson, Geologic CO2 Sequestration: Who owns the pore space?, presented at the University of Texas (Apr. 24-25, 2008) (copy on file with author).

245. INTERSTATE OIL & GAS COMPACT COMM'N, CO_2 STORAGE: A LEGAL AND REGULATORY GUIDE FOR STATES (2008), http://iogcc.publishpath.com/Websites/iogcc/pdfs/Road-to-a-Greener-Energy-Future.pdf. IOGCC MODEL STATUTE AND FIELDWIDE UNITIZATION REFERENCES, *supra*, n. 236.

246. Indeed, in 2007, a survey of state agencies that issue well permits under the UIC program discussed above explicitly found that most states indicated that they could use their existing regulations to issue permits for a non-EOR CO2 injection well. Some of the oil and gas commissions indicated that they could not issue permits for non-EOR CO2 injection wells, but instead would send the application to the relevant state environmental agency. GWPC CO2 Well Survey, *supra* note 6, at 9. A number of the state agencies indicated, however, that additional staffing resources would be required.

Similarly, if there is no further utility for such a reservoir, when a CO_2-based project has recovered as much oil as can be economically displaced by the then-current technology, the injected CO_2 will be left in the ground permanently. Therefore, it is important to recognize that carbon storage operations are already occurring, albeit, incidentally and under the name of enhanced recovery without any need to amend any present laws, rules and regulations. Indeed, many Unit Agreements recognize that an operator may use many means and methods to enhance the recovery of oil and gas and generally give the working interest owners the right to change such operations as the working interest owners see fit under some percentage approval by those parties paying the costs for such efforts as set forth in the Unit Operating Agreement.

This existing legal and institutional structure means that an operator planning ahead for future potential use of the reservoir for incremental storage of CO_2 need only take one more step than has been traditional in the past in preparing for unit operations. That additional step is to initially solicit and incorporate into the traditional EOR unitization documents the agreements of the working interest and mineral interest owners to the future potential use for CCS storage. This could be done by including in the Unit Agreement the extension of the oil and gas leases *beyond termination* of the Unit and through a future potential CO_2 storage term, which term would be until the CO_2 storage project itself were actually permanently terminated and sealed (comparable to the "post-closure" period in the IOGCC report at which time ownership would transfer to a governmental or quasi-governmental entity). This action alone would allow the operator to later produce commercially available oil under future technology or produce oil that might be associated with produced CO_2 that could be withdrawn for other use. It could also provide the mechanism whereby the mineral interest owner consents to his residual pore space being utilized for CO_2 storage. Likewise, the Unit Operating Agreement could be expanded to include new definitions for a CO_2 storage Unit Operation post EOR, so that the operator would have early approval of those owners required by a regulatory agency for future approval of a CO_2 storage project. With the inclusion of the surface owner(s) in this early development planning, the progression of an EOR project into a carbon dioxide storage project can be handled reasonably seamlessly with only slight additions to, or tweaking of, current state oil and gas and property laws.[247]

Assuming changes to the EPA's existing regulations to allow incremental injections of CO2 to continue following oil and gas operations, this scenario could thus be undertaken under the current statutory and case law, with careful drafting of the Unit Agreement, Unit Operating Agreement, and the necessary future leases and grants of storage rights with the mineral and surface owners. Moreover, unlike an underground site developed only for permanent CCS storage, an EOR-based site may accommodate incremental storage beyond the life of an enhanced recovery project without totally precluding the future

247. Where the surface owner remains the owner of the minerals (fee owner) and thus would have the ownership rights in the available pore space attributable to such surface owner, it is possible this approach would be even more feasible. Where the surface ownership has been partitioned from the ownership of the minerals, this would pose a more difficult task.

