United States Environmental Protection Agency

Underground Injection Control (UIC) Class VI Program

Public Comments Received on the *Underground Injection Control Program Class VI Well Construction Guidance*

May 2012

Disclaimer

Personal information (i.e. phone numbers and email addresses) has been removed from correspondence.

Office of Water (4606M)
EPA 816-R-11-021
May 2012
http://water.epa.gov/drink/

Overall Comments:

The Railroad Commission of Texas (RRC) wishes to foster the means of safe, efficient, and effective capture and storage of carbon dioxide gas, and thus offers comment to the four U.S. Environmental Protection Agency (EPA) draft guidance documents on this subject, dated March 2011. The RRC commented on the Class VI rules (40 CFR 146 Subpart H) when they were initially published in 2009, and based on our own experience, the rules are more stringent than necessary. We believe that the rules as finalized may act as a *deterrent* to their stated purpose as described by EPA in the opening paragraph of their preamble to these proposed rules where geologic storage of CO_2 is proposed "to reduce CO_2 emissions to the atmosphere." Although the rules as recently promulgated appear to be more stringent than are necessary, their proposed means of implementation as described in the four draft guidance documents referenced above, are of great interest and importance to the RRC.

The draft documents appear to be based on sound science and should be potentially useful. However, the RRC is concerned that these guidance documents remain as guidance, and that the methods described therein do not become *de facto* rule. At least some of the methods described would not be necessary in order to comply with the rules. Other described methods would not apply to many sites. We, therefore, strongly encourage EPA to follow the guidance document disclaimer that states, in part: "Therefore, this document does not substitute for those provisions or regulations, nor is it a regulation itself, so it does not impose legally-binding requirements on EPA, states, or the regulated community." Flexibility on site-specific issues, and future considerations for innovative approaches, remain of paramount importance to the RRC.

The RRC recommends that EPA revise the disclaimer language (for example, on Page ii of "Geologic Sequestration of Carbon Dioxide: Draft Underground Injection Control (UIC) Program Class VI Well Project Plan Development Guidance for Owners and Operators," dated March of 2011, second paragraph, third through fifth sentences) to read:

> "This is done to provide information and suggestions that may be helpful for implementation efforts, Such suggestions are prefaced by "may" or "should," <u>or include phrases such as "EPA recommends,"</u> and are to be considered advisory. They are not required elements of the rule."

In addition, the definitions should be consistent in each guidance document. For the terms that are defined in the rules, the RRC recommends that EPA use the exact language of the rule and include a reference to the rule to distinguish which definitions are in the rule and which are not.

The RRC offers the following comments on each individual guidance document.

I. Comments on EPA's document titled "Geologic Sequestration of Carbon Dioxide: Draft Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance for Owners and Operators," dated March 2011.

The RRC suggests that a unit conversion table, similar to that included on Page xvi of the "Draft Underground Injection Control (UIC) Program Class VI Well Site Characterization Guidance for Owners and Operators" would be helpful.

• Page 2, second complete paragraph, Line 9:

The RRC recommends the following revision: "The purpose of Class VI injection well AoR reevaluation is to ensure that site monitoring data is used to update modeling results, and that the AoR delineation reflects any changes [~~changed~~] in operational conditions."

• Pages 11 – 13, Table 2-1:

The RRC recommends that units be included for the parameters listed as part of the column "Parameter" or the column "Description."

• Page 32, first three lines:

The sentence reads: "The pressure front, as described below, is the extent of pressure increase of sufficient magnitude to force fluids from the injection zone into the formation matrix of a USDW through a hypothetical open conduit." The existing rule definition of "pressure front" does not include mention of a "hypothetical open conduit."

The RRC recommends that, when the guidance document modified a term defined in the rule, the EPA add a clarification or disclaimer.

• Page 32, First complete paragraph:

"Box 3-2 of this guidance document provides an example of an AoR delineation based on computational modeling results, including the calculation of the threshold pressure that defines the 'pressure front.' The determination of the pressure front in Box-3-2 (Step 2) is consistent with existing standard practices for other well classes of the UIC program (e.g., Thornhill et al., 1982; US EPA, 2002), and is applicable to any Class VI injection well for which, prior to injection, the injection zone is not over-pressurized compared to the lowermost USDW (i.e., the injection zone has a lower or equal hydraulic head as compared to the lowermost USDW). <u>EPA anticipates that the methodology in Box 3-2 will be applicable to most GS projects, which will likely not occur in over-pressurized formations; however, the example is not applicable to projects with over-pressurized injection zones because the resulting calculated AoR in this case could be infinite in extent.</u> Owner/operators of potential Class VI injection wells planned to be constructed in over-pressurized formations are encouraged to consult the UIC Program Director regarding the appropriate determination of the pressure front and resulting AoR delineation. In all cases, the AoR must encompass the entire area for which the project may cause an endangerment of USDWs [§146.84 (a)]." [Underlining added.]

The RRC anticipates that many of the Class VI operations will occur in over-pressured formations. Under-pressured injection formations are much more likely to occur as part a Class II enhanced recovery project, at least in Texas. While we agree that the example is not applicable to projects with over-pressured injection zones and that the resulting AoR would be infinite, with another equation, and appropriate assumptions, the resulting calculated AoR may not be infinite. This example will apply to very few Class VI sites in Texas.

Therefore, the RRC recommends the following language:

"Box 3-2 of this guidance document provides an example of an AoR delineation based on computational modeling results, including the calculation of the threshold pressure that defines the 'pressure front.' The determination of the pressure front in Box-3-2 (Step 2) is consistent with existing standard practices for other well classes of the UIC program (e.g., Thornhill et al., 1982; US EPA, 2002), and is applicable to any Class VI injection well for which, prior to injection, the injection zone is not over-pressurized compared to the lowermost USDW (i.e., the injection zone has a lower or equal hydraulic head as compared to the lowermost USDW). EPA anticipates that the methodology in Box 3-2 will be applicable to some [~~most~~] GS projects[~~, which will likely not occur in over pressurized formations~~]; however, the example is not applicable to projects with over-pressurized injection zones because the resulting calculated AoR in this case could be infinite in extent, depending on the equations and/or methodology used. Owner/operators of potential Class VI injection wells planned to be constructed in over-pressurized formations are encouraged to consult the UIC Program Director regarding the appropriate determination of the pressure front and resulting AoR delineation. In all cases, the AoR must encompass the entire area for which the project may cause an endangerment of USDWs [§146.84 (a)]."

The RRC certainly agrees that consultation with the UIC director on this issue is appropriate, as model assumptions of greater initial pressure in the USDW than the injection zone may not apply to many sites. Other modeling methods may be more accurate.

• Page 41, in the first complete paragraph, the first two sentences read: "The potential also exists for more recently constructed wells to have been decommissioned improperly. For example, wells may have been plugged with debris and trash rather than with the proper cement."

The last sentence, which implies that recently plugged and abandoned wells are likely to have been plugged with "debris and trash," is not correct. For decades- particularly since the publication of the API Standards in 1952, state regulations have required that wells be appropriately plugged with the cement. The RRC recommends that EPA delete the second sentence.

• Page 68, in the first complete paragraph, there are two typos in the second sentence:

"In addition, EPA recommends that the model calibration process and final AoR delineation results be presented in detail as part of the submission , with adjusted input parameter values listed, graphs comparing observed and modeled values of carbon dioxide migration and fluid pressure, and model results showing carbon dioxide and pressure front migration over time included. ."

II. Comments on EPA's document titled "Geologic Sequestration of Carbon Dioxide: Draft Underground Injection Control (UIC) Program Class VI Well Site Characterization Guidance for Owners and Operators."

• Page 17, second paragraph:

The final sentence of the second paragraph uses the term "plunge," when "dip" is the term most commonly used in geologic literature. The RRC recommends the following revision: "Furthermore, while cross-sections are normally presented perpendicular to the ground surface, only cross-sections oriented perpendicular to the <u>dip</u> [~~plunge~~] of the units will show the true bedding thickness (Groshong, 2006)."

• Page 17, fifth paragraph, fifth sentence:

The RRC recommends the following revision: "Common methods include along <u>dip</u> [plunge], with structural contours, and within dip domains." Also, the RRC is unsure of the meaning of "dip domains" and recommends that EPA clarify or use a different term.

• Page 44, fourth complete paragraph, second sentence:

The RRC recommends the following revision: "Pressure changes during drawdown tests [~~during~~] can be analyzed quantitatively or, if multiple wells are available, variable flow test analysis can be used to determine permeability provided that the reservoir pressure, flowing bottom- hole pressure, flow rates, and the total time of the test are known (Smolen, 1992a; Matthews and Russell, 1967)."

• Page 49, first paragraph, first four sentences:

"The GS Rule requires baseline geochemical information on subsurface formations [§146.82(a)(6)]. Any general geochemical information available for the region should have been obtained as part of the initial geologic characterization. See Section 2 of this guidance document, above, for more information. More specific geochemical information is required on the injection zone as part of a planned formation testing program at a proposed Class VI injection well site [§146.82(a)(8)]."

The fourth sentence appears to quote or reference §146.82(a)(8). This part of the rule is not very "specific." It reads "(8) Proposed pre-operational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone(s) and confining zone(s) and that meets the requirements at §146.87." Section 146.87(c) includes one reference to specific "geochemical information," including fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s).

Therefore, the RRC recommends the following revisions: "More specific geochemical information is required on the injection zone <u>prior to injection well operation</u> [§146.87(c)] [~~as part of a planned formation testing program at a proposed Class VI injection well site~~] [~~§146.82(a)(8)~~]."

Or

"<u>Fluid temperature, pH, conductivity, reservoir pressure, and static fluid level are</u> [~~More specific geochemical information is~~] required on the injection zone as part of <u>pre-</u>

injection testing [§146.87(c)] [~~a planned formation testing program at a proposed Class VI injection well site [§146.82(a)(8)]~~]."

• Page 62, Figure 3-18 (failure plots):

Figure 3-18 does not define "C" nor does it include the criteria for its numerical values of 0 and 4. In addition, "μ" is not defined. If "μ" is the coefficient of friction as discussed on page 59, the RRC recommends that EPA clarify.

• Page 81, Figure 3-24 (ERT array):

The RRC recommends that EPA include better definition of terms and symbols in Figure 3-24. The Distributed Thermal Sensor (DTS) is defined below the figure, but not depicted in the diagram. Only the DTS Cable is labeled, but not the tool, unless the tool is denoted by "★" in the diagram. If so, this needs to be indicated below the diagram. If not, "DST" should be labeled on the diagram and "★" should be defined.

• Page 106, first paragraph, second sentence:

"Molecular diffusion is defined as the net transport of a molecule in a liquid or gas medium as a result of intermolecular collisions and driven by a gradient through the medium such as temperature, temperature, or concentration (Tucker and Nelken, 1990)."

The word "temperature" is listed twice. The RRC recommends that EPA consider replacing one of the terms "temperature" with "pressure."

• Page 114, second paragraph, second sentence: "This section describes the data needed to make the required demonstration that the confining zone will not allow migration of carbon dioxide; either through interconnected pore spaces across the thickness of the seal or by allowing migration of carbon dioxide through the confining zone along faults or fractures."

Geologic migration through interconnected pore spaces across the thickness of the seal may well occur, even in low permeability strata, but hopefully in a timeframe measured in at least thousands of years, if not millions. The RRC suggests that the sentence be modified as follows: "This section describes the data needed to make the required demonstration that the confining zone will not allow migration of carbon dioxide <u>beyond its strategraphic and structural boundaries for at least thousands of years;</u> either through the confining zone along faults or fractures."

• Page 118, Figure 3-37:

The RRC recommends that EPA define the term "Shale Gouge Ratio (SGR)" on this figure or reference the definition given later o page 121.

• Page 127, third paragraph, next to last sentence: "Two of the more sophisticated analyses that are required for a proposed Class VI injection well are the determination of storage capacity and the demonstration of confining zone integrity."

The RRC was unable to find specific reference in existing rule that determination of storage capacity is required. A rule citation seems appropriate for this parameter if it exists as a rule requirement. Otherwise, a statement that determination of storage capacity is implicit would, in our thinking, be a better choice of words. Also, a rule citation for demonstration of confining zone integrity would seem appropriate. Citing §146.82 (a)(3), as well as §146.83(a)(2) would be preferred in this context.

Thus the RRC recommends the following language: "Multiple sophisticated analyses should be needed for a proposed Class VI injection well. One is determination of storage capacity, which is implicit for successful evaluation of a Class VI permit. Another is a demonstration of confining zone integrity as stated under §146.82 (a)(3), and §146.83(a)(2)."

III. Comments on EPA's document titled "Geologic Sequestration of Carbon Dioxide: "Draft Underground Injection Control (UIC) Program Class VI Well Project Plan Development Guidance for Owners and Operators."

- Page 13, third paragraph, first sentence:

The RRC recommends the following revision: "In the event that the owner or operator determines that revisions to the model are necessary, the plan must discuss how the newly available data will be used to revise the model and AoR delineation <u>(§146.xx)</u>.

- Page 15, first paragraph (under *Corrective Action Schedule*), final sentence:

Specific dates would not be known when such plans are drafted. This wording is not realistic, as field operations and subcontractor availability are not predictable. The RRC recommends the following revisions: "However, for improperly plugged wells that will need corrective action prior to injection, and whenever practical, EPA recommends that the AoR and Corrective Action Plan include <u>approximate timeframes and commitment to appropriate notification</u> [~~specific dates~~] for performing corrective action, in order to give the UIC Program Director an opportunity to witness the corrective plugging activities."

- Page 22, last paragraph, second sentence:

In accordance with the guidance disclaimer, the RRC recommends the addition of a citation: "Some of the elements of the Testing and Monitoring Plan are highly site-specific (e.g., monitoring well placement) and will require detailed descriptions of how these specific factors were identified and considered in developing the plan <u>(§146.xx)</u>."

- Page 25, fourth paragraph, second sentence:

In accordance with the guidance disclaimer, the RRC recommends the following revisions: "See the *Draft UIC Program Class VI Well Site Characterization Guidance* for <u>suggestion</u> [~~details~~] about what information must be generated as part of the baseline data collection required under §146.82(a)."

- Page 27, first complete paragraph, third sentence and following bullets:

In accord with the guidance disclaimer, the RRC recommends that EPA add the appropriate citations as follows: The Testing and Monitoring Plan must describe how the

following information has been considered in determining appropriate monitoring well placement:
• The depth, thickness, and permeability of the injection and confining zones, USDWs, and any relevant additional zones (§146.xx);
• The size and shape of the AoR, based on the current delineation (§146.90 (g));
• The presence of artificial penetrations (§146.90 (d)(1)); and
• The planned injection rates and volumes (§146.90 (d)(1)).

Also, RRC recommends the addition of a rule citation for the first bullet under §146.90 wherein the Testing and Monitoring Plan are described under rule.

● Page 29, third paragraph, first part of the third sentence:

In accord with the guidance disclaimer, the RRC recommends that EPA add the citation as follows: "However, because a request for using alternative methods other than those currently approved by EPA requires an additional EPA approval process to become acceptable and the eventual publication of the alternative method approval in the *Federal Register* (§146.89 (e)),………"

● Page 32, first complete paragraph, last sentence:

Because §146.90 states in part that the Director *may* require this monitoring, the sentence needs the conditional clause: "Compliance with these Part 98 requirements is considered a condition of the Class VI permit [§146.90(h)(3)] if surface air/gas monitoring is required by the UIC Program Director."

● Page 40, first paragraph of Section 5.0:

The RRC believes that the word "extensive" is not appropriate and recommends the following revisions: "Following cessation of injection activities, Class VI injection well owners or operators must conduct appropriate [~~extensive~~] site monitoring until the movement of the carbon dioxide plume and pressure front have ceased and the injectate does not pose a risk to USDWs."

● Page 43, second paragraph of Section 5.1.5, first sentence:

The applicable rule (appropriately cited in the previous paragraph of the draft guidance, page 43) is §146.93(a)(2)(v), which does not include "specifics." In addition, three of the "specifics" listed are not included anywhere in the new rules: "site-specific chemical processes that will result in carbon dioxide trapping; the predicted rate of carbon dioxide trapping; …and laboratory analyses or studies to verify the information on trapping." The RRC was unable to find where these three are listed as criteria or objectives in the rules. At best, these three are implied and may be useful, but do not otherwise appear to be required by rule. The others listed appear to be required under §146.82 and §146.83, but are not stated as criteria to be considered under §146.93.

