Technical Issues Related to: Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells

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Executive Summary

A draft rule has been developed by the EPA for their Underground Injection Control (UIC) program to create a new class (Class VI) of injection wells designated solely for the propose of geological sequestration (GS) of CO_2. This document identifies a number of technical issues associated with the rule including:

1. Conflicts that could arise from the use of anthropogenic CO_2 in current CO_2 EOR applications. These include:
    a. The status of benefits derived (tariffs and CO_2 credits) from CO_2 injection,
    b. Reservoir post-closure requirements insofar that long-term storage of CO_2 in an EOR reservoir is materially no different than storage in a GS designated reservoir,
    c. Uncertainties associated with the process of grandfathering Class II EOR wells for subsequent Class VI GS use and,
    d. Lease boundary implications insofar that the pressure front from the CO_2 plume could extend well beyond the lease line, assuming that the reservoir, after depletion, was put in GS service.

    If CO_2 EOR is considered CO_2 GS then several plans not currently required under existing UIC regulations would be required including:
    a. A monitoring and testing plan,
    b. An AoR and corrective action plan, and,
    c. A post-injection site care and site closure plan.
2. Lack of a defined definition for the area of review (AoR). The proposed definition outlines the methodology for computing the AoR without reference to quantitative interpretations of its critical parameters, most notably the term significant pressure decline. In the absence of such information, no unique AoR can be determined. Additional uncertainties also exist with certain aspects of use of multiphase computational mathematical models for determining the AoR, specifically with regard to the boundary conditions.
3. Additional cementing and tubular completion requirements. Specifically, the draft rule proposes three well modifications different from current Class II CO_2 EOR well requirements, namely:
    a. Cementing of the production tubing to the surface,
    b. Installation of an annulus liquid level detector,
    c. Installation of a hydraulically activated down-hole shut-off valve, and,
    d. Use of corrosion resistant materials well. (In the text, the definition of corrosion resistant materials is ill-defined.)

    None of these modifications are in CO_2 EOR use today. (Note that, according to the EPA proposal, if an annulus liquid level indicator is installed, then the need for an annual internal mechanical integrity tests is waived.)

Use of down-hole electrical or hydraulic equipment involves installation of cables or hydraulic lines as well as wellhead modifications. This addition significantly complicates any operations that require pulling of the tubing string, such as would be necessary to conduct the annual external MIT.

4. Corrosion requirements that have been assumed rather than identified. Although no injected gas composition is specified in the report, the injected gas stream is assumed to be corrosive. On the contrary, pipeline operating experience has validated that dry CO_2 is a non-corrosive substance. The decision to accommodate or waive corrosion considerations can only be made when the injected composition is specified.
5. Requirements for both internal and external mechanical integrity tests (MITs). As cited above, if an annulus liquid level indicator is installed, then the need for an annual internal mechanical integrity test is waived.

   However, an annual external mechanical integrity test is required, which could include the use of a tracer survey, a temperature or noise log, a casing inspection log if required by the Director, or an alternative approved by the Administrator and, subsequently, the Director.

   Legally, all UIC injection well owners or operators must demonstrate that their wells have both internal and external mechanical integrity (MI) (40 CFR 146.8). TRRC requires an annular internal MIT based on annulus pressure monitoring only for CO_2 EOR wells.
6. Extensive monitoring of reservoir and site variable during and after CO_2 injection. These include:
   a. CO_2 plume (concentration and pressure)
   b. Pressure Fall-off Test
   c. Ground Water Quality (pH, salinity, heavy metals, organic contaminants, etc.)
   d. Geochemical Data (reservoir)
   e. Surface Air and Soil Gas Data
   f. Injected CO_2 Conditions and MITs

   Although the number of monitoring wells is site-specific, EPA has used a ratio of three monitoring wells for each injection well in its cost estimates.
7. A 50-year post injection site care period that may either be reduced or extended at the discretion of the director. This choice appears to be excessive in light of the facts that:
   a. Hydrocarbon bearing formations have existed over geological time,
   b. CO_2 injection has occurred over decades of operation, and,
   c. Once injection ceases, flows are buoyantly as opposed to advectively driven which occurs on a much more dilated time scale.
8. Reporting frequency requirements are largely unaddressed. Without knowledge of the frequency of reporting, the frequency of testing cannot be identified.