potential of additional enhanced recovery. When one ponders the technological accomplishments of the oil and gas industry in just the last twenty years, it is easy to realize how important it is for oil and gas attorneys to plan ahead for further potential advances a decade or two or three ahead. The key element for inducing surface owners to join in such a progressive project is that even though they may suffer some actual surface intrusions while the enhanced recovery project takes place, they have the prospect of having future compensable ownership interest in the site. The mineral owners, on the other hand, even after the project transitions from incidental CO_2 storage to incremental CO_2 storage, can still look forward to the possibility of future oil and gas production and royalty payments if recovery technologies can be utilized to economically justify returning the oil and gas reservoir to an enhanced recovery project. Under current technology there are *always* residual hydrocarbons that remain in the unitized formation at the time it becomes uneconomic to continue production. Hence, if technology, economics and the price of oil were to justify a return to oil and gas production, the operator could proceed to do just that – if he had planned ahead and obtained all the contractual owner approvals evidenced in his Unit Agreement and Unit Operating Agreement as well as the proper storage rights. Again, many oil and gas producing states have the necessary legal and regulatory framework to allow for this to occur under current law. For those that do not, it could very well be a simple matter to legislatively get them up to speed.

5. The missing links.

What most state conservation and property laws do *not* include at this time, however, is a clear definition of the rules that will govern the site when the reservoir is full of the additional CO_2 and is unable to take any more volume (*i.e.* the "closure" and "post-closure" periods in the terminology of the IOGCC report). Such rules will be needed for a permanent storage project of incremental volumes injected for the sole purpose of underground storage.

Currently, when an EOR project terminates, the production and injection wells are plugged pursuant to applicable state regulations, surface facilities are removed and abandoned, and all operations come to an end. Under existing rules, there is no further monitoring for leakage or potential migration, nor is there further use of the reservoir (at least under current technology). If an existing unitization project is to transition from an enhanced oil and gas recovery project with incidental storage of CO_2 to a permanent CCS storage site for incremental volumes, the states will have to determine what entity will be liable for the future oversight and maintenance of such a project, for how long this may occur, and who will pay for permanent, virtually perpetual caretaking (as well as how to fund potential future remediation operations in the event they are required).

The states have already begun addressing these issues. The recently passed Texas statute,[248] for example, which provides for a tax benefit for an

248. H.B. 3732, Legis. Sess. 80(R) of Texas provided for inclusion of anthropogenic CO2 in EOR projects under current Railroad Commission authority but did not mandate rulemaking, and geologic sequestration shall be permitted by the Texas Commission on Environmental Quality.

anthropogenic CO_2 storage project also provides that such project shall contain ninety-nine percent of the stored CO_2 for a thousand years. Interestingly enough there was no Texas companion legislation passed as a general CO_2 storage statute, as was done in Wyoming.[249] The Wyoming statute provides for transfer of regulatory responsibility of an EOR project that is a candidate for CCS from the Wyoming Oil and Gas Commission to the Department of Environmental Quality and a companion bill declares the surface owner to be the owner of the available pore space for storage. These statutes presume, however, (as does the Mississippi underground storage statute referenced above),[250] that there will be no further possibility of future oil and gas production from a reservoir. Yet as noted above, in this age of worldwide high oil prices, this appears somewhat short-sighted. While the Mississippi Oil and Gas Board retains oversight over gas storage, the Wyoming statute implies, for example, that efforts to re-establish oil or gas production in the future might be reviewed by the environmental regulatory agency rather than the oil and gas regulatory agency, a somewhat anomalous result. Such a result may not have been intended and other state legislatures might be advised to consider more deliberately possible unintended consequences when enacting laws that will have such long-lasting impact.

Although the Model Statue proposed by the IOGCC Report did not propose any specific state regulatory agency for CCS, the experience of the last seventy years suggests the wisdom of leaving the regulation of such reservoirs under the oil and gas regulatory authority for the period of interim incremental storage and withdrawal of CO_2 (together with associated oil and gas production should such production be come commercially attractive). With many years expected to transpire before commercial scale volumes of CO_2 from power plants exceed the capacity of the EOR industry to use in EOR operations,[251] the regulators and law-makers should encourage this EOR use by considering changes to accommodate this transitional approach.