Therefore, in accord with the guidance disclaimer, the RRC recommends the following revisions: "The demonstration should [~~must~~] be based on site-specific information, including the results of site-specific computational modeling; the predicted timeframe for pressure decline; the predicted rate of carbon dioxide plume migration; site-specific chemical processes that will result in carbon dioxide trapping; the predicted rate of carbon dioxide trapping; characterization of the confining zone(s); laboratory analyses or studies to verify the information on trapping; the presence of potential conduits for fluid movement and the quality of abandoned well plugs within the AoR; the distance between the injection zone and USDWs above and/or below the injection zone; and any additional site-specific factors determined by the UIC Program Director."

• Appendices A through F appear to be helpful suggestions in drafting the plans required under rule.

IV. Comments on EPA's document titled "Geologic Sequestration of Carbon Dioxide: "Draft Underground Injection Control (UIC) Program Class VI Well Construction Guidance for Owners and Operators."

The RRC recommends that this guidance document be reviewed by an expert in well construction and completion.

• Page 1, second paragraph, first three sentences:

The draft guidance reads as follows: "As carbon dioxide injection is different than other injection previously regulated by the UIC Program, the GS Rule sets requirements specific to carbon dioxide. Because carbon dioxide is less dense than most subsurface fluids, it is buoyant and will tend to migrate to the top of the injection zone. Carbon dioxide also has the potential to be corrosive when mixed with water."

The first sentence is not true because it ignores Class II operations where CO_2 has been injected since at least 1972. The remaining sentences as drafted could be taken to describe Class II operations as well. However, Class VI activities are different from Class II CO_2 injection insofar as injection rates and pressures for Class VI are likely to be greater than Class II. And, geologic structure may be different as well.

Therefore, the RRC recommends the following revision: <u>Carbon dioxide injection in Class VI wells shares similarities with carbon dioxide injection in Class II wells (described below), but also may have differences. Differences include faster injection rates as Class VI wells are likely to pump more carbon dioxide into rocks than Class II wells. Also, Class II sites are known to have geologic structures that trap hydrocarbons and thus carbon dioxide, whereas less may be known about geologic structure at a Class VI wellsite. With respect to Class VI sites, due to possibly greater rates, greater attention may be necessary to carbon dioxide,</u> because carbon dioxide is less dense than most subsurface fluids, <u>and</u> it is buoyant and will tend to migrate to the top of the injection zone. Carbon dioxide also has the potential to be corrosive when mixed with water.

• Page 4, fourth paragraph, first sentence:

The RRC was unable to find this definition of "internal mechanical integrity" in the rules. In accord with the guidance disclaimer, the RRC recommends that EPA reference the citation to the definition or modify the sentence as follows: "Internal mechanical integrity is defined <u>in this document</u> [~~the GS rule~~] as the absence of significant leaks in the casing, tubing, or packer."

• Page 4, fifth paragraph, first sentence:

The RRC was unable to find this definition of "external mechanical integrity" in the GS rule. Thus, in accord with the guidance disclaimer, the RRC recommends that EPA reference the citation to the definition or modify the sentence as follows: "External mechanical integrity is defined in this document [~~by the GS rule~~] as the absence of significant leakage outside of the casing.

• Page 4, fifth paragraph, fourth sentence:

The RRC recommends the following revisions: "Properly emplaced cement should both prevent fluid movement by sealing the annular space between the casing and the formation, and protect the well casing from stress and corrosion."

• Page 6, first paragraph, last sentence:

The RRC recommends the following revisions: "Therefore, the casing must be manufactured of materials that are [~~made out of a material that is~~] compatible with fluids with which it might come into contact [40 CFR §146.86(b)(1)].

• Page 6, second paragraph, second sentence:

The RRC recommends the following revisions: "This casing is emplaced and cemented into the bore hole from the base of the lowermost USDW [~~(bottom of the lowermost USDW)~~] up to the ground surface, serving to both prevent fluids from entering USDWs and prevent migration of fluids between USDWs and other formations, as the casing isolates the injection fluid.

• Page 6, second paragraph, fourth sentence:

The RRC recommends the following revisions: "The long string casing is routinely [~~can be~~] perforated in the injection zone to allow fluid to flow out of the injection well and into the injection formation.

• Page 7, first paragraph, first sentence:

The RRC recommends the following revisions: "Cement is important for providing structural support of the casing, preventing contact of the casing with corrosive formation fluids, and preventing vertical movement of fluids and gases, including carbon dioxide.

• Page 7, fourth paragraph, first sentence:

The RRC recommends the following revisions: "A packer is a sealing device at the lower end of the tubing which keeps fluid from migrating from the injection zone into the annulus between the long string casing and tubing."

• Page 8, second complete sentence:

The RRC recommends the following revisions: "The casing and radius of curvature of the well should be designed so that any equipment/tool that may be used in the well will pass [~~fit~~] without getting stuck."

• Page 8, third paragraph, first sentence:

The sentence states that "The owner or operator of the well must submit to the UIC Program Director construction plans, including casing diameter, radius of curvature, and angle of deviation at the time of the permit application [§146.82(a)(12)]." The RRC was unable to find the terms "radius of curvature, and angle of deviation" in the GS rule. Also, subpart §146.82(a)(12) references §146.86, where numerous well construction requirements are listed.

Therefore, the RRC recommends the following revisions: "The owner or operator of the well must submit to the UIC Program Director construction plans in accordance with §146.90, regarding testing and monitoring requirements. The UIC Program Director may require that the construction plans include radius of curvature and angle of deviation.

• Page 8, third paragraph, second sentence:

The RRC recommends the following revisions: "They must also submit a Testing and Monitoring Plan [~~which would include the tests and specific pieces of equipment to be used during testing and logging of the well [§146.82(a)(15)]~~] in accordance with §146.90, regarding testing and monitoring requirements."

• Page 8, last paragraph, second sentence:

The RRC recommends the following revisions: "The UIC Program Director will be evaluating the information submitted on the proposed injection well requirements [~~casing diameter, deviation angle, and radius of curvature~~] and compare that information to [~~the diameters and lengths of the various pieces of~~] related procedures and equipment proposed for use in the Testing and Monitoring Plan for the sake of consistency."

• Page 14, last paragraph, second and third sentences:

The RRC recommends the following revisions: "A long string casing must extend through [~~to~~] the injection zone and be cemented to the surface [§146.86(b)(3)]. When cement cannot be recirculated to the surface, and the owner or operator can demonstrate by this using logs, it may be permitted [~~is permissible~~] to use staged cementing to achieve cementing to the surface [§146.86(b)(4)]."

• Page 15, first paragraph:

The RRC recommends the following revisions: "As previously discussed, the surface casing provides stability to the well bore and typically allows the amount of drilling mud used in the deeper portions of the well to be decreased. By extending it through the base of the lowermost USDW, the surface casing also seals off USDWs and other permeable zones from deeper intervals of the well bore. Thus, it [~~and~~] provides an additional barrier to deep fluid or injectate migration into a USDW if the tubing and long string casing should fail. Cementing of the long string casing serves to seal off the well bore and may prevent [~~prevents~~] fluid or injectate leaks through [~~from~~] the casing from entering a permeable zone, such as a USDW. If the cement was absent, and there was a tubing and casing failure, carbon dioxide could enter a permeable zone and then potentially migrate into USDWs through an empty annulus, faults, or abandoned wells, which would be a permit violation and potentially harm USDW's [~~failure of mechanical~~

~~integrity~~]. This would result in cessation of injection [§146.88(f)]. Cementing the casing also [~~prevents fluids from traveling up the annulus and protects the casing~~] <u>protects it</u> from exposure to carbonated brine and other corrosive fluids."

• Page 15, fifth paragraph, second and third sentences:

The RRC recommends the following revisions: "During well drilling, fluid or mud is circulated through the well bore to lubricate the drill bit and remove rock <u>cuttings</u> [~~debris~~] generated during drilling. The pressure created by <u>a column of</u> [~~the circulated~~] drilling mud also serves to prevent fluids from intruding into the well bore from the formation.

• Page 16, first complete sentence.

The RRC recommends that EPA delete this sentence: "Sophisticated equipment is commonly used to precisely control drilling fluid pressure and maintain the proper pressure throughout the entire process." Drilling fluid pressure is controlled by changing its density, and such changes are based on experience in the area and on hole conditions.

• Page 19, second complete paragraph:

The RRC recommends that EPA clarify or revise this paragraph. A cement column only " half as high" would appear to violate the rule requiring cement from the bottom of casing to the surface. Also "being sure the cement has reached the bottom of the casing" creates many problems with respect to the rule(s) and may create problems with the well. What is described is somewhat like a Bradenhead squeeze, which is not allowed in Texas. Finally, the location of cement can be found using cement bond logs, not gamma logs.

• Page 19, last paragraph, fifth sentence:

The RRC recommends the following revisions: "A cement evaluation log that radially investigates the cement for each casing <u>string</u> must be submitted to the UIC Program Director upon installation of the casing [§146.87(a)(2),(3)].

• Page 20, first complete paragraph, first sentence:

Whether or not a cementing method is capable of circulating to the surface can only be determined at the wellsite. Therefore, the RRC recommends the following revisions: "The UIC Program Director will review the proposed cementing method to determine if it is <u>likely to</u> [~~capable of~~] circulating to the surface.

• Page 22, second paragraph, last sentence:

The RRC recommends the following revision: "Non-Portland cements which are not <u>as</u> susceptible to attack by carbon dioxide are also available, including phosphate based, pozzolan-lime, gypsum, microfine, expanding cements, calcium aluminate, latex, resin or plastic cements, and sorel cements.

• Page 22, third paragraph, last sentence:

The RRC recommends the following revisions: "The [~~In the casing of the tubing, the burst strength~~] tubing must be designed with burst strength to withstand the injection pressure and with the collapse strength to withstand the pressure in the annulus between the tubing and the casing."

• Page 22, fifth paragraph, second sentence:

The RRC recommends the following revisions: "Proper materials for packers are important as they are likely to come into contact with carbon dioxide, or corrosive [~~saturated~~] brines at some point during the project life.

• Page 22, fifth paragraph, last sentence:

The RRC recommends the following revisions: "Therefore, to obtain the best measurement of the quality of the cement bond through the confining layer as possible, EPA recommends placing the packer within 100 feet above the perforations and within a cemented interval [~~near the top of the confining layer~~] to obtain the best results.

• Page 23, first paragraph, second sentence:

The RRC recommends the following revisions: "Ideally the packer will be placed within 100 feet above the perforations and within a cemented interval [~~with the confining layer~~].

• Page 23, first paragraph, fourth sentence:

Because logging of the confining zone should occur in an openhole environment before casing is run, or in cased hole without the tubing, the RRC requests clarification of the following sentence: "If the packer is placed in the injection zone, logging of the confining layer may be more difficult."

• Page 24, first paragraph, next to last sentence:

The RRC recommends the following revisions: "Surface valves are typically connected [~~hooked~~] to a SCADA or other similar system that monitors variables such as pressure, temperature, and flow."

• Page 25, second complete paragraph, first sentence:

The RRC recommends the following revisions: "The UIC Program Director will review the type of shut-off system proposed and evaluate its utility [~~appropriateness~~] for the proposed well."

• Page 27, first paragraph, first sentence:

The RRC recommends the following revisions: "Unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs, the [~~The~~] GS Rule requires that annular pressure between the tubing and the casing be maintained higher than the injection pressure. The rule also requires [~~and~~] that the annulus be filled with a non-corrosive fluid [§146.88(c)]."

• Page 28, second paragraph, first sentence:

The RRC recommends the following revisions: "At least two casing strings [~~casings~~] are used in the construction of a Class VI injection well."

Region 5 Comments on
Draft Underground Injection Control (UIC) Program Class VI Well Site Characterization Guidance for Owners and Operators – March 2011

General Comments
The biggest problem with this document is that its title does not match its contents: the title indicates it is guidance for owners and operators but the text contains much more background information (related to standard industry practices) than would be needed by the target audience. It seems to be aimed instead at the general public, though far too much industry jargon is used for the lay person. The document could probably be reduced by half by eliminating the rather detailed background discussions of what is routine practice in the well-drilling industry.

The second biggest problem is partially a result of the first problem: there is far too little guidance in this document. Instead it is a catalog of techniques with little distinction made between ones that are recommended and ones that are not. The guidance that is present is like needles in a haystack, buried in the mass of words.

There is little (if any) mention of Quality Assurance (QA) in this document. Given that it is aimed at the collection of data that will be used in environmental decision making, this is a serious omission and does not match EPA policy. QA is crucial and should be discussed in detail.

If possible, figures should be designed such that they will reproduce adequately in black-and-white, since it is highly likely that copies of the document will be printed or copied in black-and-white rather than color.

Draft Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance for Owners and Operators – March 2011

General Comments
Although there is generally too much background information, we must be cautious when we are looking at an area that may be new to many regulators. In this document, there is background information on modeling that may be useful.

There needs to be a clear indication on the different types of area of review wells and how they should be handled. For example, open holes are not the only area of concern. Wells with no external cement outside of the casing can also sure as conduits for upward fluid movement. Having defined values or "acceptable" cement plug sizes would be very helpful, but we understand that the evaluation of risk is not always that simple.

The sections on evaluating AoR wells can be greatly reduced. If there are abandoned wells in the AoR in question, I think that they would not have these various logging tools run on them but would be simply replugged.

It needs to be explicitly stated that changes in the AoR and/or Corrective Action Plan after the permit is issued (e.g., at the five year reevaluation cycles) will result in a major permit modification. This is something that can be stated to eliminate any ambiguity.

Should there be some discussion regarding the surface air monitoring plans what will be required under the Clean Air Act's greenhouse gas reporting rules? Revisions of an AoR might in turn require a revision of a surface air monitoring plan.

Other General Comments Regarding All Four Draft Guidances

The draft guidances have too much background material in most cases. The large volumes create multiple problems: hard to find things that are useful; hard to find things that are missing; and can be a barrier to users if they have to wade through a long document to find procedures to follow.

The formatting between some of the documents did not appear to be consistent. There were noted variations between them on: EPA logo size; the footer formatting, page numberings; bibliography formatting; and how the U.S. EPA is abbreviated. We realize that these differences are largely cosmetic, but thought that we would let you know.

The timeframe for review of these documents was limited. We appreciate the extension for the review of them, but even with that, staff was pressed to review them in time. The new nature of many of the activities covered under these draft guidances also limit the effectiveness of staff's review of them. Given this, we suggest that these guidances be revisited in six years when the GS rules will be reevaluated as part of the adaptive rule making approach.

MOWREY
MEEZAN
CODDINGTON
CLOUD
LLP

Kipp A. Coddington
Mowrey Meezan Coddington Cloud LLP
6830 Elm Street, Suite M6
McLean, Virginia 22101
[redacted]

COMMENTS OF THE NORTH AMERICAN CARBON CAPTURE & STORAGE ASSOCIATION ON THE ENVIRONMENTAL PROTECTION AGENCY'S DRAFT GUIDANCE REGARDING SITE CHARACTERIZATION FOR CLASS VI WELLS, AREA OF REVIEW & CORRECTIVE ACTION FOR CLASS VI WELLS, WELL CONSTRUCTION FOR CLASS VI WELLS, AND PLAN DEVELOPMENT FOR CLASS VI WELLS UNDER THE UNDERGROUND INJECTION CONTROL PROGRAM

May 31, 2011

On behalf of the North American Carbon Capture and Storage Association ("NACCSA"), we are pleased to provide the Environmental Protection Agency ("EPA") with these comments on the following four March 2011 draft guidance documents for Class VI wells under the Safe Drinking Water Act's ("SDWA") Underground Injection Control ("UIC") program: (1) Site Characterization (EPA 816-D-10-006); (2) Area of Review ("AoR") and Corrective Action (EPA 816-D-10-007); (3) Well Construction (EPA 816-D-10-008); and (4) Plan Development (EPA 816-D-10-012).

About NACCSA

NACCSA is a nonprofit organization of companies in North America that support the development of a sustainable carbon dioxide capture and storage ("CCS") industry in the United States and Canada. NACCSA members[1] include companies involved in developing commercial processes to mitigate greenhouse gas emissions through CCS, and specialists engaged in the technical, commercial, financial and developmental aspects of CCS activities in both the U.S. and Canada.

General Comments

NACCSA applauds EPA for establishing a regulatory regime for geologic sequestration including finalization of the Class VI rule and subparts RR/UU to the Clean Air Act's Mandatory Reporting Rule.

We also appreciate the time and effort that EPA is putting into preparing detailed and thoughtful guidance for the Class VI rule. That said, we have some concerns about the guidance documents collectively.