In general, the proposed rule provides significant flexibility for the owner/operator to use appropriate API or ASTM materials and cements for well construction; however, in some sections of the document, the wording is ambiguous, as indicated above.

In formulating their position, the EPA stressed two points, namely that:

1. The proposed rulemaking for GS projects was based on the unique challenges of preventing potential endangerment to USDWs from operations (that is, injection of super-critical CO_2), and,
2. The rule proposes requirements that are intended to provide redundant safeguards.

Given that injection of super-critical CO_2 has been in commercial use for EOR applications since 1972, successfully, it is not clear as to what the unique challenges are. Additionally, it is unclear as to the need for redundancy in systems that are already sufficiently robust in design to handle existing operational requirements.

Lastly, throughout the report, the statement is recurrently made that many of the decisions will be made Director. Clearly, this choice can cut both ways but clearly limits the spectrum of defined actions on behalf of the owner/operator.

EPA Perspective

Basis of New Well

"Today's proposed rulemaking would establish a new class of injection well – Class VI – for GS projects based on the unique challenges of preventing potential endangerment to USDWs from these operations. The Agency invites public comment on the appropriateness of this classification [P47.]"

What are the unique challenges? CO_2 EOR has been commercially done since 1972. The process is identical in nature, if not by intent.

Development and Focus

"The purpose of the GS proposed rule is to mitigate any risk introduced by CO_2 GS activity to the quality, and indirectly the quantity, of current and potential future USDWs. Furthermore, the rule proposes requirements that are intended to provide redundant safeguards [P149]."

Redundancy does not necessarily increase robustness, if the system is robust in its initial design. Has a cost/benefit analysis been performed?

Role of Director

"Director: the person responsible for permitting, implementation, and compliance of the UIC program. For UIC programs administered by EPA, the Director is the EPA Regional Administrator; for UIC programs in Primacy States, the Director is the person responsible for permitting, implementation, and compliance of the State, Territorial, or Tribal UIC program [P10]."

This individual has enormous power regarding the interpretation and enactment of the proposed rule. Seldom is any specific criteria presented upon which decisions are based.

CO_2 EOR

EPA Position on Oil and Gas Reservoir CO_2 GS

"It should also be noted that there are technical challenges associated with GS in depleted oil and gas reservoirs. Injection volumes, operation conditions, and formation pressures for CO_2 injection will differ from those of traditional EOR/EGR operations. The American Petroleum Institute (API) estimates that over 0.6 gigatons (Gt) of CO_2 have been injected for EOR/EGR operations to date and a large percentage of this CO_2 is recovered through production (causing a pressure decrease in the reservoir) (Meyer, 2007). However, DOE estimates that over 90 Gt CO_2 could be geologically sequestered in U.S. oil and gas reservoirs resulting in the potential for reservoir-wide pressure increases [P53]."

Is CO_2 EOR GS?

The proposed EPA regulation establishes geological sequestration (GS) as a distinct technical entity defined as: "The long-term containment of a gaseous, liquid or supercritical carbon dioxide stream in subsurface geologic formations. This term does not apply to its capture or transport [P11]." Additionally, "The requirements in today's proposal, if finalized, would not specifically apply to Class II (CO_2 EOR) injection wells. [P48]".

- Current regulatory thinking envisions that CO_2 EOR would be the recipient of the first volumes of anthropogenicly captured CO_2. Implicitly, this is long term storage. Hence: Is the owner:
  - Entitled to any tariff benefits or CO_2 storage credits associated with injection?
  - Obligated to comply with the complex and inclusive permitting and monitoring requirements outlined in the regulations?
- Assuming that the operator simply chooses to close the facility after oil production ceases, is he obligated to follow the proposed site closure and long-term care requirements? The language in the document appears to recognize that sequestration occurs from the time oil production ceases and the site is, in essence, if not by intent, a long term CO_2 storage facility. Also, are wells required to be plugged and abandonrd as per the EPA proposal?

Grandfathering of Class II Wells

"EPA is proposing to give the Director discretion to carry over or "grandfather" the construction requirements (e.g., permanent, cemented well components) for existing Class I and Class II wells seeking a permit for GS of CO_2, provided he/she is able to make a determination that these wells would not endanger USDWs.