This more limited – but more directly pragmatic – approach could present real prospects for success in transitioning from EOR to CCS injections, and even withdrawal, because of the limited sources of CO_2 for enhanced recovery projects in most oil and gas producing states. Once CO_2 is transported from the source to be utilized in oil and gas projects that are located farther and farther from the original source, there may often be a separate value in temporarily "bottling up" or storing the CO_2 in a depleted reservoir operation until another EOR project is developed nearby that can use the locally-available CO_2. Obtaining the earlier consents from the owners could allow such an interim activity, providing for more efficient use and re-use of available CO_2 volumes. Regulatory and legal recognition that CO_2 has a multiple-use value while at the same time acknowledging that storage in various reservoirs is still "permanent" for purposes of carbon emissions credits (*i.e*. so long as the CO_2 remains in the

249. H.B. Bill 90, 59th Leg. (Wyo. 2008) (Enrolled Act No. 25).

250. MISS. CODE ANN. § 53-3-155(a) (1992).

251. In late 2006, the Chairman of the Texas Railroad Commission noted that state's oil industry was experiencing a supply shortage of CO2 over the past few years, then estimated to be about 500,000 Mcf per day. News Release, Williams Discusses CO_2 EOR (Dec. 4, 2006), http://www.rrc.state.tx.us/news-releases/2006/120406.html.

closed system of oil reservoirs, surface pipeline and injection and production wells) could help establish the United States as a world leader in developing sequestration opportunities. Foresighted action by United States lawmakers to "tweak" the existing applicable law can provide a regime under which this could occur.

This potential for re-cycling CO_2 was recognized in recent legislation passed by Oklahoma.[252] The Oklahoma legislation was initially drafted as a law favoring geologic storage but was ultimately amended to authorize the appointment of an Oklahoma Geologic Storage of Carbon Dioxide Task Force. It includes provisions explicitly recognizing that the capture, recovery and geologic storage of CO_2 will benefit Oklahoma's citizens and that CO_2 is a valuable commodity to its citizens. The Oklahoma law further provides that geologic storage of CO_2 will allow orderly withdrawal of CO_2 for commercial, industrial or other uses and that current state statutes and agency rules governing CO_2 for EOR purposes are "sufficient to protect the environment and human health."[253] This language of course is actually taken from the IOGCC Model Statute's "Legislative Declaration".[254] The Oklahoma statute sets the current standard for making full use of existing EOR law and regulation for the present storage of CO_2, while planning for future storage, or even for temporary storage, after an EOR project has reached the end of its economic life as an oil producing field. As an institutional matter, this approach allows for the oil and gas agencies to retain regulatory authority over a former EOR project until it becomes a permanent CCS-focused storage site.[255]

Because almost every one of the states that belong to the IOGCC (excepting Texas) have compulsory unitization statutes modeled after the IOGCC model unitization statute and have regulations similar to those of Oklahoma (the first state to have a compulsory law on the unitization of mineral interests for the purposes of enhanced recovery of oil and gas), these other states have the same legal basis to legislatively declare that there is a public interest in the capture, recovery and storage of CO_2. After all, the members of the IOGCC task force already supported the concept in the IOGCC Model Statute and Rules. Such an approach may be especially important for states that, like Oklahoma, do not (at least as yet) have any naturally-occurring sources of CO_2 and thus will likely need anthropogenic supplies of CO_2 for new EOR operations.

In the case of Mississippi, the underground natural gas storage law was amended in 1991 to include "compressed air," defined as nonhydrocarbon gas.[256] This statute discussed earlier not only provides for all surface and mineral consents (fifty-one percent) that should be required, it recognized the need to

252. "The Geologic Storage of Carbon Dioxide Act", Enrolled Senate Bill No. 1765, 2nd Session of the 51st Legislature (Okla. 2008). 2008 O.S.L. 386 (effective January 1, 2009).

253. *Id.*, § 1A, 1-4.

254. IOGCC MODEL STATUTE AND RULES FOR CCS, *supra* note 226, at 32.

255. *Id*. at 10. The IOGCC Task Force recognized of course that states without an existing oil and gas regulatory framework might choose to designate an environmental agency or public utility commission as the lead agency for the state for addressing these issues.