First, they fail to explain that geologic storage is anticipated to be safe and effective for well selected regulated sites, based upon numerous published studies and reports. The guidance presents a misleading and potentially prejudicial picture of the technology which will, at minimum, undermine public acceptance. The guidance fails in most moments to present an accurate and balanced portrayal the risks.

To properly put risks into context, EPA might wish to include the following statement at the beginning of each document[2]:

> On a project-by-project basis, the risks of geological storage of CO_2 are expected to be no greater than the risks associated with analogous industrial activities that are under way today. Oil and gas production operations, natural gas storage, and the

[1] NACCSA members are American Electric Power; American Petroleum Institute; Anadarko Petroleum Corporation; Arch Coal Inc.; Blue Source LLC; Denbury Resources, Inc.; Halliburton; Kinder Morgan; Occidental Petroleum Corporation; Peabody Energy; Sasol; Schlumberger Carbon Services; Shell; and Tenaska.

[2] The following statement is based upon text in, but does not constitute verbatim quotes from, Benson, S., "Carbon Dioxide Capture and Storage: Assessment of Risks from Storage of Carbon Dioxide in Deep Underground Geological Formations" (Lawrence Berkeley National Laboratory, April 2006) and Dooley, J., "Carbon Dioxide Capture and Geologic Storage: A Core Element of a Global Energy Technology Strategy to Address Climate Change" (Battelle, 2006).

disposal of liquid and hazardous waste have provided experience with underground injection of fluids and gases on massive scale. The injection volume of an individual storage project will be comparable to the larger scale CO_2-EOR projects taking place in the U.S. today. Because the technology for characterizing potential CO_2 storage sites, drilling injection wells, safely operating injection facilities, and monitoring will be adapted and fine-tuned from these mature industrial practices taking place today, it is reasonable to infer that the level of risk will be similar.

A recent assessment of CO_2 capture and storage authored by 32 authors from around the world concluded that, based on multiple lines of evidence regarding the short and long-term security of geological storage, for large-scale CO_2 storage projects (assuming the sites are well selected, designed, operated and appropriately monitored) it is likely the fraction of stored CO_2 retained is more than 99% over the first 1,000 years. The expected long retention times, combined with a wealth of related experience with large-scale injection, led these authors to conclude (IPCC, 2006):

> With appropriate site selection informed by available subsurface information, a monitoring program to detect problems, a regulatory system, and the appropriate use of remediation methods to stop or control CO_2 releases if they arise, the local health, safety and environment risks of geological storage would be comparable to risks of current activities such as natural gas storage, EOR, and deep underground disposal of acid gases.

All of these current activities – natural gas storage, EOR, and deep underground disposal of acid gases – enjoy long histories of safe and environmentally sound regulation under regulatory regimes that are less stringent than the final Class VI rule. With the exception of EOR, these analogues also deal with substances that have different risk profiles than carbon dioxide.

Sudden releases of CO_2 are unlikely. To the extent that leakage does occur, the most likely pathways are transmissive faults and unsecured abandoned wells. In order to migrate back to the surface, a molecule of CO_2 would have to find its way through many layers of low-permeability rock, through which it might move only centimeters per century. Finding its way to the surface by moving upwards through thousands of meters of solid rock could take millennia.

CO_2 leakage from deep geologic formations is therefore not principally about human health and welfare today. The concern relates to slow, undetected leakage and how that might impact the climate for future generations.

The likelihood and extent of any potential CO_2 leakage should slowly decrease as a function of time after injection stops. This is because the formation pressure will

> begin to drop to pre-injection levels, as more of the injected CO_2 dissolves into the pore fluids and begins the long-term process of forming chemically stable carbonate precipitates.
>
> Such assessments, taken together with actual operating experience from three CO_2 storage projects with a collective operating experience spanning 20 years, suggest that CO_2 storage in deep geological formations can be carried out safely and reliably.

We similarly encourage EPA to ensure that the "Reference" section at the end of each guidance document reflects a balanced treatment of the CCS literature. Appendix A to these comments provides some of the literature which we believe should be cited and referenced in the guidance documents, as necessary and appropriate.

We separately are concerned that the guidance documents suggest that the Class VI program is moving away from the SDWA's focus on protecting underground sources of drinking water ("USDW") and towards a mentality that "any data are good, and even more are better, " regardless of the relevance of such data for USDW protection in the AoR. The primary purpose of the Class VI rule is the protection of USDWs within the AoR. Class VI, moreover, is for commercial, not research, projects.[3] NACCSA fully supports CCS R&D; we do not, on the other hand, support the use of Class VI as a mechanism to require commercial entities to obtain generic geologic data for purposes other than meeting the USDW-protection focus of Class VI.

We also fret that the guidance documents go too far in including advisory recommendations that go well beyond what the final Class VI rule requires; indeed, as we highlight below, in at least one instance the guidance seems to disparage the rule. We very much appreciate that EPA is trying to be helpful in providing guidance but we see two problems with EPA's approach. First, because the regulatory regime is new, advisory statements are apt to become binding, despite the fact that the Class

[3] 40 C.F.R. § 144.6(f).

VI rule is premised on the appropriate notion of meeting performance standards in light of local geologic conditions. The second issue is the sheer scope of the guidance, with even more to come. The regulatory regime is new and untested, and now EPA is in the midst of promulgating voluminous guidance. On these facts, guidance could have the perverse and unintended consequence of creating more, not less, uncertainty about the permitting process.

On a related front, the issuance of guidance in piecemeal fashion makes it difficult for the regulated community to provide comments and to understand the regulatory regime. Prior to issuance of these four documents, EPA finalized guidance on financial responsibility. EPA states that the following guidance will be released in the months ahead: (i) testing & monitoring guidance; (ii) well plugging, post injection site care guidance; (iii) the "interim final class VI primary application and implementation manual"; (iv) recordkeeping, reporting, an data management guidance; (v) injection depth waivers guidance; (vi) transitioning from Class II to Class VI guidance; and (vii) options for Class V experimental technology wells guidance (EPA 816-D-10-012, pp. 6-7). So that makes a total of twelve (12) guidance documents or manuals already issued or in process. And all of these documents are interrelated to some extent. We cannot comment on guidance that has not yet been issued, of course, nor can we thoughtfully assess the entire regulatory regime until all of the guidance has been issued. These comments are thus necessarily preliminary and subject to later modification as additional guidance is issued.

Guidance-Specific Comments

a. Guidance on Site Characterization (EPA 816-D-10-006)

Site characterization is an initial critical step in the permitting process. Data regarding site characterization is also used to delineate the AoR.[4] Indeed, delineating the AoR is one of the primary purposes of the site characterization data. The computational model that delineates the AoR incorporates site characterization data.[5] Site characterization data are also used during corrective action.[6] The AoR alone constitutes a large chunk of the "geologic sequestration program" that is the focus of the Class VI permit.[7] Site characterization data underpin the Class VI program, which in turn, as noted, is focused on identifying the AoR and protecting USDWs within the AoR.[8]

The Class VI rule's focus on the AoR is confirmed by the information that owners/operators of Class VI wells must submit with their permit applications.[9]

The Class VI rule also sets forth what amounts to a prudent, AoR-focused performance-based standard for siting which itself is underpinned by site characterization data[10]:

> "(a) Owners or operators of Class VI wells must demonstrate to the satisfaction of the Director that the wells will be sited in areas with a suitable

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[4] 40 C.F.R. § 146.84(a) ("The area of review is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity .. [and] is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data") (emphasis added).

[5] 40 C.F.R. § 146.84(b)(1).

[6] 40 C.F.R. §§ 146.84(c)(1), (2) and (3).

[7] 40 C.F.R. § 146.81(d) (definition of "geologic sequestration project").

[8] 40 C.F.R. § 146.81(d) (definition of AoR: "the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity").

[9] 40 C.F.R. § 146.82 (required class VI permit information); *see, e.g.*, §§ 146.82(a)(2) ("[a] map showing the injection well for which a permit is sought and the applicable [AoR]"), 146.82(a)(3) ("[i]nformation on the geologic structure … of the proposed storage site"), 146.82(a)(4) ("[a] tabulation of all wells within the [AoR]"), 146.82(a)(5) ("[m]aps … indicating the general vertical and lateral limits of the all USDWs … within the [AoR]").

[10] 40 C.F.R. § 146.83 (minimum criteria for siting). "Injection zone" is defined as a "geologic formation, group of formations, or part of a formation that is of sufficient areal extent, thickness, porosity, and permeability to receive carbon dioxide through a well or wells associated with a geologic sequestration project" (*id.* § 146.81(d)).

geologic system. The owners or operators must demonstrate that the geologic system comprises:

> "(1) An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream; [and]
>
> "(2) Confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s)."

This performance-based standard respects the fact that permitting decisions are inherently local because all geology is local, based on site specific data, and not well-suited for the application of general approaches.

Unfortunately, the Class VI rule's focus on defining an AoR for purposes of protecting relevant USWDs is undermined by the guidance's suggestion that site characterization should occur on "two scales"—the AoR itself, and then "regional" data surrounding the AoR (EPA 816-D-10-006, p. 5). The guidance hints at what EPA believes "regional-scale" data to be: "large-scale settings (e.g., <u>mid-continent basins</u>)" (EPA 816-D-10-006, p. 6) (emphasis added). The guidance then "recommends" that applicants provide a wealth of data on USDWs, including those outside of the AoR (<u>id</u>., p. 10) (applicant should provide data on "all USDWs in the AoR and <u>the region</u>, and whether they are currently being used for drinking water") (emphasis added).

We recognize that, in the context of a specific permit, regional site characterization data may be critically important for protecting USDWs within the AoR. But including a blanket recommendation that regional, non-AoR data always be assessed, however, is inconsistent with the final Class VI rule. The guidance suggests that a requirement to provide out-of-AoR regional site characterization data is based on § 146.82(a)(3)(vi) (EPA 816-D-10-006, p. 5). While it is true that § 146.82(a)(3)(vi) refers to "[g]eologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area," that provision is limited by the parent section, § 146.82(a)(3), which makes clear that all data are to be focused on the "proposed storage site and overlying formations." Nothing in the final Class VI rule may fairly be read to require the owner/operator to provide "regional" data unrelated to USDW protection within the AoR. Requiring the collection and submission of generic regional data will only frustrate permitting and lead to the imposition of unnecessary costs.

Section 3 of the guidance is appropriately focused on the site characterization data that could be useful for delineating the AoR. Here again, however, the guidance drifts from the performance-based siting criteria of the final Class VI rule and instead presents suggested data sets, approaches, and analytic techniques that are apt to become binding in all permit proceedings, even when the local geology dictates a different result. The guidance belatedly notes that the final Class VI rule "does not specify which methods should be used for Class VI injection wells; the choices of analyses and the data needed will depend on site geology" (EPA 816-D-10-006, p. 114). NACCSA agrees and suggests that the Class VI program would be better served if the guidance merely repeated that fact.

b. Guidance on AoR and Corrective Action (EPA 816-D-10-007)

The final Class VI rule provides a comprehensive, performance-based definition of the AoR[11]:

> "(a) The area of review is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data."

[11] 40 C.F.R. § 146.84(a).

The guidance elaborates that USDWs "may be endangered" by: (1) the direct movement of carbon dioxide into a USDW that impairs drinking water through various mechanisms; and (2) the movement of non-potable water (e.g., brine) out of the injection formation and into a USDW as a result of elevated pressures (EPA 816-D-10-007, p. 2). The former is premised on assumptions regarding existing conduits in the injection formation to USDWs. The latter is based on assumptions regarding a "closed system" pressure model of the injection and surrounding formations.

Both of these assumptions may be valid or invalid in any specific case. They are both unlikely to be valid in all cases, which makes their inclusion in the guidance without appropriate caveats potentially problematic. With respect to the first assumption (existing conduits), if conduits existed between saline formations and USDWs, one would expect to routinely find reports of naturally occurring saline intrusions because of existing pressure gradients. The guidance does not appear to cite data that supports the existence of such conditions, and the existence of hundreds of feet of confining and trapping layers between target and non-target formations would appear to make assumptions regarding existing conduits invalid as a general rule. With respect to the second assumption (the "closed system" model), at least one new paper appears to challenge it, yet the guidance does not make note of that paper.[12]

Section 2 of the guidance includes background information on computational modeling. NACCSA questions whether such information is helpfully included in a guidance document that is intended to facilitate permitting. Computational modeling will be vetted case-by-case in individual

[12] Q. Zhou, "On Scale and Magnitude of Pressure Build-Up Induced by Large-Scale Geologic Storage of CO_2," Greenhouse Gas Sci. Technol., 1-11-20 (2011).

permitting proceedings, with ample input from experts, as EPA itself acknowledges.[13] We do not believe that the guidance should explain in detail what computation modeling is.

NACCSA appreciates EPA's inclusion of a recommendation regarding performing AoR delineation and corrective action "comprehensively for all wells included within a single project" despite the fact that the final Class VI unfortunately does not allow area permits (EPA 816-D-10-007, p. 2). The absence of area permits for sequestration projects is unfortunate, as it is important that a project be analyzed and permitted comprehensively. A comprehensive approach would not only better achieve the regulatory program's goal of protecting USDWs in the AoR, it would ensure a more efficient use of resources by the regulated community and regulators during the permitting process. An example of why a comprehensive approach to permitting is important deals with the relationship between injection and monitoring wells. In some scenarios, two (or more) injection wells at a project could be operated collaboratively to allow one of the injection wells to serve a monitoring function, thereby negating the need for a separate monitoring well. This would be a win-win outcome, as one less penetration would be drilled into the target formation, and the owner/operator would incur lower costs. The regulatory regime should encourage the adoption of smart solutions such as this, if local conditions warrant, of course. Smart solutions are apt to emerge from comprehensive, not piecemeal or well-by-well, project planning. In all moments, the guidance should emphasize the important role that comprehensive, coordinated project-wide permitting and planning is going to play for geologic sequestration projects.[14]

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[13] EPA 816-D-10-007, p. 24 ("EPA recommends that model development in all cases be conducted by a professional expert with the understanding of multiphase flow processes and experience with application of sophisticated computational models").

[14] EPA 816-D-10-007, p. 26 ("In the case of GS projects with multiple Class VI injection wells, it is important to note that each Class VI well is required to be permitted separately, as area permits are not allowed ... However, EPA strongly encourages potential Class VI injection well owners and operators to account for all injection wells associated with the

Section 3 of the guidance deals with "AoR Delineation Using Computational Models." This section includes advisory statements that could complicate permitting[15]:

> "EPA recommends that the lateral and vertical extents of all formations predicted to exhibit contact with supercritical carbon dioxide or elevated pressure over the lifetime of the proposed GS project be well characterized. This may be an iterative process because initial model estimates of plume and pressure front migration may indicate further migration than previously assumed."

The first sentence above is helpful and informative; the second sentence is subjective, hypothetical and unhelpful.

EPA also may wish to reconsider the inclusion of a "hypothetical example" (EPA 816-D-10-007, pp. 28 et seq.). Hypotheticals run the risk of complicating, not facilitating, the permitting process because the permit writer and the public could be lead to believe that assumptions made in hypotheticals are valid in all instances.[16] We recommend that the example on pages 28-29 be struck.

The guidance unfortunately includes advisory statements regarding computational model design that exceed what is required by the final Class VI rule. The final Class VI rule provides that the computational model must be able to predict projected fluid and pressure gradient movements until "the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as

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proposed project … in the AoR model development. <u>If allowed by the UIC Program Director, a single AoR delineation model can be used for all Class VI injection well wells [sic] for a single GS project</u>") (emphasis added).

[15] EPA 816-D-10-007, p. 25.

[16] The example offered by EPA shows "[z]ones of known fracture concentration" and a "Schematic of Example Fracture System." It also suggests by visual effect that sequestration occurs at shallow depths, a situation that is not remedied by the caveat "Figure not to scale" (EPA 816-D-10-007, p. 28). A more accurate, informative and educational graphic would include "flip out" or "fold down" pages that graphically and dramatically demonstrated the deep depths at which sequestration occurred. EPA's example also erroneously suggests that carbon dioxide must be "99% pure at all times."

determined by the Director."[17] The guidance converts this rigorous, performance-based requirement into a "recommend[ation] that in all cases, the model is run long enough after injection cease that the migration of the carbon dioxide plume and pressure front have ceased to migrate, and steady-state conditions are reached in the subsurface" (EPA 816-D-10-007, p. 30) (emphasis added). The guidance then suggests that "it may be necessary for the model to simulate conditions at the GS project site for several hundred or thousands of years" (id.).[18]

This recommendation differs from what the rule requires in significant respects. With respect to pressure, the rule focuses on predicting when pressure differentials sufficient to cause fluid movement into a USDW are no longer present. The guidance, in contrast, states that the model must be run until the "pressure front ha[s] ceased to migrate" without regard to whether a USDW is imperiled. Similarly, the term "steady state" is subject to multiple interpretations – and could be largely meaningless when assessed over geologic time. The term also appears to exceed the regulatory standard.