Today's proposal requires that the owner or operator make a demonstration that the well will maintain integrity and stability in a CO_2 rich environment for the life of the GS project. Only the construction requirements would be grandfathered under today's proposal, therefore, Class I or Class II owners or operators seeking to change the purpose of their injection well from Class I or Class II to Class VI would need to meet all other requirements of today's proposed rule (e.g., area of review and site characterization, operating, monitoring, MIT, well plugging, post-injection site care and site closure requirements) [P48.]"

Possible Required Retrofits as per Proposed EPA GS Well Design

1. Down hole automatic shut-off valve with wellhead hydraulics,
2. Annulus liquid level detector,
3. Wellhead corrosion monitoring equipment,
4. Corrosion resistant materials of construction, and,
5. Internal and external MIT tests as per GS Class VI requirements.

Recommendation:

Specify that the decision to grandfather a Class II well is solely based on passing a mechanical integrity test (MIT) without well modification. (The well has been in CO_2 service and can continue to do so.)

New Required Plans

"EPA is proposing today that permit applications for GS sites include several plans not currently required under existing UIC regulations. These plans include a monitoring and testing plan, an AoR and corrective action plan, and a post-injection site care and site closure plan [P112]."

Naturally Occurring CO_2 Reservoirs

When naturally occurring sources of CO_2 (Sheep Mountain, McElmo Dome, Jackson Dome, etc., are depleted, what type of post-closure plan is required, assuming that the operator chooses not to undertake GS?

Area of Review

Pressure Front

"The zone of elevated pressure that is created by the injection of carbon dioxide into the subsurface. For GS projects, the pressure front of a CO_2 plume refers to the zone where there is a pressure differential sufficient to cause the movement of injected fluids or formation fluids into a USDW [P14]."

Non-functional definition. Technically, any pressure differential can cause fluid movement. The extent of movement is controlled by the amount of differential.

Definition and Computation

Definition: "Area of review (AoR): the region surrounding the geologic sequestration project that may be impacted by the injection activity. The area of review is based on computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream [P8]."

"For Class I, II, and III injection wells, Federal UIC regulations require that the AoR be defined as either a fixed radius of ¼ mile surrounding the well (or wells, for an area permit) or an area above the injected fluid and pressure front determined by a computational model. For Class I hazardous waste injection wells, the AoR is defined as a radius of two (2) miles around the well or an area defined based on the calculated cone of pressure influence, whichever is larger [P64]."

"Today's proposal does not specify a period of time over which the AoR delineation models should be run. Rather, available models can predict, based on proposed injection rates and volumes and information about the geologic formations, the ultimate plume movement up to the point the plume movement ceases or pressures in the injection zone sufficiently decline [P69]."

"EPA believes that predicting the complex multi-phase buoyant flow of the CO_2, co-injectates, and compounds that may be mobilized due to injection requires the sophistication of computational models. EPA proposes that the owners or operators of GS wells delineate the AoR for CO_2 GS sites using computational fluid flow models designed for the specific site conditions and injection regime. [P65]."

The foregoing statements provide no information as to "what" constitutes the AoR only "how" it should be computed. How much does the pressure have to decline to be sufficient?

WRI guidelines recommend that,

The MMV area "should include the project footprint (the CO_2 plume and any areas of significantly elevated pressure.)"

How much should pressure be elevated to be significantly elevated? More importantly who makes the decision?

Periodic Reevaluation

"Today's proposal would require that the owner or operator periodically re-evaluate the AoR during the injection operation. Re-evaluations would occur at a minimum fixed frequency, not to exceed 10 years, as agreed upon by the Director [P71.]"

CO_2 EOR Leases and Area of Review

If the area of review (AoR) is based on pressure considerations rather than CO_2 concentration considerations, then several problems may arise for CO_2 EOR operators, namely;

- The AoR may extend well beyond the CO_2 EOR lease boundary and unitization on a regional scale may be required, and,
- There may be poor or limited geological characterization beyond the CO_2 EOR lease boundary, since, presumably, little reserves exist. This could necessitate significant additional site characterization work.