256. MISS. CODE ANN. § 53-3-151(d) (1992) (providing that "[c]ompressed air" shall mean any nonhydrocarbon gas).

store and withdraw the natural gas or compressed air for the public interest.[257] With regard to the institutional issue of allocating regulatory responsibility within the state, the statute provided for the approvals to be administered by the State Board of Oil and Gas.[258] Consistent with its recognition that these activities are in the public interest, it further authorizes eminent domain to acquire all surface and subsurface rights necessary and useful for the purpose of storing natural gas or compressed air.[259]

Amending the storage statutes of other states to include analogous provisions might also further the transition from EOR-based interim storage of CO_2 to incremental storage for CCS purposes. When an activity is deemed to be in the public interest, it is easier to establish the legal basis for obtaining condemnation rights. Indeed, most of the early case law[260] justifying unitization statutes for enhanced oil and gas recovery turned on the fact that the pooling of an owner's mineral interests to achieve increased recovery of the oil and gas reserves for the benefit of the state and the owners was deemed more important than an individual's right not to join in such a project.[261] This is exactly the same type of legal reasoning that underlies statutory eminent domain rights in the public interest for rights of way for construction of roadways and power lines, for example. If the public is benefited by the storage of anthropogenic CO_2, and if the use of this anthropogenic CO_2 in EOR commences such storage, then laws similar to that of Mississippi could provide a near-term solution if: (a) they were amended to include CO_2, and (b) added an eminent domain procedure allowing condemnation of the surface and subsurface pore space for either the temporary storing and withdrawal of CO_2, or for more permanent storage of CCS.

The use of eminent domain is, of course, a creature of constitutional law.[262] A public interest finding for carbon dioxide storage provides the same underlying basis for ranking community interests above individual property rights as in other infrastructure projects benefiting the broader community and could justify some form of condemnation of a reservoir's pore space interests (and surface interests) in order to obtain a geologic storage site satisfactory for the storage of anthropogenic CO_2.

In sum, underlying current proposals to declare that the pore space of a depleted reservoir belongs to a surface owner[263] (much as any other non-mineral

257. *Id*. § 53-3-153.

258. *Id*. § 53-3-155.

259. *Id*. § 53-3-159.

260. Palmer Oil Corp. v Phillips Petroleum Co., 231 P. 2d. 997, 1012 (Okla. 1951); Crichton v. Lee, 25 So. 2d 229, 234-235 (La. 1946); Woody v. Corp. Comm'n, 265 P. 2d 1102, 1107 (Okla. 1954).

261. *Id*.

262. An OLR Research Report found that "[e]very state but one has constitutional provisions barring the taking of private property for public use without just compensation." KEVIN E. MCCARTHY, CONN. GENERAL ASSEMBLY, OFFICE OF LEGISLATIVE RESEARCH, "PUBLIC USE" AND EMINENT DOMAIN (July 27, 2005), http://www.cga.ct.gov/2005/rpt/2005-R-0570.htm. While North Carolina's constitution has no eminent domain provision, the State's Supreme Court has held the public use requirement is an inherent part of the constitution's Due Process Clause. N.C. State Highway Commission v Farm Equip. Co., 189 S.E. 2d 272 (1972).

263. *See, e.g.*, IOGCC MODEL STATUTE AND RULES FOR CCS, *supra* ,note 226.

bearing strata) is the principle that the mineral owner's right is to *extract* the mineral *from* the strata, and not to own in the strata itself. The principle may be sound – but referring back to the earlier discussion of *available pore* space coupled with the relevant facts regarding EOR projects, they do markedly differ from the natural gas storage projects upon which these proposals seem to be based.

- First, the injection of CO_2 into an oil and gas reservoir is the injection of an *extraneous material* to the contents of the stratum. It is not natural gas which already occupied the pore space of the reservoir and of which an indistinguishable unrecoverable portion will remain in the reservoir as a buffer after depletion, never to be recovered.
- Second, and as stressed above, there will be residual oil (and in some cases associated gas) remaining in the reservoir after the EOR project reaches its *current* economic state of depletion and this oil may become recoverable at a future time under future technology. After all, this is exactly what CO_2-based EOR has made possible for oil that was previously viewed as non-recoverable. This residual oil continues to belong to the mineral interest owner and could conceivably be reduced to future possession. The occupation of pore space by CO_2 at the end of a current EOR project thus in itself has a current value in the nature of an option for reserving the potential for that future oil production. In sum, the determination of the amount of pore space that is available for incremental storage for CCS purposes must recognize the existing property interests in the residual oil.