In other key respects, the guidance differs with what the final Class VI rule requires. One of the most important, initial functions of the computational model is the delineation of the AoR, as discussed above. The regulatory language makes clear that the AoR, in turn, is focused on the protection of

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[17] 40 C.F.R. § 146.84(c)(1).

[18] In support of its recommendation for multi-thousand year modeling, EPA references Flett M, R. Gurton, & G. Weir, 2007, "Heterogeneous saline formations for carbon dioxide disposal: Impact of varying heterogeneity on containment and trapping," J. Petroleum Science and Engineering, 57:106-118. Without passing judgment on this paper, we caution against citing one paper for a general recommendation – an approach that all of the guidance documents do repeatedly. This approach runs counter to the final rule's prudent reliance on performance-based criteria, which respects the fact that all geology is local. We note that the subject covered by the Flett paper has been addressed by other researchers. Tsang, C. F., "A Comparative Review of Hydrologic Issues Involved in Geologic Storage of CO_2 and Injection Disposal of Wastes," Lawrence Berkeley National Laboratory (April 7, 2009). We do not know if Flett and Tsang are in agreement, nor does it really matter for our purposes here. What does matter is that the guidance most allow flexibility in the permitting process and avoid the imposition of "rules of thumb" – even if advisory – with selected reference to literature.

potentially impacted USDWs using a rigorous, performance-based metric.[19] The guidance converts this metric into an ambiguous advisory statement (EPA 816-D-10-007, pp. 31-32) (emphasis added):

> "EPA recommends that the boundaries of the AoR are based on predictions of the extent of the separate-phase (i.e., supercritical, liquid or gaseous) plume and pressure front, using <u>maximum-risk scenario simulations</u> with <u>reasonable input parameter values</u>. As such, EPA recommends that the AoR encompass the <u>maximum extent</u> of the separate-phase plume or pressure front (MESPOP) <u>over the lifetime of the project and entire timeframe of the model simulations</u>. The pressure front, as described below, is the extent of pressure increase of sufficient magnitude to force liquids from the injection zone into the formation matrix of a USDW through a <u>hypothetical open conduit</u>."

It is unclear what EPA means by terms such as "maximum-risk scenario simulations" and "reasonable input parameter values." And if owners/operators must assume the existence of "hypothetical open conduit[s]," one might question why site characterization data need be collected at all. Whatever else may be said, the guidance seems to be focused on making the AoR as large as possible, without regard to actual site risks.[20]

NACCSA supports the guidance's reaffirmation that owners and operators may use phased corrective action (EPA 816-D-10-007, p. 56).

With respect to AoR reevaluation, NACCSA encourages EPA to add language to the guidance that indicates that owners/operators may meet a performance-based standard instead of a rigid, minimum fixed period of five years. The final Class VI rule provides that owners/operators must reevaluate the

[19] 40 C.F.R. §§ 146.84(a), (c)(1).

[20] These may be an under appreciation of what the size of the AoR means for a project. The size of the AoR influences related topics such as pore space to be acquired (if necessary) and corrective action. Setting hypothetical parameters for the model that are devoid of actual site characterization data, with the result that the AoR is expanded beyond any reasonable assessment of risks to relevant USDWs, will hinder commercial projects. Selection of the AoR's size must be rigorous and thorough, with adequate margins for safety as necessary and appropriate on a case-by-case basis in light of site characterization data and computational modeling with the goal of protecting USDWs; this outcome is ensured by application of the rule's performance standard metric. Going further than this metric, as EPA does in the guidance, runs the risk of converting the commercial Class VI program into a research endeavor.

AoR "when monitoring and operational conditions warrant."[21] While the rule also includes the five-year minimum requirement, we do not read it to rigidly require an AoR reevaluation every five years. A better approach would be requiring the initial AoR reevaluation to occur five years following commencement of initial injections, at which time site data would be checked against the computational model. If the data were in agreement with the computational model, the period of time when the AoR was next reevaluated would be extended – say, for ten (10) years.[22] Corrective action would be phased in accordingly as well. This performance-based standard would not jeopardize site performance or safety, or detract from the iterative corrective action process. It instead would make the AoR reevaluation process more manageable, particularly in light of the fact that the guidance separately drives the process towards the creation of an exceedingly large initial AoR, as discussed above.

NACCSA is concerned that the guidance's recommendations regarding AoR evaluation upon "significant changes in site operations" are too broad and ambiguous, and will lead to compelled AoR re-evaluations for industry practices that are business as usual.[23] The guidance suggests that such changes could include a "change in the composition of the injectate or changes in fluid production rates from the injection or overlying zones" (EPA 816-D-10-007, p. 59). The guidance then includes the following catch-all recommendation: "In addition, the owner or operator may choose to perform an AoR evaluation based on other operational changes, with the approval of the UIC Program Director" (id.).

[21] 40 C.F.R. §§ 146.84(e).
[22] Obviously, in the unlikely event of a significant disagreement between site data and the computational model, more immediate and intermediate steps would be taken.
[23] In contrast, we agree with EPA that AoR reevaluation is warranted when there is a significant disagreement between monitoring data and the computational model, or when new site characterization data are obtained that may significantly change model predictions and the delineated AoR. Qualifiers such as "significant" and "significantly" – which the guidance currently uses in this context (EPA 816-D-10-007, p. 59) – are appropriate and necessary. They also should be tied to endangerments to USDWs.

As written, <u>any</u> "operational change" at the geologic sequestration site, the pipeline supplying the site, or the industrial source(s) supplying the CO_2 could compel an AoR reevaluation. This is much too broad, as industrial operations undergo "operational changes" with some routine frequency – down time for planned or emergency maintenance, for example, or standard fluctuations in commodity specifications or pressures within specified limits.[24] The guidance should make clear that the <u>only</u> operational changes that may trigger an AoR reevaluation are those that: (i) site data or the computation model indicate pose an endangerment to USWDs in the AoR; (ii) are permanent (thereby excluding time-limited events such as planned shutdowns for maintenance and the like); and (iii) occur at the geologic sequestration site, not upstream of it.

c. Guidance on Well Construction (EPA 816-D-10-008)

Much of this guidance repeats what is already provided in the final Class VI rule. EPA itself acknowledges that "[i]njection well construction is a well known field and there are many resources available that describe the necessary construction details" (EPA 816-D-10-008, p. 2). We agree and suggest that this fact calls into question the need for the guidance.

This guidance presents a misleading picture of well risks, suggesting they are greater than they are (EPA 816-D-10-008, pp. 9-10) ("Although not anticipated during normal operations, another source of potential stress could be due to a rapid change in carbon dioxide volume in the event the carbon dioxide being injected undergoes a phase change. For example, this might happen if there was a sudden loss of pressure at the wellhead"). Another unfortunate reference is the term "Opening bomb" which appears in Figure 6 on p. 18 of the guidance. If statements and references such as these are retained, we

[24] A typical CO_2 offtake contract includes provisions for such operational changes.

recommend that they be appropriately explained and put into context, with ample citation to the literature documenting the low risks accompanying site operations.[25]

The guidance includes advisory statements that may complicate the permitting process, such as: "Owners or operators may also want to consider installation of landing nipples above the packer" (EPA 816-D-10-008, p. 8) (emphasis added). This recommendation may not be valid in all cases and runs counter to the notion of careful consideration of site-specific conditions during the permitting process.

The guidance repeats the provision of the final Class VI rule that the annular pressure between the tubing and the casing be maintained higher than the injection pressure (EPA 816-D-10-008, p. 27). The rule includes the following additional caveat: "… unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs" (40 C.F.R. § 146.88(c)). The guidance writes this caveat out of the rule. Flexibility regarding annular pressure requirements is important, as higher annular pressure may cause stresses that increase relevant risks in a specific case.[26]

d. Guidance on Project Plan Development (EPA 816-D-10-012)

EPA should withdraw this guidance as a careful read of it suggests that it is predicated upon assumptions about how the permitting process may work. Our specific comments follow.

The iterative nature of plan development will frustrate permitting and hinder project finance. The guidance envisions a repeating process of plan revisions, some of which may have to be done well-by-well instead of for the geologic sequestration project (EPA 816-D-10-012, pp. 2-3) (emphasis added):

[25] *See, e.g.*, J. Heinrich, "Environmental Assessment of Geologic Storage of CO_2" (Massachusetts Institute of Technology (2003) ("environmental issues arising from CO_2 flooding seem to be inconsequential").

[26] Hypothetically, under the final Class VI rule, it is conceivable that the bottom hole annular pressure could exceed the relevant fracking pressure.

"EPA recommends that owners or operators consider revising or adjusting portions of the project plans as additional data become available during the site characterization process .... All five of the project plans must be submitted with the Class VI permit application (i.e., prior to operation of the injection well or drilling of any test wells). Therefore, the owner or operator will need to develop plans prior to formal modeling of the AoR. While certain preliminary information would be available at that time, e.g., the estimated extent of the AoR based on initial geologic data and planned injection volumes, EPA recommends that the owner or operator revisit and revise the operational-phase plans (e.g., the AoR and Corrective Action Plan, Testing and Monitoring Plan, and Emergency and Remedial Response Plan) as necessary once the AoR modeling has been completed. This would for example, help ensure that the AoR and Corrective Action Plan addressed all improperly abandoned artificial penetrations throughout the delineated AoR, that planned testing and monitoring is thorough, or that the Emergency and Remedial Response Plan addresses all potential resources and infrastructure that may be impacted by the project."

It is difficult to discern from the above precisely how the planning process is to work, but one interpretation follows: (1) five plans (perhaps per-well, too, so if the geologic sequestration project involved three wells, fifteen plans could in theory be required) are submitted before the owner/operator has drilled a test well; (2) each of the five plans thereafter is revisited and revised during the site characterization process; and (3) finally, once the computational model is finished, each of the five plans is further revised "as necessary."[27] Some of the plans also must address "all potential resources and infrastructure."[28]

If our interpretation is correct, the project planning process is a recipe for regulatory gridlock. Putting aside issues of the time and resources required by the owner/operator and regulator to prepare and review each plan, the plan revision process appears to have no end as any plan may be required to

[27] EPA makes clear that a change in one plan may necessitate a change to the others: "The five GS project plans are inter-related. Changes to (or information acquired through the implementation of) one plan may necessitate a review of, or possibly a change to, some or all of the other plans" (EPA 816-D-10-012, p. 4).

[28] The Class VI program is intended to protect USDWs, not "potential resources," whatever they may be.

be further revised "as necessary." "As necessary" is not a regulatory standard; it's a criterion for arbitrary decision-making. This process will retard, not advance, commercial projects.

We offer two better approaches. First, pull back the guidance and wait until regulators and the regulated community have experience with the final Class VI rule. Or, in the alternative: (i) plans should be required for geologic sequestration projects, not per well; (ii) plans should be prepared once initially – after site characterization and the computational model are complete; and (iii) thereafter, an individual plan is only required to be "updated" if there is an event that otherwise triggers a reevaluation of the AoR (as modified by our comments above pertaining to reevaluation of the AoR).

<u>The guidance suggests that compliance with the Class VI rule is "not enough"</u>. We were taken aback by the following statement in the guidance (EPA 816-D-10-012, p. 3) (emphasis added):

> "In their discussion of the plans, EPA recommends that the owner or operator and UIC Program Director <u>consider the advantages</u> of tailoring activities to project conditions, and <u>not necessarily performing only the minimum activities required by the GS Rule</u>. For example, <u>increasing the number of monitoring locations or the frequency of AoR reevaluations</u> may help ensure that future reviews of the project plans <u>will not necessitate amendments or permit modifications</u>. This type of <u>proactive planning</u> early in the process may help ensure that the owner or operator and the UIC Program Director have considered both the current and possible future conditions at the proposed Class VI injection well site based on all available site-specific information."

This statement is problematic on several levels. For starters, it advances a pejorative view of the motives of owners/operators that is inaccurate and prejudicial. It suggests that compliance with the final Class VI rule is "not enough" – and if that's the case, EPA should amend the rule. It erroneously suggests that the rule sets minimum standards, when in fact it appropriately imposes rigorous performance-based criteria.

Further, the statement oddly suggests without basis or analysis that the number of monitoring wells be increased – and in so doing fails to consider issues such as: (i) each penetration of the injection zone potentially increases site risks; (ii) each monitoring well will have to be separately permitted (with perhaps five additional plans for each), thereby discounting issues such as permitting burden and imposition of unnecessary costs; and (iii) drilling unnecessary wells will frustrate project finance and unnecessarily increase project costs.[29]

The guidance makes reference to documents that have not yet been published, frustrating one's ability to provide thoughtful comments. EPA refers the reader to the following "forthcoming" guidance documents and manual for more information: (i) testing & monitoring guidance; (ii) well plugging, post injection site care guidance; (iii) the "interim final class VI primary application and implementation manual"; and (iv) recordkeeping, reporting, an data management guidance (EPA 816-D-10-012, pp. 6-7). EPA also notes that the following additional documents will be forthcoming: (i) injection depth waivers; (ii) transitioning from Class II to Class VI; and (iii) options for Class V experimental technology wells (id.). We cannot opine on documents that do not exist.

The guidance has the following to say about testing & monitoring (EPA 816-D-10-012, p. 22) (emphasis added and in original):

> "Guidance presenting recommended approaches to performing the activities under the approved Testing and Monitoring Plan (e.g., how to select appropriate testing equipment, monitoring techniques, locations and frequencies) can be found in the forthcoming *Draft UIC Program Class VI Well Testing and Monitoring Guidance* posted on EPA's website, when available for the public .... Exhibit 3[30] presents highlights of the information presented in the guidance."

The referenced testing & monitoring guidance does not exist, so we could not ascertain if the discussion of testing & monitoring in this guidance conforms to what EPA will say about the same topic in that future guidance. We also cannot comment on Appendix C for the same reason. We reserve the right to

[29] Inclusion of this recommendation further suggests that EPA wants Class VI to be a research, not commercial, program.
[30] There is no Exhibit 3. We assume EPA meant Appendix C, which provides a "Sample Template of an Injection Well Plugging Plan."

comment on the testing & monitoring provisions of this guidance when EPA has completed issuing all guidance on this topic.[31]

The guidance largely repeats what it is the other guidance documents, creating grounds for potential confusion. For example, the guidance covers AoR and corrective action – a topic that is covered in a separate guidance document (EPA 816-D-10-012, pp. 8 et seq.). We were unable to confirm that the discussion of AoR/corrective action is identical in both documents.

* * *

NACCSA appreciates the opportunity to provide these comments.

Best regards,

Kipp Coddington

[31] The same situation applies with respect to the guidance's discussion of the injection well plugging plan and post-injection site care/site closure, two topics which we understand will be covered separately in forthcoming guidance EPA 816-D-10-012, pp. 36, 40). As above, we reserve the right to revisit these topics when the relevant guidance documents are issued.