Multiphase Models

Prediction of the Area of Review

EPA believes that predicting the complex multi-phase buoyant flow of the CO_2, co-injectates, and compounds that may be mobilized due to injection requires the sophistication of computational models. EPA proposes that the owners or operators of GS wells delineate the AoR for CO_2 GS sites using computational fluid flow models designed for the specific site conditions and injection regime [P64]."

Technical Concerns

1. What are the criteria for an acceptable model?
2. How are the models validated?
3. What is the minimum set of input parameters for the AoR determination?
4. How frequently must the model be history matched and what constitutes an acceptable history match?
5. What is the physical extent of the modeling area and its boundary conditions so that numerical boundary effects are washed out?

Recommendation

Establish a common test case and solution. Validate all models to a common test case.

Site Characterization

Aquifer Exceptions

"In summary, EPA is soliciting comment on whether CO_2 injection should be allowed into an injection zone above the lowermost USDW, when the Director determines that geologic conditions (e.g., thousands of feet of intervening formations between the injection zone and the overlying and/or underlying USDWs) exist that will prevent fluid movement into adjacent USDWs. EPA is also requesting comments on whether aquifer exemptions should be allowed for the purpose of Class VI injection, and under what conditions should such aquifer exemptions be approved. Finally, EPA seeks comment on whether the Agency should set a minimum injection depth requirement for CO_2 GS, rather than require that such injection take place below the lowermost USDW [P73]."

Cannot assess position. As long as the seals are competent, the position seems justified.

Field Development and Abandonment

Phased Corrective Action (Field Development)

"Today's proposal would give the Director the discretion to allow owners or operators to perform corrective action on an iterative, phased basis over the operational life of a GS project. Prior to injection, the owner or operator would identify all wells penetrating the confining or injection zone within the site AoR. However, the owner or operator may limit pre-injection corrective action to those wells in the portion of the AoR that would be intersected by the CO_2 plume or pressure front during the first years of injection. As the project continues and the plume expands, the owner or operator would continue to perform corrective action on wells further from the well to assure that all wells in the AoR that need corrective action eventually receive it. This approach would ensure that any necessary corrective action is taken in advance of the CO_2 plume and associated area of elevated pressure approaching USDWs [P73]."

Agree. Flexible development approach but how is the original AoR determined?

Partial Field Abandonment

How is partial site closure handled? Since a phased approach can be used for field development (corrective action [P73]), presumably a phase approach can be used for abandonment.

Well Plugging

"EPA is proposing to give owners or operators flexibility in meeting the well plugging requirements by allowing the owner or operator to choose from available materials and tests to carry out the proposed requirements. EPA is not specifying the types of materials or tests that must be used during well plugging because there are a variety of methods that are appropriate and new materials and tests may become available in the future [P115]."

Agree. Flexible approach.

Acid Resistant Cements for Plugging

"Today's proposal would require that the cements and cement additives used in GS wells be appropriate to address long-term injection of CO_2 and assure that the well can maintain integrity throughout the proposed life span of the project, including the post-injection site care period and beyond once the well is permanently plugged. Owners or operators must use corrosion-resistant cement approved by the Director and be able to verify the integrity of the cement using logs or other acceptable methods [P89]."

Agree with first sentence. Implies that if the owner/operator chooses to use corrosion-resistant cement, then it must be approved by Director.

Well Construction and Repair

EPA's General Position

"EPA requires injection wells to be constructed using well materials and cements that can withstand injection of fluids over the anticipated life span of the project [P34]."

Agree, but what is the anticipated life of the project? Who decides what materials can withstand injection of fluids over the anticipated life span of the project?

Corrective Action for Plugging of Abandoned Wells

"Though today's proposal does not dictate specific corrective action methods, it requires that the corrective action methods be appropriate to the CO_2 injection … Today's proposal would require that corrective action for wells in the AoR of GS projects be performed with appropriate corrective action methods such as use of corrosion-resistant cements [P71]".

Agree. Flexible approach with choice left to owner/operator.

