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SB 93

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Comments by James R. Staub to the Senate Energy and Telecommunications Committee on Senate Bill No. 93 introduced by R. Erickson; a bill for an act entitled:

"AN ACT REVISING THE COMPOSITION OF THE BOARD OF OIL AND GAS 5 CONSERVATION; AMENDING SECTION 2-15-3303, MCA; AND PROVIDING AN IMMEDIATE EFFECTIVE DATE AND AN APPLICABILITY DATE."

Mr. Chairman, Senators;

This bill proposes to expand the Board of Oil and Gas Conservation from seven to nine members and specifically that the two additional members "must have experience in geology, with one of them being a groundwater hydrogeologist and one being a geochemist." Additionally, that "Members appointed in accordance with subsection (2)(c) may participate in board actions only when the board is acting on applications for the permitting or operation of carbon dioxide injection wells pursuant to Title 82, chapter 11, part 1."

I support changing the Board structure so that geological expertise is resident on the Board in situations where the permitting or operation of carbon dioxide (CO_2) injection wells is under consideration. My reasons for support are related to the changing nature of what CO_2 injection represents. Traditionally, for the last four decades CO_2 injection has been used successfully in Enhanced Oil Recovery (EOR) operations. When CO_2 is injected into an oil reservoir at high pressure it is miscible with the oil (dissolving in the oil) and acts as a solvent, making the oil more fluid. The CO_2 then pushes the fluid oil through the reservoir toward producing wells. Crude oils susceptible to EOR are typically of intermediate to light weight, the reservoirs are of shallow to intermediate depths (650 to 3,000 m), relatively small quantities of CO_2 are utilized, and operations are conducted at relatively small (individual well or field) scales (typically tens to 100's of km^2). At small scales within a petroleum reservoir the impacts of CO_2 injection are reasonably well understood. The object in this situation is resource extraction.

CO_2 injection or sequestration operations, to have a significant impact, must ultimately be conducted at very large scales (1000's of km^2 and larger). In Montana the U.S. Department of Energy indicates that estimated total CO_2 storage resource ranges between about 125 and 1,650 billion metric tons, ranking it 3rd in on-shore capacity behind Texas and Louisiana with Wyoming in 4th position. Only about 2% to 0.015% of estimated total storage capacity in Montana is in existing or depleted petroleum reservoirs. Over 97% to nearly 100% of estimated capacity is found in saline formations or aquifers. In the western U.S. the projected capacity of Montana and Wyoming combined far exceeds the capacity of the surrounding region, and may well represent over 20% of the total on-shore CO_2 sequestration resource capacity nationally. In addition to sequestering CO_2 emissions generated from within Montana, which currently are about 28 million metric tons annually, this massive resource potential positions Montana to become a net CO_2 importer once above ground CO_2 capture technologies prove economically viable and a transportation infrastructure is developed.

Geologic CO_2 storage requires consideration of storage capacity, injectivity, and migration pathways at the 'basin' scale (10,000's of km^2 and larger). The primary large scale geologic structures of interest in Montana with positive closure (i.e. that have the potential to hold large quantities of CO_2) are Kevin Dome, Bowdoin Dome, Porcupine Dome, Popular Dome, and Cedar Creek Anticline. Each of these structures is substantially smaller than 'basin' scale. The saline formations, that represent the CO_2 storage resources, are composed primarily of carbonate rocks (limestones and dolomites) of Devonian to Mississippian age. Some things are known about these resources, such as general knowledge on porosity and permeability, formation water composition, and ideas about unit thickness. This information results in the resource estimates described previously, but this does not address specific questions and/or issues that need to be asked related to the development of both small and large-scale CO_2 injection and storage projects.

At the small end of the spectrum, a storage capacity of million metric tons represents what might be considered the smallest storage size for an individual CO_2 storage project.. For reference, this capacity is approximately equivalent to 12.5 million barrels of petroleum. When we talk about large scale sequestration projects, what are the numbers like? To capture and sequester the CO_2 from a single 1,000 megawatt coal-fired powerplant requires about 8 million metric tons of storage capacity for each year of operation, or about 400 million metric tons over the typical lifetime of a powerplant. Kevin Dome (an area of about 1,800 km^2) has been evaluated in some detail and it is estimated that it has the capacity to hold about 1.4 billion metric tons of additional CO_2. This dome is the location of a natural CO_2 sequestration trap and already contains CO_2 reserves. Simply put, the Kevin Dome structure probably has enough remaining storage capacity to accommodate the CO_2 emissions from about three coal-fired powerplants in the 1,000 megawatt capacity range for their lifetime.