Appendix A

Additional CCS Literature to be Cited

Benson, S., "Carbon Dioxide Capture and Storage: Assessment of Risks from Storage of Carbon Dioxide in Deep Underground Geological Formations" (Lawrence Berkeley National Laboratory, 2006)

Benson, S., "Carbon Dioxide Capture and Storage in Underground Geologic Formations" (Lawrence Berkeley National Laboratory) (from workshop proceedings, "The 10-50 Solution: Technologies and Policies for a Low-Carbon Future," Pew Center on Global Climate Change and the National Commission on Energy Policy)

Dooley, J., "Carbon Dioxide Capture and Geologic Storage: A Core Element of a Global Energy Technology Strategy to Address Climate Change" (Battelle, 2006)

Heinrich, J., "Environmental Assessment of Geologic Storage of CO_2" (Massachusetts Institute of Technology, 2003)

IPCC Special Report on CCS (2006)

"Natural and Industrial Analogues for Geological Storage of Carbon Dioxide" (IEA 2009)

Report of the Interagency Task Force on CCS (August 2010)

"Site Screening, Site Selection, and Initial Characterization for Storage of CO_2 in Deep Geologic Formations" (NETL 2010)

"The Future of Coal: An MIT Interdisciplinary Study" (MIT, 2007)

Zhou, Q., "On Scale and Magnitude of Pressure Build-Up Induced by Large-Scale Geologic Storage of CO_2," Greenhouse Gas Sci. Technol., 1-11-20 (2011)

energy API

Kyle B. Isakower
Vice President, Regulatory and Economic Policy

1220 L Street, NW
Washington, DC 20005-4070
USA
[redacted]

May 31, 2011

Cynthia C. Dougherty
Director
Office of Ground Water and Drinking Water
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N. W.
Washington, DC 20460

Submitted via email (Dougherty.Cynthia@epa.gov)

Re: Draft Underground Injection Control (UIC) Program Class VI Guidance issued March 29, 2011

Dear Director Dougherty:

The American Petroleum Institute (API) represents more than 470 oil and natural gas companies, leaders of a technology-driven industry that supplies most of America's energy, supports more than 9.2 million U.S. jobs and 7.5 percent of the U.S. economy, and, since 2000, has invested nearly $2 trillion in U.S. capital projects to advance all forms of energy, including alternatives. API has a strong interest in the development of the Underground Injection Control (UIC) program for Geologic Sequestration wells and provided extensive, detailed comments on the topics covered in the four draft guidance documents as part of its comments on the proposed Class VI rulemaking.

API complements EPA for clearly specifying within the guidance when it is making recommendations and offering alternatives that go beyond the minimum requirements indicated by the rule by prefacing these recommendations with the words "EPA recommends", "may" or "should." API urges EPA and state decision makers to carefully evaluate such recommendations though and not mandate them without due consideration. In many cases, the recommendations have the potential to significantly alter project economics and project viability for a marginal increase in groundwater protection and/or security of CO_2 confinement. API offers specific comments on the individual guidance documents below.

Sincerely,

Kyle Isakower
Vice President, Regulatory and Economic Policy

cc: Ann Codrington (codrington.ann@epa.gov)
Bruce Kobelski (kobelski.bruce@epa.gov)

API Comments on EPA's Draft Underground Injection Control Program Class VI Well Guidance for Owners and Operators

Disclaimer Language Comments

API appreciates EPA's disclaimer language aimed at clarifying that the UIC guidance documents are advisory and are not rules. We agree with EPA about the importance of this distinction. As EPA members consult materials such as this for compliance purposes, it is important that they can clearly, and with certainty, determine which requirements are legally-binding and which are merely informational, advisory, recommended or explanatory. To that end, API herein provides some additional recommended disclaimer language. We believe these edits help clarify the critical distinction between legally-binding mandates and guidance to be used as an aid to compliance.

Disclaimer

~~The Class VI injection well classification was established by the *Federal Requirements under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells* (The GS Rule) (75 FR 77230, December 10, 2010). No previous EPA guidance exists for this class of injection wells.~~

The Safe Drinking Water Act (SDWA) provisions and EPA regulations cited in this document, the Class VI injection well classification was established by the *Federal Requirements under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells* (The GS Rule) (75 FR 77230, December 10, 2010), contain legally-binding requirements. ~~In several chapters~~ This guidance document makes recommendations and offers alternatives that go beyond the minimum requirements contained in the SDWA and ~~indicated by~~ the GS Rule. This is done to provide information and recommendations that may be helpful for UIC Class VI program implementation efforts. Such recommendations and alternatives are prefaced by the words "may" or "should" and are to be considered advisory, not mandatory, because they are not required elements of the GS Rule. Therefore, this document does not substitute for those provisions or regulations, nor is it a regulation itself, so it does not impose legally-binding requirements on EPA, states, or the regulated community. The recommendations herein may not be applicable to each and every situation.

EPA and state decision makers retain the discretion to adopt approaches on a case-by-case basis that differ from this guidance where appropriate. Any decisions regarding a particular facility will be made based on the applicable statutes and regulations. Mention of trade names or commercial products does not constitute endorsement or recommendation for use. EPA is taking an adaptive rulemaking approach to regulating Class VI injection wells, and the Agency will continue to evaluate ongoing research and demonstration projects and gather other relevant information as needed to refine the ~~rule~~ guidance. Consequently, this guidance may change in the future without public notice. Any revisions to legally binding rules will be made pursuant to the federal Administrative Procedures Act.

While EPA has made every effort to ensure the accuracy of the discussion in this document, the obligations of the regulated community are determined by statutes, regulations or other legally binding requirements. In the event of a conflict between the discussion in this document and any statute or regulation, this document would not be controlling.

Note that this document only addresses issues covered by EPA's authorities under the SDWA. Other EPA authorities, such as Clean Air Act (CAA) requirements to report carbon dioxide injection activities under the Greenhouse Gas Mandatory Reporting Rule (GHG MRR) are not within the scope of this document.

Class VI Well Construction Guidance Comments

Comments on Regulatory Requirements for Well Construction within the Guidance
Given the flexible, adaptive approach EPA has adopted toward this rulemaking, (75 FR 77241), API offers the following comments with the intent of encouraging EPA to modify the more problematic requirements of the Class VI rule through its Guidance documents where possible or through rulemaking as appropriate.

1. The regulatory requirement for an operator to maintain a pressure in the annulus greater than the operating injection pressure (page 28) is unnecessary and could be harmful to the integrity of the wellbore and the confining or injection formation. EPA acknowledges that, in some circumstances, maintaining an annulus pressure greater than the injection pressure could result in a greater chance for damage to the well or the formation. As a result, the final rule provides the Director discretion to adjust this requirement if maintaining an annulus pressure higher than the injection pressure may cause damage to the well or the formation. However, it would be better if this flexibility was explicitly approved in the guidance document.

   EPA's reasoning assumes that the failure will occur in the long string tubing and when/if it occurs, the CO2 will be forced to stay in the tubing if the tubing-casing annulus pressure has a greater pressure. This could occur, however all possible failure modes of the well must be examined and their effect. In a tubing leak, once the tubing-casing annulus and tubing pressures equalize, the CO2 could easily flow into the annulus anyway. Likewise, if the packer fails, the packer fluid in the tubing-casing annulus will flow downward and into the formation. The CO2 in the wellbore would replace the packer fluid when it leaves the annulus.

   The nature of CO2 itself requires that the surface pressure be high to keep the CO2 supercritical and avoid phase changes in the tubing. This is different than injecting a dense fluid and the EPA requirement means an operator needs to have a pressure on the annulus at the top of the well that is significantly over formation fracture pressure and likely to be over the formation fracture pressure for the entire length of the well. The result of a casing leak with an annulus pressurized to this degree could inject packer fluid into formations, possibly including USDWs.

   Furthermore, applied casing pressure creates ballooning and will result in additional stress cycles on the cement sheath over the life of well. Stress cycles – due to periodically adding pressure over time - may debond the cement interfaces and induce fractures in the matrix. Wellhead injection pressure is likely to be at least 1200 psi for a CO2 injector which could require approximately 1500 psi applied casing annulus pressure. Jackson, et al, 1996, indicate a change in diameter of 0.003 inches is sufficient to create a microannulus leakage pathway. Applied casing pressure of 1500 psi with a packer fluid of 8.6 ppg density in a 7", 26 ppf casing may create up to 0.0034 inches based on API 10TR, Cement Sheath Evaluation, 2007, assuming normal pore pressure conditions. This means that operating with a higher pressure on the annulus and the ballooning effect associated with periodically adding pressure may over time reduce the cement bonding between the long-string and the cement behind the long string.

Additionally, API Recommended Practice (RP) 90 (adopted by BOEMRE at 30 CFR Part 250 "Annular Casing Pressure Management for Offshore Wells", 2010) has a warning against applying an annular pressure that can damage the well integrity, i.e., cement sealing performance. In effect, the EPA guidance violates this federal rule.

The integrity damage warning (cement stress cracking) appears in the following sections:

1. 5.4.6 Subsequent Bleed-down and Build-up Tests (p.15,)
2. 7.5.7 Subsequent Annular Pressure Evaluation Tests (p.29)
3. 14.1.4 Cementing Program (p.83)

In addition, RP 90 says operator-induced pressures during injection operations can contribute to the above stress loads (14.1.1 Casing Design, p.82, 2nd paragraph and 3rd bullet where "injected fluids" could represent applied pressure to the annulus).

API recommends EPA include in its Guidance a more common and safe practice of maintaining a positive pressure of 200-250 psi which is not detrimental to the integrity of the wellbore. This gives the operator an ability to monitor the integrity of the outer most casing. A continuous positive pressure with slight fluctuations due to temperature variations indicates that the long-string integrity is secure. Also, the lack of similar magnitude injection pressure in the tubing-casing annulus indicates that the tubing and packer are functioning as designed. An operator's focus should be on monitoring the annulus pressure and liquid height as this will tell them how effectively the casing, tubing and packing are holding.

<u>References</u>

Jackson, P.B., Murphey, C.E., 1993, *Effect of Casing Pressure on Gas Flow Through a Sheath of Set Cement*, SPE #25698, SPE/IADC Drilling Conference, Amsterdam

API Technical Report 10, *Cement Sheath Evaluation*, 2007

2) The requirement for the *long-string* to be cemented to surface in every situation should be modified. Consistent with Section 2.5.1 of the Guidance allowing alternatives if cementing to the surface cannot be done, the statement on page28 should read "long-string should be cemented to the surface if possible". The issue is that it isn't always possible to circulate cement to surface for various reasons. Staging cement jobs to step the level of the cement to the surface with two or more jobs is common practice when it is known or suspected that it will be difficult or impossible to circulate cement to surface in one attempt. Multiple staging jobs to

position cement behind the long-string can be planned when/where necessary but success is never guaranteed. Subsequent perforating and cement-squeeze jobs can also be used to attempt to circulate cement to surface but again, there are no guarantees. Therefore, "if possible" should be added to the requirement.

3) Similar issue to #2, above, EPA should not require *surface casing* to be cemented to surface in every case. EPA should amend the Guidance to provide for top-off. If cement does not reach the surface or falls back when the pump stops, it's common to pump cement down from the surface and into the outside of the surface casing with a 1" pipe. This is commonly referred to as "1 inch or top-off with 1 inch". It is a very common practice because the cement level often falls due to its weight as the cement fills voids in the wellbore on the outside of the casing. The process is common and EPA should refer to the process in the Guidance.

4) Page 28 states, "Injection pressure must **not exceed 90%** of fracture pressure of the injection zone" during injection operations. This limitation is unnecessary because the CO2 EOR industry has proven for decades that periodically exceeding fracture pressure of a permitted injection zone during the cycling of injection operations was safe. The ability of the permeable rock in the injection zone to fracture and confine the fracture within the designated injection zone is well known and understood. The nature of the caprock to resist fracturing at the controlled injection pressures during injection operations into the designated injection zone below the caprock is also well known and understood. Prudent operation in injection operations prohibits formation damage due to unnecessary or excessive injection pressures. Operators don't desire to operate with practices that will damage their operation, reduce safety and hurt them financially. At a minimum, the Guidance should add the phrase "at the perforation" to the requirement since the fracture pressure can vary vertically through the injection zone.

5) The requirement that the long-string extends "to" the injection zone should be clarified in the Guidance. The phrase "to the injection zone" is extremely vague and could be perceived as just penetrating the injection zone when optimization of injection would entail the long-string extending completely through the injection zone and possibly into the layer below the injection zone. Accordingly, the Guidance should clarify that this means that the long string (or long-string with liner – see later comment #1 below) must "extend *at least* to the injection zone".

6) The GS rule calls for operators to maintain mechanical integrity of the well "at all times" [§146.88(d)]. Although the intent of the EPA is to ensure that the operator is prudent with injection operations, it is possible a component will fail over the multi-decade life of a well and the operator should be charged with proactive issue identification and resolution. The Guidance should make clear that operator should be tasked with putting a program in-place to monitor injection operations and to respond when a failure occurs to repair the failure and to regain any lost mechanical integrity. No operator can ensure mechanical integrity of a well at all times. All operators should ensure that a plan is in-place to minimize failures and to respond immediately when and if a failure does occur.

7) The limitation that caprock will never be able to be fractured is excessive as a categorical statement. Cases of very long caprock intervals should permit some latitude to have a fracture extend into it by some percentage.

Comments on EPA Recommendations within the Well Construction Guidance

1) The EPA GS rule is silent on the use of liners, which have been proven to be safe and effective. Liners installed on the bottom of the well and across the injection zones are common and are very effective for downhole controlled dispersion of designated injectants. It is very common to install a liner on the bottom of the well if the wellbore construction and wellbore integrity are sufficient without adding another complete string of casing from the surface and through the injection zone. When a liner is lowered to the bottom of the wellbore, it is securely placed above the bottom of the casing and cemented behind the liner. This is a proven, very safe and successful method to ensure that the injectant is confined within the wellbore and the designated injection zone.

   If wording allowing the use of liners is not added to the Guidance, all future injection wells will require long-strings with no exceptions. If the long string fell short of the storage formation by ten feet, it may not be possible to add another long string, and the well would have to be abandoned if liners were not allowed. A third string is not always possible technically and commercially.

2) On page 22 (section 2.6) EPA states that:

   > "Most well logs used to measure the quality of the cement bond perform best when run directly against the casing. Therefore, to obtain the best measurement of the quality of the cement bond through the confining layer as possible, EPA recommends placing the packer near the top of the confining layer to obtain the best results."

   API notes that many cement logs do not need to run directly against the casing to measure the integrity of the cell, although some do. Additionally, packer placement can impact the ability to test wellbore integrity, the mechanical stress on well components during operation, and the risks to tools and equipment during well intervention. Because of this, API recommends the paragraph be changed to read as follows:

   > "Well logging of the confining zone can be affected by packer placement. Therefore, to obtain the best measurement of the quality of the cement through the confining layer as possible, while not creating unnecessary risks, EPA recommends placing the packer near the top of the confining layer to obtain the best results, recognizing that this approach may need to be modified based on well-specific issues so as to maximize measurement quality while not creating additional risks to well integrity or downhole equipment."

Class VI Area of Review (AoR) Evaluation and Corrective Action Guidance Comments

1) In the Class VI rule, the EPA has defined "the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The AoR is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected CO_2 stream and displaced fluids and is based on available site characterization, monitoring, and operational data as set forth in § 146.84". Yet in the Guidance (page 32), the AoR is effectively defined in terms of "pressure front" where "pressure front" is described as the "pressure increase of sufficient magnitude to force fluids from the injection zone into the formation matrix of a USDW through a hypothetical open conduit". This definition results in a very conservative AoR and may be more appropriate for use in a sensitivity analysis as a boundary condition. API recommends EPA adopt an approach that better considers the site specific risk factors, rather than this worst case scenario.

2) Section 4.2.1 (pg 50) states "well casing and cement must be assessed to see if they are compatible with carbon dioxide." This statement is directed to wells that cannot be verified as being properly plugged. This statement suggests that in these wells, materials that are deemed incompatible (by some undefined criteria) would somehow require corrective action despite the weight of evidence associated with CO_2 EOR operations that show compatibility is not a real issue in most cases.

3) The guidance on abandoned well field testing provided in Section 4.2.2 and 4.3.1 (pg 51 and 52) is likely to preclude use of most abandoned oil and gas field as CO_2 storage sites. Costs of verifying the adequacy of the plugs (which has not been clearly defined) of abandoned wells could simply be too high for a commercial venture.

4) Section 4.3.1 (pg 54) references wells that were "plugged and abandoned improperly" as requiring corrective action. While that is accurate in one sense, there will be many wells that were plugged in compliance with all legal and regulatory requirements (either those in effect at the time the well was plugged or today) that may require corrective action when the implications of CCS are considered on a site specific basis. The requirements for a storage site to prevent fluid movement under these rules are different than those that might be associated with typical well abandonment operations. Those differences don't make the prior plugging operations improper nor out of compliance and the Guidance needs to reflect that.

5) Section 4.4 (pg 56) states that records of any remedial cementing (corrective action) on plugged wells must be submitted with the Class VI injection permit application. It is highly unlikely that a prospective storage site operator will perform corrective action work prior to obtaining the injection permit due to the financial commitment involved. A more workable approach would be to issue the permit with the necessary corrective actions as a permit condition, a logical extension of the phased corrective action approach already included in the rules.

6) EPA should include a distance scale on all the figures it has used to better illustrate the results.