Cementing of the Production Casing to Surface

"Due to the buoyancy of CO_2, today's proposal includes enhancements to typical deep well construction procedures to provide additional barriers to CO_2 leakage outside of the injection zone. The proposal would require that surface casing for GS wells be set through the base of the lowermost USDW and cemented to the surface. The long-string casing would be cemented in place along its entire length. GS wells would also be constructed with a packer that is set opposite a cemented interval, at a location approved by the Director.

Disagree. Prefer WRI position that: "The cement should extend from the injection zone to at least an area above the confining zone."

Cement Studies

"Limited results of field studies show clear evidence of reactions between CO_2 and well cement, but do not show such severe corrosion. Cement samples from a well at the Scurry Area Canyon Reef Operators Committee (SACROC) site did not show serious degradation (Carey et al., 2007). In another study, cement samples were collected and analyzed from a CO_2 production well in a natural CO_2 reservoir in Colorado exposed to a CO_2-water environment for 30 years (Crow et al., 2008). The study found considerable reactions between the CO_2 and cement, and CO_2 migration up the wellbore along the cement-formation interface. However, the cement alteration was not significant enough to enable CO_2 migration through the cement itself and the distance of CO_2 migration along the cement-formation interface was very limited. Although the field corrosion looks surprisingly low, these are only limited examples. Laboratory studies are conducted under aggressive chemical conditions in an attempt to mimic the cumulative effects of long-term exposure to CO_2-rich formation fluids. Given the high injection rates, long lifespan, and potential impurities in GS, careful selection of acid-resistant materials and practices may be necessary [P81]."

Agree with position. Does not mandate use of acid-resistant cements but simply indicates that prudent selection be required.

Automatic Down-hole Shut-off Valves

"Traditionally, owners or operators have installed monitoring and shut-off equipment at the wellhead (i.e., at the surface), however, down-hole devices have been used in offshore applications for several years. Today's proposal requires that automatic shut-off valves be installed down-hole in addition to at the surface. This requirement is supported by many participants at the technical workshops and the IOGCC's recommendations [P86]."

Oppose. The technology is not used in current CO_2 EOR applications. Surface monitoring and wellhead automatic shut-off have been quite successful. Requires both well head modification and addition of hydraulic lines.

Annulus Liquid Level Detector

"Therefore, today's proposal would require owners or operators of Class VI GS projects to monitor internal mechanical integrity of their injection wells by continuously monitoring injection pressure, flow rate, and injected volumes, as well as the annular pressure and fluid volume to assure that no anomalies occur that may indicate an internal leak. EPA requests comment on the practicability of this requirement [P97]."

Undecided. Although this technology is not used in current CO_2 EOR applications, installation of the equipment results in a waiving of the internal mechanical integrity test. Requires both well head modification and addition of electrical or pneumatic line.

Horizontal Wells

"EPA seeks comment on the merits of horizontal well drilling techniques for GS wells and the applicability of well construction requirements discussed in this proposal [P81]."

Accept position. See no technical reason why horizontal wells should be excluded, in general, although application requires consideration of site specific characteristics.

Corrosion and Metallurgy

Carbon Dioxide Stream Definition

"Broadly defined to be carbon dioxide (CO_2) stream: carbon dioxide that has been captured from an emission source (e.g., a power plant), plus incidental associated substances derived from the source materials and the capture process, and any substances added to the stream to enable or improve the injection process. This subpart does not apply to any carbon dioxide stream that meets the definition of a hazardous waste under 40 CFR Part 261, [P8]"

No composition specifics. Therefore corrosivity cannot be determined.

Assumption of Corrosivity

"As previously discussed, internal MI testing is designed to evaluate the condition of internal well components. The evaluation is typically accomplished with an annual pressure test. However, due to the nature of the GS injection stream, corrosivity must be considered when planning for MITs in GS projects. Studies conducted by EPA of previous MIT results suggest that wells injecting corrosive fluids fail MITs at rates 2 to 3 times higher than those that inject non-corrosive fluids. Thus, a more corrosive injectate is a potential risk factor for MIT failure [P97]."

Invalid position without specified composition.