This is why analogies to the typical gas storage projects that liken a storage reservoir to an underground tank battery are inadequate and indeed misleading. The natural gas storage analogy fails to take into account the dynamics of actual oil and gas production and the fact that the ownership of the various interests (including the mineral interest) are governed by well-established state property law, often including well-established case law. And, in the instance of one state discussed here, Mississippi, the issue has never been decided, but the storage statute requires all owners to be considered. A policy could be applied in all states that do the same where CO_2 is stored in former EOR projects. Even the new Wyoming statute that declares the surface owner to own subsurface pore space defines such space as "subsurface space that can be used as storage space for carbon dioxide or other substances."[264] Hence, the future legal scheme for storage of CO_2 in former EOR projects can also honor ownership of minerals, whether depleted by today's production technology or not, in every state.

The IOGCC Task Force Report did not address interim incremental use of EOR projects for CO_2. As a result, its recommendation that the pore space be owned by the surface owner overlooked the potential use of such reservoirs for later withdrawal of two valuable commodities by effectively making the residual minerals legally unrecoverable. This approach thus appears to legislatively

264. H.B. Bill 89, 59th Leg. (Wyo. 2008) (Enrolled Act No. 18) (to be codified as WYO. STAT. ANN. § 34-1-152 (2008). This is "available pore space."

condemn any remaining mineral interest in future recoverable oil without potential compensation to the mineral owner. As this approach has already been adopted in the Wyoming CO_2 storage statute that became effective July 1, 2008, it may create serious unintended legal complications. In light of these issues, the IOGCC may find it appropriate to supplement its report and develop a legislative proposal taking into account the IOGCC's own very successful model unitization statute as a further model statute to encourage the transition from CO_2 EOR to CCS.

IV. OUTLINES OF THE SOLUTION

The above analysis thus suggests the outlines of pragmatic use and judicious modification of the existing legal and regulatory regime that will allow industry participants to begin the transition to geologic storage of CO_2 as part of a carbon emissions reduction regime years before large quantities of CO2 from new power plants begin to enter the marketplace. The key elements are summarized in Figure 4 below and focusing on what is immediately available in our existing EOR legal cadre to aid in developing underground storage opportunities for CO_2 and encouraging the relatively small, albeit significant, changes that could be made to this existing legal regime.

FIGURE 4

Elements of model legal and regulatory regime for transitioning from EOR to CCS:

Purchase and sale issues	
Commercial purchase of anthropogenic CO_2 supply	CO_2 Offtake Agreement with quality specs necessary for EOR, and an economic stabilization clause to address and accommodate unknown changes in future law. Plan for UCC applicability while recognizing may be non-UCC.
Pipeline issues	
Acquisition of pipeline rights-of way	State statute recognizing public necessity of a CO_2 pipeline not only for injection into EOR projects, but also for incremental storage of anthropogenic CO_2, and providing for condemnation on behalf of a CO_2 pipeline serving only EOR projects of the operator. Could be modeled on Louisiana statute passed in 2007 (HB 187/Act 428) which authorizes this action by the Commissioner of Conservation for injection into EOR projects in Louisiana and other states without

	classification as a common carrier that would preclude adapting services to particularized needs of individual CO_2 suppliers or users.
Pipeline operating terms and conditions	Draft quality specifications that are adapted to intended use and reflect applicable UIC restrictions and appropriate indemnifications; operating terms and conditions must reflect principal economic function of the pipeline and allow for negotiated terms to accommodate competing demands of CO_2 suppliers and users
Injection issues	
EPA and State Oil and Gas Commission UIC Regulation for CO2	Authorize conversion of CO_2 UIC Class II wells from use for incidental storage during EOR to incremental storage in same oil and gas bearing formations (whether via proposed EPA Class VI or other designation). Because of their expertise, state oil and gas commissions should retain regulation of CO_2 wells in the event EOR is re-established in future.
Storage site acquisition and unitization issues	
Unitization Agreement for storage	Modify traditional American Petroleum Institute (API) Form unitization agreement to include post-EOR CCS and post-EOR lease extensions for future potential EOR recovery; include grant of storage rights from mineral owners for use of residual pore space
Unit Operating Agreement	Needs to provide for operator to continue operations beyond termination of EOR by incremental storage of CO_2 in the reservoir which storage can be interrupted for EOR operations if technology is available. Will also provide for unit expense and capital to be spent during EOR operations that may provide for equipment upgrades required for future CCS
Oil and Gas Lease Extension and Grant of	Lease extension with the mineral owner for the unitized formation beyond termination of