7) API would like to alert EPA to the possibility that the equation used to calculate the pressure front is flawed. The flaw comes from the derivation of the equation. The equation presented in the guidance does not properly handle the density difference between the injection formation fluid and the USDW fluid. By setting the heads equal in the two wells in example in Box 3-2, of the Guidance, EPA assumes that the flow between the formation occurs when the fluid levels in the well are equivalent (1830m). However the actual flow does not occur at 1830M it occurs at the USDW interval at 1615m. Instead of head, one should consider the situation where the pressure in the USDW (at 1615m) is equal to the pressure in a conduit open to the USDW and the injection formation at 1615m. Considering the problem this way we can develop the equation this way:

$$P_{OC,\,1615} = P_{i(1615\text{-}1712)} + DP_{if} = P_u = 2108419\text{Pa } (2.11\text{MPa}) \quad \text{[Equation 1]}$$

Where:

$P_{OC,\,1615}$ = Final pressure in the open conduit at 1615m to cause flow of brine into the USDW

$P_{i(1615\text{-}1712)}$ = The existing pressure at 1615m due to the pressure in the injection formation

DP_{if} = The change in pressure needed to cause flow into the USDW at 1615m

P_u = The existing pressure in the USDW at 1615m (the pressure that must be overcome to flow)

$P_{i(1615\text{-}1712)}$ is based on the pressure due to the height of the brine column above 1615m and is calculated by multiplying that height by the density of the brine and gravitational acceleration:

$$P_{i\,(1615\text{-}1712)} = (1712\text{m}-1615\text{m})*9.0866\text{m/s}^2*1012\text{kg/m}^3=962655\text{Pa}$$

Using this to solve equation 1 for DP_{if} we find that the pressure change needed to cause flow at 1615m is 1145764Pa or a change in column height (using the density of brine) 115.45m. The final injection formation pressure needed to cause leakage into the USDW is:

$$P_{if} = P_{i0} + DP_{if} = 13397777\text{ Pa} + 1145764\text{ Pa} = 14543541\text{Pa } (14.54\text{MPa})$$

This is equivalent to a brine-head of 1827.45m

This is slightly smaller than the 14.56MPa (1830m) calculated by the suggested equation and leads to a larger AOR. If EPA intends to use head as a means for calculating pressure in the subsurface it needs to consider only one fluid and convert all measured fluid levels to heads using a single density. C.W. Fetter provides an explanation and equations for this on page 220 of the 1993 edition of *Contaminant Hydrogeology*. If one assumes immiscible fluids the equation to convert the freshwater head in the USDW to a "brine head" is:

$$h_{ubrine} = \frac{\rho_u h_u}{\rho_i} - \frac{\rho_u - \rho_i}{\rho_i} z_u \quad \text{[Equation 2]}$$

Keeping this equation in mind we can go forward with the derivation of an equation to calculate the pressure in the injection zone needed to cause flow into the USDW at 1615m

$$h_u = \frac{P_u}{\rho_u g} + z_u \text{ [Equation 3]}$$

Where h_u is a head based on USDW fluid density.

$$h_i = \frac{P_i}{\rho_i g} + z_i \text{ [Equation 4]}$$

For flow the heads must be numerically equal and be calculated using the same fluid densities. Setting Equation 2 equal to Equation 4 and rearranging for P_i one gets:

$$P_i = \rho_u h_u g - (\rho_u - \rho_i) z_u g - \rho_i z_i g \text{ [Equation 5]}$$

Inserting the definition of h_u from equation 3 into equation 5 one ends up with:

$$P_i = P_u + \rho_i g (z_u - z_i) \text{ [Equation 6]}$$

Which also calculates a pressure, P_{if}, equal to 14543541Pa (14.54MPa). While this difference is minor the error is magnified with larger differences between the USDW and brine density.

Class VI Project Plan Development Guidance Comments

<u>General Comments</u>

1) The Guidance is ambiguous regarding how an operator would add a procedure that was not in one of the original plans.

<u>Area of Review and Corrective Action Plan</u>

1) This section requires that the AoR be reevaluated at least every five years unless triggered earlier by unexpected site conditions or operational changes. The Guidance is silent on the timing in which such a discovery is to be reported to EPA. Additionally, it is unclear whether work must stop completely in between corrective actions, AoR reevaluation and plan approval in the event that one of the stated conditions requiring a less than five year assessment occurs.

2) The Guidance is also silent regarding the handling of corrective actions conducted in an emergency that may not have been previously approved in the plan.

<u>Testing and Monitoring Plan</u>

1) The additional detail that is recommended in the Guidance is tantamount to increased project costs and schedules. Considering the level of detail required by these Plans, the land surrounding GS projects will be some of the most analyzed parcels in the country.

Injection Well Plugging, Post-Injection Site Care, and Site Closure Plans

1) The Guidance does not mention whether a certificate of closure that is issued by the Program Director could serve as the initializing instrument for a long-term liability program.

Emergency Response and Remedial Response Plan

No comment.

Class VI Site Characterization Guidance Comments

Page 50

The list of cations and anions to be analyzed needs to include:
Al, SiO2 (aq), Ba, Sr, Fe++, Fe+++, HCO3, CO2 (aq), H2S (aq)
H2S will depend whether the field was an oil field or not.

Page 53

A somewhat friendlier version of reactive transport modeling is the XT1 and XT2 models of the Geochemist WorkBench (GWB).

Page 92

Vertical permeability measurement is mentioned above Figure 3-29. It is not related to the other context. All the other equations mentioned in the section do not show any directional permeability. Either removing the sentences related to vertical permeability or writing the equations 3-14 and 3-15 in directional format distinguishing horizontal transmissibility and vertical transmissibility is recommended.

Page 93-98

Measurements of various parameters: This is just to note that CCP3 is performing a study on relative permeability, capillary pressure, and possibly on wettability specific to CO2. It is expected to be completed in 2011 or by early 2012. It will be very helpful to reference the study results once they are available.

Page 101

Mobility definition: Mobility is phase permeability divided by its viscosity, not phase relative permeability divided by its viscosity. In equation 3-24, k_i should be phase effective permeability defined as $k*k_{ri}$ where k is the permeability and k_{ri} is the phase relative permeability.

Page 105

Skin determination: A similar equation to Eq. (3-29) for oil well tests can be used to determine skin for oil wells (Dake, L. P. *Fundamentals of Reservoir Engineering*)

$$S = 1.151\left(\frac{\left(Pi - P_{wf(1hr)}\right)}{m} - \log\frac{k}{\phi\mu c r_w^{\ 2}} + 3.23\right)$$

Page 111
For consistency, the term "Structural and stratigraphic traps" needs to be in Italic. Other trapping mechanisms (residual trap, solubility trapping, mineral trapping) are all in Italic.

Page 113
Under dynamic models, it is written that dynamic models are "generally considered applicable for estimating carbon dioxide storage capacity after initiation of carbon dioxide injection". Reservoir simulation is more useful when used before the injection to estimate and optimize the CO2 injection.

Page 114
In Section 3.10, there is absolutely no mention of oil/gas accumulations as evidence for confining zone integrity. Though this is not a direct measurement of seal integrity, it should be considered in the evaluation of the seal (both for CO2 storage in depleted oil/gas reservoirs and for CO2 storage with offsetting oil/gas reservoirs nearby which share the same seal).

701 Pennsylvania Avenue, N.W. | Washington, D.C. 20004-2696 | 202.508.5000 | www.eei.org

Power by Association™

Edison Electric Institute

May 31, 2011

Submitted via E-mail to GSRuleGuidanceComments@epa.gov

Subject: *Draft Guidance Documents: Geologic Sequestration of Carbon Dioxide: Underground Injection Control Class VI Wells*

Dear Sir or Madam:

The Edison Electric Institute (EEI) submits the attached consolidated comments on four draft guidance documents addressing the Underground Injection Control (UIC) Class VI Program issued by the Environmental Protection Agency (EPA) in March 2011: Site Characterization Guidance (EPA 816-D-10-006); Area of Review Evaluation and Corrective Action Guidance (EPA 816-D-10-007); Well Construction Guidance (EPA 816-D-10-008); Project Plan Development Guidance (EPA 816-10-010). These documents are intended to provide guidance to permitting authorities and owners and operators of Class VI wells regarding EPA's final rule under the UIC Program for carbon dioxide geologic sequestration wells. *See* 75 *Fed. Reg.* 77230 (Dec. 10, 2010).

EEI is the association of shareholder-owned electric companies, international affiliates and industry associates worldwide. Our U.S. members serve 95 percent of the ultimate customers in the shareholder-owned segment of the industry, and represent approximately 70 percent of the U.S. electric power industry. Many of our members are actively involved in the research, development, demonstration and deployment of technologies to capture carbon dioxide from electricity production and inject it into geologic formations for long-term storage, activities covered by the draft guidance documents. Carbon capture and storage is a critical element in the full portfolio of technologies and measures to reduce greenhouse gas emissions.

EEI appreciates the opportunity to provide comments. Questions may be directed to Emily Fisher ([redacted] or Dr. Karen Obenshain [redacted]

Sincerely,

Emily Sanford Fisher

Emily Sanford Fisher
Director, Legal Affairs, Energy & Environment

Attachment

Edison Electric Institute

CONSOLIDATED COMMENTS OF EDISON ELECTRIC INSTITUTE ON THE ENVIRONMENTAL PROTECTION AGENCY'S DRAFT GUIDANCE REGARDING SITE CHARACTERIZATION, AREA OF REVIEW AND CORRECTIVE ACTION, WELL CONSTRUCTION, AND PLAN DEVELOPMENT UNDER THE UNDERGROUND INJECTION CONTROL CLASS VI PROGRAM

May 31, 2011

The Edison Electric Institute (EEI) submits these consolidated comments on the following four draft guidance documents for the Safe Drinking Water Act (SDWA) Underground Injection Control (UIC) Class VI program issued by the Environmental Protection Agency (EPA or Agency) in March 2011: 1) Site Characterization Guidance for Owners and Operators (EPA 816-D-10-006) (Site Characterization Guidance); 2) Area of Review (AOR) Evaluation and Corrective Action Guidance for Owners and Operators (EPA 816-D-10-007) (AOR Guidance); 3) Well Construction Guidance for Owners and Operators (EPA 816-D-10-008) (Well Construction Guidance); and 4) Project Plan Development Guidance for Owners and Operators (EPA 816-D-10-012) (Project Plan Guidance) (collectively, draft Guidance Documents). The final Guidance Documents, along with the December 2010 guidance regarding financial responsibility (EPA 816-10-010), will complement EPA's final rule for the Federal Requirements under the UIC Program for Carbon Dioxide Geologic Sequestration (GS) Wells. 75 *Fed. Reg*. 77230 (Dec. 10, 2010) (Final UIC Class VI Rule).

EEI has actively participated in EPA's development of the UIC Class VI program. On February 8, 2011, EEI submitted comments on the draft guidance regarding financial responsibility for Class VI wells. EEI submitted comments to the Agency on October 15, 2009, on the Notice of Data Availability (NODA) and Request for Comment related to the Agency's proposed regulations for injection and GS of carbon dioxide (CO_2) under the authority of the SDWA UIC program, issued in July 2008 in Docket No. EPA-HQ-OW-2008-0290, 73 *Fed. Reg*. 43491 (July 25, 2008). EEI also submitted pre-rulemaking comments to the Agency on May 15, 2008, provided oral and written testimony at EPA's September 30, 2008, public meeting on the proposed rules, and submitted written comments on December 24, 2008. EEI also provided testimony at the public hearing on the NODA on September 17, 2009, and participated in the development of the proposed rule via webinars held in April and May 2009. These comments and testimony are incorporated by reference herein.

EEI appreciates the EPA's extension of the comment deadline on these draft Guidance Documents in response to requests from EEI and others in early April.

I. Introduction

As we have stated previously, EEI views carbon capture and storage (CCS) as a critical element in the full portfolio of technologies and measures needed not only to reduce CO_2 emissions, but also to ensure continued affordable and reliable electric service to customers throughout the U.S. EEI thus supports the development of clear, defensible and appropriately tailored regulatory regimes that will facilitate development of, and investment in, CCS technology and projects while protecting against potential environmental risks. The Final UIC Class VI Rule forms the basis of this emerging regulatory regime, and the final Guidance Documents will determine whether the regulations foster or hinder the development and deployment of CCS.

These comments are divided into the following sections. First are general comments that apply to all four draft Guidance Documents. Subsequent sections provide specific comments, in turn, on each of the four drafts.

II. General Comments On All Four Draft Guidance Documents

As a general matter, it is premature for the Agency to issue detailed guidance in light of the fact that the UIC Class VI program is in the early days of its implementation, with no Class VI permits issued – and not more than one applied for – to date. It is important to provide guidance to state permitting authorities that seek primacy for Class VI wells, especially given the lack of experience in issuing permits for the injection and storage of CO_2. The better approach, however, is for EPA to provide informal guidance as needed to state permitting authorities on a case-by-case basis now, and issue formal guidance documents later, after regulators and industry have a track record of experience with Class VI permits. Such an approach would be consistent with the "adaptive approach" that underpins the Class VI rule itself, as EPA emphasized in the preamble to the Final UIC Class VI Rule:

> EPA agrees with commenters who supported an adaptive approach to the UIC rulemaking for [geologic sequestration] … EPA also believes that an adaptive approach enables the Agency to make changes to the program as necessary to incorporate new research, data and information about [geologic sequestration] and associated technologies (e.g., modeling and well construction). This new information may increase protectiveness, streamline implementation, reduce costs, or otherwise inform the requirements for … injection of CO_2.

75 *Fed. Reg.* at 77241. As noted in prior comments, EEI supports an adaptive approach to CCS regulation.

To the extent that EPA believes that it is appropriate to issue guidance at this time, EPA should mimic what the Class VI rule requires instead of going beyond it. For example, EPA acknowledges in the "Disclaimer" to the draft Guidance Documents that it is going beyond the minimum requirements of the Final UIC Class VI Rule. Consistent with the adaptive approach EPA espoused in that rule, the Agency does not state that the more stringent requirements found in the draft Guidance Documents are based on new "research, data and information." *See id.* Accordingly, the Agency is proposing to "adapt" a regulatory regime to make it more stringent in the absence of any justification, and is doing so at an extremely accelerated pace, far ahead of EPA's stated six-year schedule for revising the UIC Class VI requirements. *See id.* **It is highly inappropriate for EPA to issue guidance that goes beyond the requirements of a rule that has not yet been implemented, let alone used commercially.**

Despite the fact that each draft Guidance Document purports to be non-binding and notes that "EPA and state decision makers retain the discretion to adopt approaches on a case-by-case basis that differ from this guidance where appropriate," **as a practical matter permit writers will be apt to comply with all aspects of the final guidance because the regulatory regime is new and they lack experience in its administration.** This would undermine a key tenant of the Final UIC Class VI Rule, which emphasizes the tailoring of requirements to the unique nature of a specific GS project to mitigate risks and minimize regulatory burdens. **EPA's goal of promoting consistent approaches to permitting GS projects across the U.S. (75 *Fed. Reg.* 77247) must be balanced with the importance of tailoring requirements to the specific geology of a proposed storage site.** Given that there is little permitting activity in the U.S. at this time, EPA's seeming preference for ensuring consistency via the Guidance Documents is misplaced.

The draft Guidance Documents could be read to suggest that EPA believes, contrary to the scientific record, that properly regulated and sited geologic storage projects will be unsafe and ineffective. A good example is EPA's statements regarding tectonic history in the site characterization guidance. *See* Site Characterization Guidance at 7-8. There, EPA suggests that earthquakes pose a credible risk to loss of containment, when the data indicate the opposite.[1] And while an initial seismic assessment must be a prudent part of any site characterization (and the same subject is already addressed in the Final UIC Class VI Rule – *see* § 146.82(3)(v)), belaboring the point in extensive and gratuitous guidance commentary is neither necessary nor wise – in large part because it will only needlessly serve to undermine public confidence in CCS.