Since the Montana CO_2 storage resource is dominated by saline formations, I'll only briefly address some issues of an operational and geologic nature related to this formation type. For CO_2 sequestration to work, these formations must have two properties: space (porosity, pore volume, or pore space) into which to inject the CO_2 and a trapping mechanism that will retain the CO_2 in that space. What one must consider or realize is that there is no empty pore space in which to inject the CO_2. All the existing space is already filled with a fluid, such as formation water, crude oil, or gas. Therefore, the injection of CO_2 is going to cause the CO_2 to interact with the existing pore-filling fluid or the pore wall (i.e. the formation) in in at least one of several ways; either physically displacing the fluid or dissolving and mixing with the fluids or reacting with the pore walls. In addition, CO_2 at subsurface conditions has a substantially lower density than formation water, so the CO_2 injected into the subsurface is going to displace the formation water and rise buoyantly until it encounters a permeability barrier (seal).

At temperatures and pressures greater than the critical point, CO_2 is supercritical and has densities in the range of 500 to 700 kg/m^3. These pressure and temperature requirements are usually met at depths greater than 800 m (about 2,600 feet) at hydrostatic conditions so CO_2 injection needs to occur below this depth threshold. In order to limit the possibility of CO_2 migrating to pressure and temperature conditions where it would convert from a liquid to a vapor and hence greatly reduce storage capacity, a minimum depth of about 1,000 m (about 3,200 feet) is probably required. A maximum injection depth is probably about 3,000 to 4,000 meters, but this is more related to the range of pipeline pressures.

Several processes, or combinations of processes will trap CO_2 in the subsurface including 1) physical trapping or structural trapping of the buoyant or 'fluid' phase below a seal or within a structure that has vertical and lateral permeability barriers; 2) trapping by capillary forces in the pores of the formation rocks on the trailing edge of the mobile CO_2 plume; 3) solution trapping where the CO_2 is dissolved in formation water, forming solutions such as H_2CO_3 (carbonic acid); 4) dissolution trapping by mixing with resident crude oil; and 5) mineral trapping by precipitation of carbonate mineral phases such as calcite and siderite. As mentioned earlier, the injected CO_2 probably will react with the saline formation/aquifer and seal rocks. The amount of

CO_2 sequestered is going to be dependent on the reactivity of formation materials, chemical composition of the formation water, and reservoir pressure and temperature. The injection of CO_2 into limestone formations may result in a relatively rapid dissolution of carbonate minerals and may result in as much as a 2% increase in porosity. CO_2 sequestration is based on fluid injection on a massive scale, not fluid extraction. The question that constantly will need to be asked is where is the fluid (the CO_2 plume) migrating to?

Seals (confining units, cap rock) are regional strata that inhibit the migration potential of fluids from adjacent strata. Assessment methods for geologic storage of CO_2 are going to require evaluation and prediction of seal integrity. Active fracturing is a potential hazard for CO_2 injection and may occur in a seal where the pore pressure, resulting from either the CO_2 injection rate or the height of the buoyant column of CO_2 exceeds the fracture pressure of the seal. While seal properties are well understood at the physical trap level, there is much less knowledge about seals in a regional sense, for example over the extent of an entire saline formation/aquifer. Although seal integrity in a physical trap can be inferred from the presence of hydrocarbons, there are currently no well-defined criteria to determine the integrity of seals to retain buoyant CO_2 where hydrocarbons are not present.

Pressure increases from CO_2 injection should propagate away from the injection site, possibly extending to and having an effect on flow boundaries (e.g. faults, basin margins, or the updip extent or depth limit of the storage formation). What happens if the flow boundaries are less than 800 m in depth and the CO_2 converts from a liquid to a vapor? Possible hazards from large-scale CO_2 injection may be induced seismicity, contamination of shallow ground water, and the transport of contaminants out of the storage formation.

The issues that I have briefly outlined are but a few of what the Board will need to address in the future related to CO_2 injection and sequestration. This is going to require a difference in perspective. These are issues that must be considered at scales that are substantially larger than the individual (injection) well or even the field scale. Many of these issues are of a hydrologic (fluid flow) and/or geochemical nature and can be best addressed by individuals with appropriate experience. I think there should be geologic oversight capability resident on the Board of Oil and Gas Conservation. Our understanding of subsurface properties from decades of petroleum exploration and development is only partly applicable to problems associated with CO_2 injection and sequestration. Additional expertise is needed. We are moving from oversight of what is primarily a resource extractive industry into what will be a resource injective industry with substantially new issues to consider.

Thank you.

Sources of Data and Information:

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Monea, M., and others, 2009, Considerations for Monitoring, Verification, and Accounting of Geologic Storage of CO_2, *in* Carbon Sequestration and its Role in the Global Carbon Cycle: Geophysical Monograph Series 183, p. 303-315.

Monitoring, Verification, and Accounting of CO_2 Stored in Deep Geologic Formations: National Energy Technology Laboratory, U.S. Department of Energy, published 2009