CO_2 Storage Rights	the EOR project that grants storage rights to the residual pore space for the incremental storage of CO_2. This will allow oil and gas production during suspension of CO_2 storage and restoration of EOR activities, or later withdrawal of CO_2 that results in sales of oil and gas produced.
Carbon Dioxide Storage Perpetual Easement	Easement agreement with the surface owner for use of the available subsurface reservoir pore space and rights of use on the surface.
Compulsory Unitization Statute	Statute that (a) declares (as per the IOGCC Model Statute) that CO_2 is a valuable commodity and that its capture, recovery and geologic storage will benefit the state's citizens and (b) upon proper evidence, authorizes unitization of the leased and un-leased mineral interests and operators in an oil and/or gas reservoir with a minimum approval percentage of the project. Could be modeled on Oklahoma Statute 287.1 et seq., which requires 63% approval of owners and has been upheld and substantiated by over fifty years of case law.
Gas Storage Statute	Statute that allows for sub-surface storage for non-hydrocarbon gases (including CO_2) that allows condemnation of interests after requiring a certain percentage of mineral, surface and leaseholder approvals for the storage facility and ancillary surface equipment. Could be modeled on the Mississippi law which includes storage of compressed air and requires approval of a majority of all interest owners.
Legislation Authorizing Storage and Withdrawal of CO_2	Statute authorizing storage and withdrawal of CO_2 for EOR that can be combined with a gas storage statute and/or a permanent CO_2 storage statute that recognizes the permanence of the elimination of the originating emissions although the CO_2 may be utilized in more than one reservoir for EOR purposes before it is perpetually stored. Could be modeled on Oklahoma statute, which addressed the value of CO_2 as a re-usable source.
Long-term site care, liability, etc.	

Address post-closure funding and responsibility issues	Provide mechanism (per Oklahoma statute and IOGCC Model statute) to ultimately transfer site to entity (state or state-chartered) responsible for post-closure site care and maintenance with access to funding mechanism to pay for ongoing maintenance, monitoring and eventual mitigation.

V. CONCLUSION

This article has examined a broad band of issues which must be reflected upon carefully before addressing a national plan to develop and implement a carbon capture and storage regime to reduce greenhouse gas emissions. Any one of the topics addressed here could qualify as the subject matter of a legal treatise, and thus we apologize to any reader who feels one or another area of interest was not more adequately addressed.

The key conclusion of this review is that existing federal and state legal regimes developed for the EOR business already adequately address many aspects of the needs of such a CCS infrastructure, especially if the early phase of CCS implementation builds on the EOR infrastructure. It also highlights the importance of avoiding the creation of unintended regulatory barriers to incorporating anthropogenic sources of CO_2 into the existing EOR-based infrastructure and transactions. This existing framework can serve as a foundation upon which policy makers can build in order allow the U.S. to implement quickly a carbon emissions reduction program without jeopardizing existing successful energy-related projects.

In sum, rather than crafting detailed regulations for an industry that may not come into existence for years to come, our recommendation is that policy makers focus on incremental use of the existing EOR industry, for example by focusing initially on the injection of CO_2 into the best known and recognized of potential underground reservoirs – those oil and gas reservoirs that have already been identified, described and even unitized for enhanced oil recovery by the injection of CO_2. There will be adequate time to identify more potential sequestration sites that include the deep saline aquifers or coal seams and to draft law for regulating the additional infrastructure that will ultimately be required to make use of those sites. Certainly, Federal government involvement may be required to address the issues of long-term “post-closure” liability for CO_2 injections made for CCS purposes into less-well defined saline aquifer formations. Similarly, where incentive payments are made at the time of initial injection, some mechanism will be required for ensuring the integrity of the incentive regime and reflecting the possibilities for injected CO_2 to be recycled and re-used in EOR activities. But, in the early stages of implementing a carbon emissions reduction regime, the established yet evolving state laws and regulatory rules reflect a deep understanding of the relevant problems and show how the existing state-based legal framework can be utilized for CO_2 storage and how – with some tweaking and refining – it can be amended to allow a progressive transition from incidental injection for EOR to incremental injection for CCS.