The draft Guidance Documents suggest that the Class VI program is largely commercially unworkable. For example, commercial operators generally cannot get financing for the first well drilled (monitoring well, injection well or otherwise); commercial operators instead need to get financing at the beginning of an entire project. Yet the Final UIC Class VI Rule, as supported by the guidance, envisions a scenario under which wells are permitted one at a time (since there is

[1] *See, e.g.*, C. Davidson, "Tectonic Seismicity and the Storage of Carbon Dioxide in Geologic Formations," Pacific Northwest National Laboratory ("The results are encouraging; only 0.2% of U.S. emissions occur over areas of high risk, located in Southern California and the Midwestern New Madrid fault zone. For these areas, consideration of seismic hazards may result in selection of injection sites a bit farther from the source in order to ensure injection into a lower-risk area. However, 96% of major CO_2 sources in the 48 contiguous United States, representing 98% of emissions in the same region, fall in areas of negligible or low risk …."), *available at* http://uregina.ca/ghgt7/PDF/papers/poster/290.pdf; Bellona CCS Web (describing the possible release of CO_2 due to an earthquake in the injection zone as a "myth"), *available at* http://www.bellona.org/ccs/Artikler/storage_safety.

no area permit), with each well requiring the submission of voluminous data – including, most troubling, data on subsurface and surface geology beyond the AOR. Yet after that well is drilled and evaluated, the entire project plan may have to be discarded, with the permitting clock reset, perhaps putting a project back by years. Such an approach to permitting would frustrate, if not impede, applications for project finance. See also pp. 11-12, *infra.*

EPA should review all four draft Guidance Documents collectively to ensure uniformity and consistency with the Final UIC Class VI Rule. For example, the AOR Guidance includes the following statement about site characterization: "Extensive site characterization data are required to be collected for proposed GS projects." AOR Guidance at 24. The term "extensive" does not appear in the Final UIC Class VI Rule or the separate Site Characterization Guidance.

Finally, as a procedural matter, the piecemeal issuance of guidance makes it difficult for the public and interested parties to provide thoughtful and comprehensive comments on what now appears to be an evolving Class VI regulatory regime. These four draft Guidance Documents follow issuance of the prior financial responsibility guidance, and EPA has indicated that more guidance documents are in the works. The four new draft Guidance Documents make specific reference to a soon-to-be-issued document on testing/monitoring. **Because all of the Guidance Documents are interrelated, it would be preferable for EPA to issue all of them together or, in the alternative, allow additional comment on previously issued guidance as subsequent guidance is issued.**

III. <u>Comments On Specific Guidance Documents</u>

A. Site Characterization Guidance (EPA 816-D-10-006)

The draft Guidance introduces and defines terms, such as "brine," that are not defined in the Final UIC Class VI Rule. *See* Site Characterization Guidance at xi. Instead of introducing and defining new terms, the Guidance should incorporate by reference the definitions that exist in the Final Rule.

The Final UIC Class VI Rule provides that the applicant must provide "[g]eologic and topographic maps and cross sections **illustrating** regional geology, hydrology, and the geologic structure **of the local area.**" 40 C.F.R. § 146.82(a)(vi) (emphasis added). The draft Site Characterization Guidance turns this common-sense requirement for an "illustration" of local geology into detailed obligations for the submission of data addressing the geology **outside the AOR.** *See* Site Characterization Guidance at 5. The draft Guidance states that site characterization will occur on "two scales": "In the regional-scale demonstration, the owner or operator will compile geologic information about the region surrounding the AoR"; then the applicant must also submit detailed data on the AOR. *Id.* Given the large areal extent of the AOR, requiring anything more than "illustrative" local and regional geology is unnecessary, absent some showing that this information would lead to better protection of Underground Sources of Drinking Water (USDW). Moreover, "illustrative" information about local geology is likely all that can be obtained by permit applicants, given that geologic maps produced by the U.S. Geologic Survey and maps indicating the location of USDW vary in terms of detail and scale. Accordingly, the language regarding local and regional geology should be deleted.

The draft Guidance also "recommends" that applicants provide a wealth of data on USDW, including those outside of the AOR. *See id.* at 10 (an applicant should provide data on "all USDWs in the AOR and **the region**, and whether they are currently being used for drinking water") (emphasis added). Non-AOR data are irrelevant to ensuring adequate containment within the subject geologic storage site, and requiring it would go well beyond what is required in the Final UIC Class VI Rule. Its inclusion in the draft Guidance suggests that permitting for Class VI will devolve into never-ending quests for region-wide geologic data that have nothing to do with protecting USDW in the target site.

EPA suggests that commercial project data availability should be based upon what is available from research projects here and abroad:

> Data for formations with potential hydrocarbon assets may be available from state oil and gas commissions. This is certainly the case for a number of <u>pilot projects</u>. At Teapot Dome in Wyoming (Freidmann and Stamp, 2005), <u>researchers</u> had access to existing geological, geophysical, geomechanical, and geochemical data. At the Ketzin site (Forster et al. 2005) and the Schweinrich anticline (both in <u>Germany</u>) (Meyer et al., 2008), information such as seismic data, cores, well logs, and wireline logs were available

Id. at 22 (emphasis added). While various CCS research projects around the globe may have relied upon a wealth of data on a site-by-site basis, these references are irrelevant to permitting U.S. sites under the UIC program. References to foreign sites are inapposite as such sites are not subject to U.S. law, particularly laws and regulations regarding data collection and protection, including trade secrets. In addition, such data will be very difficult to obtain if the AOR includes active hydrocarbon or mineral extraction activities, as information relating to such activities may be considered confidential business information.

Moreover, there is a fundamental difference between the research projects referenced in the Site Characterization Guidance (which would be permitted under Class V in the U.S.) and commercial wells (which will be permitted under Class VI). By definition, Class VI wells are commercial and "are not experimental in nature." 40 C.F.R. § 144.6(f). The goal of Class V wells is to advance research and development of CCS. The goal of Class VI wells is to store volumes of CO_2 captures from commercial projects, consistent with legal or regulatory obligations to reduce GHG emissions. Data requirements that would be appropriate in the research and development context should not be imposed on commercial projects. The Guidance's reference to research and pilot projects is both inappropriate and inconsistent with the status of Class VI as a commercial well class.

Section 3 of the Site Characterization Guidance contains detailed information regarding tools and techniques to assess specific site geology within the AOR. Section 3 would be helpful if it were intended for publication as a research paper on a review of all potentially relevant technologies that could be used to characterize a site without regard to 1) costs, commercial practicality, usability and the relevance of data so acquired, and 2) suitability of specific technologies for specific sites. Section 3, however, is inappropriately included in permitting guidance. Listing and describing each possible site characterization technique suggests that all must be conducted at each site. As contemplated by the Final UIC Class VI Rule, EPA should leave specific site characterization technologies to be vetted between the applicant and permit writer on a case-by-case basis.

B. AOR Guidance (EPA 816-D-10-007)

The AOR provisions of the Final UIC Class VI Rule and the AOR Guidance are premised on the generic assumption of preexisting geologic conduits between the target formation and USDW. Typically, there are hundreds of feet of confining layers between the target formation and other formations. **Published data from existing projects does not support EPA's assumption of preexisting geologic conduits between the target formation and USDW.** The unlikely existence of such a phenomenon should be vetted in the context of a specific permit application, but EPA should not assume that such conduits exist in the first instance. Geophysical analysis is the only way to determine whether a transmissive fault exists. EPA is taking the worst-case approach here, imposing undue burdens on all projects.

The AOR Guidance similarly is premised in part on assumptions regarding the "movement of non-potable water (*e.g.*, brine) out of the injection formation into a USDW as caused by **elevated formation pressures** induced by injection." AOR Guidance at 2 (emphasis added). A recent paper calls this assumption into question. *See* Q. Zhou, "On Scale and Magnitude of Pressure Build-Up Induced by Large-Scale Geologic Storage of CO_2," Greenhouse Gas Science & Tech., 1-11-20 (2011). Following the "adaptive" approach established for the Final UIC Class VI Rule, EPA should take into account the Zhou paper in the AOR Guidance.

A likely outcome of EPA's approach is that AORs will be quite large; EPA itself acknowledges that an AOR will be "potentially large." *See* AOR Guidance at 2. For a commercial project, a "potentially large" AOR that is decoupled from the legal requirement to protect relevant USDW will delay, if not impede, projects unnecessarily. The size of the AOR should be dictated by a site-specific assessment of what is needed to protect USDW.

The draft Guidance introduces and defines terms, such as "capillary pressure," that are not defined in the Final UIC Class VI Rule. *See id.* at xi. The final Guidance should incorporate by reference the definitions that exist in the Final UIC Class VI Rule.

The draft Guidance assumes that CO_2 subsurface modeling requires more complicated computational modeling than hazardous waste (Class I). AOR Guidance at 2 ("GS computational modeling for Class VI injection wells is more complex than methods used to delineate the AoR for other injection well classes"). CO_2 is neither a hazardous substance nor a hazardous waste under U.S. law. The guidance thus creates uncertainties to the extent that it suggests, intentionally or otherwise, that CO_2 is hazardous. At minimum, statements such as that cited above are not helpful and are inappropriate for a guidance document.

The guidance makes the following statement about area permits:

> EPA anticipates that, in most cases, multiple injection wells will be operated within a single GS project. **An individual UIC Class VI injection well permit must however be separately obtained for each injection well, as area permits are not allowed under the GS Rule.** Nevertheless, if approved by the UIC Program Director, AoR delineation and corrective action activities may be performed comprehensively for all wells included within a single project. EA recommends that AoR delineation models account for all wells injecting carbon dioxide into the injection zone, including any injection wells associated with other UIC well class injection projects.

Id. (emphasis added). Area permits should be allowed under the Final UIC Class VI Rule. It is imperative that site permitting be considered comprehensively. Addressing permitting for individual injection wells in multiple-well projects on a well-by-well basis is counterproductive in most instances; it certainly will lead to unnecessary and duplicative project costs, thereby frustrating the advancement of commercial projects. Multiple injection wells at a project will generally be operated in a cooperative manner, so it only makes sense that they be permitted together, too.

The draft Guidance impermissibly discounts the fact that computational modeling must be based on "available" data. The Final UIC Class VI Rule states that the "area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on **available** site characterization, monitoring, and operational data." 40 C.F.R. § 146.84(a) (emphasis added). The draft Guidance document drops the critical notion of data "availability," however. *See* AOR Guidance at 6-7 ("A computational model is a mathematical representation of the GS project and relevant features, including injection wells, sit geology, and fluids present."). The word "available" appropriately delineates the scope of the modeling.

The draft Guidance provides "**background** on the fundamentals of computational modeling in order to provide the necessary background for owners and operators …" *Id.* at 6 (emphasis added). A tutorial on computational modeling is inappropriate for a guidance document, particularly in light of the ever-evolving nature of modeling. EPA would not be able to update this section of the Guidance continually, which could lead permitting authorities to reject improved models that are not consistent with the information provided in the Guidance. All ancillary information should be deleted from the guidance, including all of section 2.1.

Section 3 of the guidance, dealing with the use of computational modeling for AORs specifically, includes advisory statements that would only delay and confuse the permitting process for commercial projects. An example is the following statement: "Thorough characterization of multiphase flow parameters is also **recommended** in order to properly inform the computational modeling." *Id.* at 25 (emphasis added). A recommendation such as this would become a *de facto* requirement for permits – despite the fact it does not appear in the Final UIC Class VI Rule. Consideration of multiphase flow parameters may be wholly irrelevant in a specific situation. The final Guidance should emphasize the importance of site-specific requirements and should avoid broad, sweeping advisory statements that may delay and complicate permitting without ensuring increased protection of USWD.[2]

Section 5 of the guidance addresses AOR reevaluation. It repeats the Final UIC Class VI Rule's provision of a minimum fixed frequency, not to exceed five years, at which time the owner or operator must reevaluate the AOR. *See* 40 C.F.R. § 146.84(b)(2)(i). A rigid five-year reevaluation requirement would stall commercial projects; the AOR is "potentially large," as EPA has acknowledged, and the reevaluation process itself will be time-consuming and costly. Moreover, a rigid five-year reevaluation requirement would not provide additional protection of USDW for well-sited, -designed and -operated projects – and only such projects will receive permits to begin with. EPA should revise section 5 of the AOR Guidance to provide that if the computational modeling demonstrates data agreement with the model after the first five-year period, the reevaluation period is relaxed for each subsequent period.

[2] Comparable examples abound throughout the document. For example, EPA recommends the use of remote sensing/satellite data to identify artificial penetrations. *See id.* at 43. Remote sensing data should only be used on a case-by-case basis.

C. Well Construction Guidance (EPA 816-D-10-008)

This draft Guidance introduces and defines terms, such as "brine," that are not defined in the Final UIC Class VI Rule. *See* Well Construction Guidance at vi. Again, instead of introducing and defining new terms, the Guidance should incorporate by reference the definitions that exist in the Final UIC Class VI Rule.

In addition, statements about the nature of CO_2, such as the following, should be deleted:

> As carbon dioxide is different than other injection previously regulated by the UIC Program, the GS Rule sets requirements specific to carbon dioxide. Because carbon dioxide is less dense than most subsurface fluids, it is buoyant and will tend to migrate to the top of the injection zone. Carbon dioxide also has the potential to be corrosive when mixed with water.

Id. at 1. Statements like this should not be included in Guidance Documents intended for owners/operators. The inclusion of such statements implies that EPA believes that entities inexperienced with injecting CO_2 will seek GS permits. Given the expense and technical difficulty of injecting CO_2 into the subsurface, this presumption is unwarranted and contributes to the undermining of public confidence in CCS.

Much of this draft Guidance adds little to what is already in the Final UIC Class VI Rule. It also includes advisory statements that may delay and confuse the permitting process. For example, EPA states: "Owners or operators **may also want to consider** installation of landing nipples above the packer." *Id*. at 8 (emphasis added). A recommendation such as this will become a *de facto* requirement for permitting despite the fact it does not appear in the Final UIC Class VI Rule and without regard to whether site-specific characteristics dictated that the use of landing nipples are warranted. Again, EPA should avoid broad, sweeping advisory statements that may delay and complicate permitting without ensuring increased protection of USDW.

Similarly, the draft Guidance repeats the provision of the Final UIC Class VI Rule that the annular pressure between the tubing and the casing be maintained higher than the injection pressure. *See id.* at 27. Well pressure requirements are site specific and typically addressed well-by-well by the permit applicant and regulator. Accordingly, all statements regarding uniform compliance with minimum well pressure should be deleted from the final Guidance.

D. Project Plan Guidance (EPA 816-D-10-012)

This draft Guidance emphasizes that owner/operators of Class VI wells must develop, gain approval for, and implement five project-specific plans: i) an AOR and corrective action plan; ii) a testing and monitoring plan; iii) an injection well plugging plan; iv) a post-injection site care and site closure plan; and v) an emergency and remedial response plan. *See* Project Plan Guidance at iii. Because area permits are not allowed, owners/operators must presumably provide five such plans for each well. For a site with five injection wells and three monitoring wells, the owner/operator would have to provide 40 separate plans. This would be a recipe for ensuring that Class VI wells are never used – at least not commercially.[3]

The draft Guidance similarly envisions an iterative process to plan development. EPA provides that, before the first permit may be issued, owners/operators must prepare and submit the five plans. *See id.* at 2. This construct sounds good hypothetically, but would be impracticable from

[3] Existing injection demonstration projects, permitted under either Class I or Class V, have been allowed to include multiple wells in the same plans. If EPA's intent is not to require five separate plans for each proposed well, the Guidance should be revised to make this clear.

a commercial point of view. It could take years and substantial funds to prepare the required plans at the level of required detail in advance of a project. It would be impossible to obtain financing for the preparation of five pre-project plans when lenders and investors have no assurance that a project will at least advance along the regulatory path. Here, the regulatory path is a substantial set of obstacles, not a path forward. Moreover, the type of information that is needed for the five plans will come from the first well, but that well cannot be drilled without a permit, and to obtain the permit, the applicant must submit the plans. Again, this system would ensure that Class VI wells are never used commercially.

EPA should provide for the submission of plans based upon best-available data. If the data pass muster, a site-wide permit should be granted. As data are generated from the initial wells, plans are modified, but never reset back to square one, unless data indicate that a site cannot meet the regulations, endangering USDW.

Finally, the draft Guidance introduces and defines terms, such as "multiphase flow parameters," that are not defined in the final Class VI UIC rule. *See id.* at x. The guidance should incorporate by reference the definitions that exist in the Final UIC Class VI Rule.

THE CARBON SEQUESTRATION COUNCIL
1155 F Street, N.W., Suite 700
Washington, DC 20004-1312

May 31, 2011
Delivered via email

Ann M. Codrington, Director
Drinking Water Protection Division
Office of Ground Water and Drinking Water
1200 Pennsylvania Avenue, NW (MC-4607M)
Washington, DC 20460

Re: Comments on the Draft Class VI Well Construction Guidance

Dear Director Codrington:

The Carbon Sequestration Council is pleased to submit these comments on the Draft Underground Injection Control (UIC) Program Class VI Well Construction Guidance for Owners and Operators (March 2011). We appreciate having the opportunity to comment on this draft guidance and further appreciate the extension of the comment period to May 31, 2011 which has allowed us to review the four draft guidance documents in more detail than would otherwise have been possible.