Corrosion Resistant Well Materials

"The use of corrosion-resistant materials is crucial to the success of long-term GS operations. UIC program experience, industry experience, and stakeholder input suggest that appropriate materials are available. Today's proposal does not specify materials that may be used, rather, proposes providing the owner or operator with the flexibility to choose, as long as the materials used in GS wells are corrosion-resistant and meet or exceed standards developed for such materials by API or ASTM International, or comparable standards approved by the Director. Well materials must be compatible with injected fluids, including any co-injected impurities or additives, throughout the life of the project, and be appropriate for the well's depth, the size of the well bore, and the lithology of injection and confining zones [P82]. "

Until the injected gas composition is specified, it is impossible to determine if corrosion resistant materials are required. Does the casing have to be corrosion resistant? (Need additional information and clarification.)

Corrosion Monitoring

"CO_2 reacts with water to become acidic, potentially accelerating corrosion of well materials. The CO_2 stream for a GS project may also contain small volumes of impurities that could be corrosive. Thus, EPA is proposing to require corrosion monitoring for GS wells. Corrosion monitoring is further discussed in the monitoring and testing section of this preamble [P89]."

"EPA also proposes that owners or operators would monitor well materials for signs of corrosion, such as loss of mass, thickness, cracking, or pitting [P101]."

As above.

Operations

Maximum Injection Pressure

"Today's proposal would require an injection pressure limitation similar to existing UIC Class I deep well requirements. … Under this proposal, during injection, the pressure in the injection zone must not exceed 90 percent of the fracture pressure of the injection zone. Calculation of fracture pressure is fundamental to evaluating the appropriateness of the site. The 90 percent requirement, suggested by permit writers and IOGCC, provides an added margin of safety in the well operation [P84]."

WRI Position. "Injection pressures should be determined by well tests. Injection formation parting pressure should not be restricted by a regulatory framework but may be adopted as a best practice for early projects.

Prefer IOGCC position. I do not fully understand how WRI's position impacts fracture propagation in the confining zone.

Hydraulic Fracturing

"EPA is requesting comment on the extent and scope to which hydraulic fracturing should be allowed during GS injection, and whether the use of fracturing for the purposes of well stimulation is appropriate. EPA is also requesting information to better qualify the use of fracturing for GS injection in specific geologic settings and rock formation lithologies [P85]."

Based on the success of hydraulic fracturing in oil and gas operations, similar technology should be used in GS applications.

Tracers

"Today's proposal allows Directors' discretion on whether to require the use of tracers, and if so, what types of tracers. EPA seeks comment on the use of tracers in CO_2 GS operations, and any potential impact of tracers on human health or ecosystems as they relate to USDWs [P96]."

Agree, provided appropriate materials can be identified.

Internal and External Mechanical Integrity Tests (MITs)

"Therefore, today's proposal would require owners or operators of Class VI GS projects to monitor internal mechanical integrity of their injection wells by continuously monitoring injection pressure, flow rate, and injected volumes, as well as the annular pressure and fluid volume to assure that no anomalies occur that may indicate an internal leak. EPA requests comment on the practicability of this requirement.

As mentioned above, external mechanical integrity testing is used to determine the absence of fluid leaks behind the long string casing. Instead of requiring external MI to be demonstrated every five years (which is typical for other types of deep injection wells), today's proposal would require owners or operators of CO_2 wells to demonstrate injection well external mechanical integrity at least once annually. This increase in testing frequency (from once every five years to once a year) is justifiable for the protection of USDWs given the potential corrosive effects on injection well components (steel casing and cement) that are exposed to the GS stream and the buoyant nature of the injected fluid that tends to force it upward toward USDWs.

Today's proposal does not change the existing allowable methods for demonstrating external MI in deep injection wells. They would include the use of a tracer survey, a temperature or noise log, a casing inspection log if required by the Director, or an alternative approved by the Administrator and, subsequently, the Director. Today's proposal would also provide the Director with the discretion to request additional tests.

This proposed requirement would eliminate the necessity of conducting other periodic internal MITs. However, today's proposal would provide the Director with the discretion to request any other additional tests necessary to ensure the protection of USDWs [P 97-8]."

Undecided. Current monitoring techniques have proven to be sufficient to guarantee well integrity. However, installation of an annulus liquid level sensor would eliminate the need for an annual internal MIT. Need additional information as to justification for annual external integrity tests and the specifics of external integrity tests in general.

Monitoring, Measurement and Validation (MMV)

Wide Spectrum Approach

It appears as though the selection of monitoring variables was based on the widest possible spectrum available. No consideration appears to have been given to the costs/benefits associated with acquiring the information.

With the exception of the injected CO_2 conditions, no frequency or required analysis is presented for the other variables. Since the AoR needs to be updated on a 10 year basis, this probably represents the minimum timeframe for data acquisition.

CO_2 Plume

"Under today's proposal, owners or operators would be required to track the subsurface extent of the CO_2 plume and pressure front using pressure gauges in the first formation overlying the confining zone or using indirect geophysical techniques (e.g., seismic, electrical, gravity, or electromagnetic surveys) or other down-hole CO_2 detection tools, monitor for geochemical changes in subsurface formations, and if directed, monitor at the surface. Today's proposal would also require owners or operators to monitor ground water quality and geochemical changes above the confining system. The results of this monitoring would be compared to baseline geochemical data to identify changes that may indicate unacceptable movement of CO_2 or formation fluids [P102]."

What is the monitoring frequency?

Ground Water

"A monitoring program for a GS project should be designed to detect changes in ground water quality and track the extent of the CO_2 plume and area of elevated pressure [P100]."

What spatial density is required for the monitoring wells?

Pressure Fall-off Test

"Today's proposal would require that owners or operators perform a pressure fall-off test at least once every five years. Pressure fall-off tests are designed to ensure that reservoir injection pressures are tracking to predicted pressures and modeling input. They may be used in project siting and AoR calculations. Results of pressure fall-off tests may indicate mischaracterization of the site specific geology and potentially unidentified leakage pathways [P103]."

Unfamiliar with the results derived from the tests. However, if bottom hole shut-in pressure is measured, isn't this sufficient for model validation?

Geochemical Data

"Direct geochemical monitoring is an important part of a monitoring program. Temperature, salinity, and pH should be monitored, as these parameters provide basic information for understanding water and gas geochemistry [P104]."

Surface Air and Soil Gas Data

"Under today's proposal, owners or operators could, at the Director's discretion, be required to conduct surface air monitoring and/or soil gas monitoring in the AoR [P109]."

Injected CO_2 Conditions and MITs

"EPA proposes that owners and operators report semi-annually on the characteristics of injection fluids, injection pressure, flow rate, temperature, volume and annular pressure, and on the results of MITs, ground water monitoring, and any required atmospheric/soil gas monitoring [P11]1."

Monitoring Wells

"Monitoring within the confining zone for pressure, pH, salinity, or the presence of dissolved minerals, heavy metals, or organic contaminants requires direct access to the subsurface via monitoring wells. Wells installed for this purpose would be strategically placed in areas predicted to overlie the eventual CO_2 plume and area of elevated pressure. Well number and placement would be based on project specific information such as injection rate and volume, site specific geology, baseline geochemical data, and the presence of artificial penetrations [P103]."

"Third, the Agency assumes three monitoring wells per injection well for the purpose of estimating national costs; however, the Agency recognizes that operators and primacy agency Directors may choose more or fewer monitoring wells depending on project site characteristics. [P150]."

Although the number of monitoring wells is uncertain, this cost will be a significant part of the MMV program.

Post-Injection Site Care

Duration

"EPA is also proposing that a combination of a fixed timeframe and performance standard be used to determine the duration of the post-injection site care period [P116]."

While 10 years may be within the timeframe suggested in some studies (IOGCC), there are circumstances under which the potential risks of endangering USDWs will not decline within that timeframe given that stabilization may continue for several decades (USEPA, 2008d). Also, a 30-year timeframe can be appropriate for the types of fluids typically injected under the UIC Program (i.e., fluids that are liquids at standard pressure and temperature). Longer timeframes may be more appropriate for GS wells, because the fluid is likely to be stored in a supercritical phase, the plume for a full-scale GS project will likely be large, and substantial pressure increases will likely be observed during operation [P120]."

EPA considers that a 50-year timeframe represents a reasonable mid-point for the default time frame, which may be modified with the approval of the Director based on a demonstration (by the owner or operator) using monitoring and modeling, that the injected CO_2 will not endanger [P150]."

Comment

1. Existence of CO_2 in the super-critical state is immaterial to storage considerations. CO_2 EOR is shipped and injected at super-critical conditions. It's simply a consequence of operating at a pressure above the critical point. Fracture pressure is the issue much the same as in natural gas storage.
2. 50 years of monitoring is inapplicable to oil and gas reservoirs. The integrity of the reservoirs has been established over geological time (millions of years) as well as decades of production operations.
3. Once injection ceases pressure declines. Fluid movement is curtailed except by buoyantly driven, as opposed to advectively driven, flows that are slow and limited, since the fluid is already distributed at the top of the reservoir.

Recommendation

Follow World Resources Institute (WRI) guidelines using performance base criteria.

EPA seeks comment on whether the Director should be allowed to shorten the timeframe based on performance information, and whether EPA should require a shorter or longer post injection period if data suggests the time frame should be adjusted.

Permits, Plans and Processes

Well Permit Duration

"Implementation of the AoR and corrective action plan as described in today's proposal would involve periodic re-evaluation of site data, status of corrective action, monitoring results and modification of operating parameters, as needed. …

Therefore, EPA proposes that Class VI injection well permits would be issued for the operating life of the GS project including the post-injection site care period. EPA seeks comment on the merits of this approach [P140]."

Post-Injection Site Care

"Today's proposal would also require that owners or operators 1) develop a post-injection site care and closure plan, 2) monitor the site following cessation of the injection activity, and 3) plug all monitoring wells in a manner which prevents movement of injection or formation fluids that could endanger a USDW.

Activities that would be required in the post-injection site care and site closure plan include: 1) record of the pressure differential between pre-injection and anticipated post-injection pressures in the injection zone; 2) predicted position of the plume and associated pressure front at the time the site is closed; 3) description of post-injection monitoring location(s), methods, and proposed frequency of monitoring; and 4) schedule for submitting post-injection site care and monitoring results to the Director.

Upon permanent cessation of injection, the owner or operator would either submit an amended post-injection site care and site closure or demonstrate to the Director through monitoring and modeling results that no amendment to the plan is needed. Owners or operators would also be required to use any other information deemed necessary by the Director to make this demonstration.

The post-injection site care and site closure plan would include a description of the monitoring that will occur after injection ceases. The owner or operator would monitor the site to show the position of the CO_2 plume and pressure front and demonstrate that USDWs are not being endangered. A record of the pressures in the injection formation and surrounding areas as well as the pressure decay rate can help the owner or operator determine that the injected fluid does not pose endangerment to USDWs [P118]."

Reporting and Record Keeping

Well Plugging, Post-injection Site Care and Site Closure

"EPA proposes that owners or operators notify the Director at least 60 days prior, or at a Director-determined time, of their intent to plug the well and of any updates to the post-injection site care and site closure plan. After the well is plugged, owners and operators would submit a well plugging report stating that the well was plugged in accordance with the approved post-injection site care and site closure plan or specify the differences between the plan and the actual well plugging. During the post-injection site care (monitoring) period, owners or operators would report periodically on the results of monitoring. At the end of the post-injection site care period, owners or operators would submit a site closure report, along with a non-endangerment demonstration showing that conditions within the subsurface indicate that no additional monitoring is necessary to assure that there is no endangerment to USDWs associated with the injection [P113]."

How periodically?

Proposed Annual Report

"In addition to the above recordkeeping and reporting requirements, EPA considered a requirement for owners or operators of GS sites to provide an annual report during the lifetime of the project, including the post-injection period, regarding the GS operation. This report would describe the status of the operation, any new data about the site including operational and monitoring data, new GS operations, or other activities that may affect the plume movement, any non-compliance, and knowledge gained on GS technology that could contribute to the state of the science on GS. This requirement would address the unique and large-scale nature of CO_2 GS operations, provide the public with information regarding the operation, and facilitate information transfer about GS technology. Although EPA has not included a requirement for this report in today's proposal, EPA seeks comment regarding the necessity for such an annual report [P115]."

Information Retention

"Under today's proposal, owners and operators would also be required to maintain recordkeeping and reporting information for the duration of the project, as well as three years after site closure (following the post-injection site care period); and to keep their most recent plugging and abandonment report for one year following site closure [P113]."