We appreciate the effort that has gone into the preparation of this Guidance document and have noted a number of ways in which the Guidance will provide important information for Directors and permit applicants or operators. On some of these we have provided comment, but there are many other portions of the draft that we found to be well done on which we have not commented. Please note, however, that we have not been able to comment on every aspect of the proposed guidance documents and that additional issues may continue to arise as UIC program Directors and potential Class VI well applicants begin to try to implement the new rules. In addition, we stress all our comments assume that the Class VI rules and the Guidance Documents apply *solely* to Class VI wells and operations. Nothing in these comments should in any way be viewed as agreement or acquiescence that these standards or potential requirements might be appropriate for application to Class II operations for CO_2-based enhanced oil recovery (EOR).

We want you to understand that we greatly appreciate the approach that the Environmental Protection Agency (EPA) has taken to involving stakeholders in development of the geologic sequestration (GS) rule and these guidance documents. Nevertheless, the main focus of our comments will be on improving the draft (especially our attached detailed comments) and on expressing our major concerns about portions that should be revised or refocused.

One very important consideration bears emphasis because the draft well construction Guidance and the other draft documents appear to lose sight at times of the fact that – for materials of construction other than the injection tubing itself – compatibility "with fluids with which [they] might come into contact" is the important focus rather than compatibility with the carbon dioxide stream. Only the injection tubing will come into direct contact with the carbon dioxide stream before it mixes with other fluids. For everything else, compatibility is always to be assessed in accordance with the requirement in 146.86(b)(1) that [a]ll well materials must be compatible with fluids with which the materials may be expected to come into contact . . . ." We have suggested a number of places where this consideration can be more effectively reflected.

We have three concerns about the way long string casing is addressed in the draft Guidance. First, we agree with the American Petroleum Institute (API) which has noted that the draft Guidance does not acknowledge the important role that can be played by liners in well construction. Liners provide a very safe and effective method to ensure that the injectate is confined within the wellbore and the designated injection zone. The Guidance should recognize that liners can be used to extend the long string casing to the injection zone. Second, we agree with the API recommendation for revision of the Guidance on the requirement for the long-string casing to be cemented to surface. Staging cement jobs to step the level of the cement to the surface with two or more jobs is common practice when it is known or suspected that it will be difficult or impossible to circulate cement to surface in one attempt. Multiple staging jobs to position cement behind the long-string can be planned when/where necessary but success is never guaranteed. Subsequent perforating and cement-squeeze jobs can also be used to attempt to circulate cement to surface but again, there are no guarantees. Therefore, "if possible" should be added to the requirement. Third, we continue to support the much better alternative wording for the long string casing requirement presented by the Multi-Stakeholder Discussion participants in the MSD Recommendation letter of May 14, 2009 (copy attached).

With respect to the injection pressure limitation, we continue to believe that limiting injection pressure to ninety percent of injection zone fracture pressure is misguided and should be modified to adopt the recommendation of the Multi-Stakeholder Discussion participants. The MSD participants expressed concern about three aspects of section 146.88(a). First, it "restricts" fractures in the injection zone "except during stimulation" rather than focusing on maintaining the integrity of the confining zone, which is what really matters for protecting USDWs. Second, it fails to refer specifically to the full range of potential geomechanical failure modes potentially posed by operations at a particular site. Third, the type of geomechanical risk that is addressed (initiation or propagation of fractures), is dealt with in a potentially arbitrary fashion (the 90% of fracture pressure limit), which may not be appropriate in all cases.

The MSD recommendation addressed these concerns by focusing on maintaining the integrity of the confining zone and including tensile failure and shear failure as transmissivity concerns. It called for additional geomechanical studies of tensile failure and shear failure only "where appropriate" because there will be locations where experience or existing information will provide sufficient evidence to avoid the need for additional studies. The need for conducting additional tests and for determining which tests would be acceptable is left to the Director's discretion. Here is the recommended revision to section 146.88(a):

> The owner or operator must comply with a maximum injection pressure limit approved by the Director and specified in the permit. In approving a maximum injection pressure limit, the Director shall consider the results of well tests and, where appropriate, geomechanical or other studies that assess the risks of tensile failure and shear failure. The Director shall approve limits that, with a reasonable degree of certainty, will avoid initiation or propagation of fractures in the confining zone or cause otherwise non-transmissive faults transecting the confining zone to become transmissive. In no case may injection pressure cause movement of injection or formation fluids in a manner prohibited by 40 CFR Part 144.12(a).

We also agree with API that "[t]he regulatory requirement for an operator to maintain a pressure in the annulus greater than the operating injection pressure (page 28) is unnecessary and could be harmful to the integrity of the wellbore and the confining or injection formation." This is another point on which MSD participants were able to achieve consensus as reflected in the May 15, 2009 MSD Recommendations (copy attached). Although the final rule provides the Director discretion to adjust this requirement if maintaining an annulus pressure higher than the injection pressure may cause damage to the well or the formation, it would be better if this flexibility is explicitly acknowledged, and its application explained in the final Guidance.

In the attached Comments of the Carbon Sequestration Council on the Draft Class VI Well Construction Guidance, we provide more detailed comments and recommendations for revision of the draft Guidance consistent with our concerns.

Thank you for the opportunity to comment on the draft Draft Area of Review and Corrective Action Guidance. If you have any questions or need any additional information about these comments, please contact Bob Van Voorhees at [redacted]

Respectfully submitted,

Robert F. Van Voorhees

Robert F. Van Voorhees, Manager
Carbon Sequestration Council

cc: Bruce Kobelski, UIC Program, Drinking Water Protection Division
GSRuleGuidanceComments@epa.gov

Carbon Sequestration Council Comments on the Draft Well Construction Guidance

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6	The surface casing is the largest in diameter and typically extends from the ground surface through the base of the lowermost USDW.	146.86(b) (2) Surface casing must extend through the base of the lowermost USDW and be cemented to the surface through the use of a single or multiple strings of casing and cement.	Surface casing typically extends from the ground surface through the base of the lowermost USDW	The wording of this statement should be revised to eliminate the reference to "largest in diameter" as that could be conductor casing rather than surface casing. In addition, the use of "the" with surface casing suggests a single string when the regulation allows the use of multiple strings to for the surface casing.
6	If the well is very deep, there may be one or more intermediate casings of intermediate diameter between the surface casing and the long string casing. These casings would be cemented in place as well [§146.86(b)(3)].	146.86(b) (2) Surface casing must extend through the base of the lowermost USDW and be cemented to the surface through the use of a single or multiple strings of casing and cement.		The Guidance should be revised to recognize that one or more strings of intermediate casings may also be included in surface casing and cement strings.
6	The construction materials selected for the casing and the casing design must be appropriate for the fluids and stresses encountered at the site-specific down-hole		The construction materials selected for the casing and the casing design must be appropriate for the fluids and stresses encountered in the site-specific down-hole	Generally a good statement, but the use of "in" rather than "at" would be clearer.

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	environment [§146.86(b)(1)].		environment [§146.86(b)(1)].	
6	[T]he casing must be made out of a material that is compatible with fluids with which it might come into contact [40 CFR §146.86(b)(1)].	All well materials must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director.		This is a very important consideration and bears emphasis because the other Guidance documents appear to lose sight at times of the fact that compatibility "with fluids with which it might come into contact" is more important for the materials of construction than compatibility with the carbon dioxide stream.
6	These annuli are required to be filled with cement in Class VI injection wells, along both the surface and the long string casing [§§146.86(b((2) and 146.86(b)(3)].	146.86(b) (2) Surface casing must extend through the base of the lowermost USDW and be cemented to the surface through the use of a single or multiple strings of casing and cement. (3) At least one long string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages.	These annuli are typically filled with cement in along both surface and long string casing.	This statement is not strictly accurate in light of the actual requirements of §§146.86(b((2) and 146.86(b)(3). Because it is not necessary in the context of this statement to present the regulatory requirement, we recommend the revised language provided in the column to the left. Stating accurately the requirements that relate to cement in the annuli would require much greater explanation.
6	The smallest diameter casing	146.86(3) At least one long		The EPA GS rule does not

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	extends into the injection zone and is referred to as the long string casing. . . . The GS Rule requires the long string casing extend from the ground surface all the way down to the injection zone [40 CFR §146.86(b)(3)].	string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages.		address the use of liners, which have been proven to be safe and effective. Liners installed on the bottom of the well and across the injection zones are common and are very effective for downhole controlled dispersion of designated injectate. It is very common to install a liner on the bottom of the well if the wellbore construction and wellbore integrity are sufficient without adding another complete string of casing from the surface and through the injection zone. When a liner is lowered to the bottom of the wellbore, it is securely placed above the bottom of the casing and cemented behind the liner. This very safe and effective method can ensure that the injectate is confined within the wellbore and the designated injection zone. Wording allowing the use of liners should be added to the Guidance to clarify that the

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				requirement for long string casing to extend "to the injection zone" should not be read to preclude the use of liners. If a long string were to fall short of the storage formation by ten feet, it might not be possible to add another long string, and the well would have to be abandoned if liners were not allowed. A third string is not always possible technically and commercially.
9	The GS Rule requires that the well must be constructed to withstand anticipated stresses, last the lifetime of the project, and be compatible with the carbon dioxide stream or subsurface reaction products [§146.86(b)(1)].	146.86(b) (1) Casing and cement or other materials used in the construction of each Class VI well must have sufficient structural strength and be designed for the life of the geologic sequestration project. All well materials must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM	The GS Rule requires that the well must be constructed to withstand anticipated stresses, last the lifetime of the project, and be compatible with fluids with which the materials may be expected to come into contact [§146.86(b)(1)].	The statement in the Guidance does not accurately state the requirement of the regulation. If it is presented as a restatement of the rule, it must be accurate. If some other point is to be made, such as what may have contributed to the composition of the fluids with which the materials may be expected to come into contact, then that point should be made without attempting to present it as what the rule "requires".

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		International, or comparable standards acceptable to the Director. . . .		
12	In addition to being designed to withstand stresses, well materials must also be able to withstand corrosive forces [§§146.86(b)(1) and 146.86(c)(1)].		In addition to being designed to withstand stresses, well materials should also be able to withstand the corrosive forces inherent in any fluids with which the materials may be expected to come into contact [§§146.86(b)(1) and 146.86(c)(1)].	This should not be presented as if it is a restatement of a regulatory requirement because it is not an accurate reflection of the rule. It would be more accurate to state that well materials should be compatible with corrosive fluids if they are expected to come into contact with corrosive fluids.
12	When carbon dioxide combines with water, carbonic acid is formed. Carbonic acid is corrosive to steel and other metals. It can react with cement and alter the C-S-H and calcium hydroxide material found in typical Portland cements.			The Guidance should go further to note that, in the well bore, brine (which will presumably be alkaline) will be present rather than water. So, if acid is created, that will probably result in an reaction with the alkaline brine which might result in a decrease of acidity.
13	If the water content of the injectate stream is higher than 50 ppm, then corrosion-resistant materials are suggested on all components of the injection well that would come into contact with the carbon dioxide			We have a concern about this limit, as it seems arbitrary. Corrosion as a result of water presence will be a well-specific issue, because it takes a certain amount of time for CO2 and water to create carbonic acid (and thus the corrosion risk).

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	stream.			Thus, if the combined injection stream were traveling a great distance before injection, the potential for corrosion is heightened because of the length of time available for the reaction. If the stream were traveling a short distance, a greater content of water (perhaps higher than 50ppm) could safely be tolerated without risk of corrosion. There are a number of other issues that will impact corrosion risk. The 50 ppm limit needs to be justified, and ideally the operator should propose and justify the decision they feel is best, pending approval by the Director.
14	The materials proposed to be used will be compared to the information about the corrosiveness of the injectate and its chemical composition.			'Corrosiveness' would be a subjective term. Corrosiveness in term of what (pH or anything else ?). Also if it is with respect to a material?
14	The GS Rule requires that the surface casing must extend through the base of the lowermost USDW and be	146.86(b) (2) Surface casing must extend through the base of the lowermost USDW and be cemented to the surface	The GS Rule requires that [] surface casing must extend through the base of the lowermost USDW and be	Dropping the use of "the" in front of "surface casing" will help to avoid misleading.

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	cemented to the surface through the use of single or multiple strings of casing and stages of cement [§146.86(b)(2)].	through the use of a single or multiple strings of casing and cement.	cemented to the surface through the use of single or multiple strings of casing and stages of cement [§146.86(b)(2)].	
14	A long string casing must extend to the injection zone and be cemented to the surface [§146.86(b)(3)].	146.86(3) At least one long string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages.		The requirement that the long-string extend "to" the injection zone should be clarified in the Guidance. The phrase "to the injection zone" is vague and could be perceived as just allowing penetration of the injection zone when optimization of injection might entail the long-string extending completely through the injection zone and possibly into the layer below the injection zone. Accordingly, the Guidance should clarify that this approach is permissible.
15	The GS Rule requires use of centralizers in the long string casing [§146.86(b)(3)], and in all other cementing processes, centralizers are recommended.	146.86(3) At least one long string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages.		This is well stated and carefully tracks the rule requirement, separating what is required from what is added as a recommendation.

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20	As with other well components, the cement and any additives to the cement must be compatible with the carbon dioxide stream [§146.86(b)(5)].	(5) Cement and cement additives must be compatible with the carbon dioxide stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project.	As with other well components, the cement and any additives to the cement must be compatible with the carbon dioxide stream and formation fluids [§146.86(b)(5)].	The statement as presented is not accurate because overall compatibility is always to be assess by the requirement in 146.86(b)(1) that [a]ll well materials must be compatible with fluids with which the materials may be expected to come into contact . . . . By stating that cement and cement additives "must be compatible with the carbon dioxide stream and formation fluids", subsection (b)(5) is simply seeking to reflect that requirement, not impose a new requirement. In any event, the restatement of the requirement should not be truncated as it currently is.
20	In addition, higher temperatures experienced in down-hole environments can also increase the rates of alteration of Portland cement (Barlet-Gouedard et al., 2006, Kutchko et al., 2008, Duguid and Scherer, 2009).			The referenced work by Duguid and Scherer (2009) may not be completely representative of real wellbore situation. The Guidance should also cite other studies showing that Portland cement in a 55 year old well with 30 years of CO2 exposure retained its capacity to prevent significant

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				fluid transport. "Analysis and performance of oil well cement with 30 years of CO2 exposure from the SACROC Unit, West Texas, USA, J.William Carey et al., 2007, International Journal of Greenhouse Gas Control".
22	Most well logs used to measure the quality of the cement bond perform best when run directly against the casing. Therefore, to obtain the best measurement of the quality of the cement bond through the confining layer as possible, EPA recommends placing the packer near the top of the confining layer to obtain the best results.		Well logging of the confining zone can be affected by packer placement. Therefore, to obtain the best measurement of the quality of the cement through the confining layer as possible, while not creating unnecessary risks, EPA recommends placing the packer near the top of the confining layer to obtain the best results, recognizing that this approach may need to be modified based on well-specific issues so as to maximize measurement quality while not creating additional risks to well integrity or downhole equipment.	Many cement logs do not need to run directly against the casing to measure the integrity of the cell, although some do. Additionally, packer placement can impact the ability to test wellbore integrity, the mechanical stress on well components during operation, and the risks to tools and equipment during well intervention. Accordingly, we agree with the recommended revision submitted by the American Petroleum Institute (API).
22-23	The owner or operator must submit the following	(3) In order for the Director to determine and specify		This discussion in part 2.7 of the Guidance seems a little

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	information to the UIC Program Director at the time of the permit application [§146.86(c)(3)(i)-(vii)]:	requirements for tubing and packer, the owner or operator must submit the following information: (i) Depth of setting; (ii) Characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids; (iii) Maximum proposed injection pressure; (iv) Maximum proposed annular pressure; (v) Proposed injection rate (intermittent or continuous) and volume and/or mass of the carbon dioxide stream; (vi) Size of tubing and casing; and (vii) Tubing tensile, burst, and collapse strengths.		disjointed and becomes confusing. The initial statement quoted in the first column to the left appears to relate broadly to well construction, but the provision cited and paraphrased relates only to tubing and packer materials and placement. Then, the paragraph following the listing of the information also appears to relate to tubing and packer until it gets to the last sentence. That sentence, after an introductory reference to tubing and packer, unexpectedly shifts to discussing what appears to be placement of the well itself rather than the packer: "the UIC Program Director will either approve the proposed Class VI injection well location or require a different location to be characterized and proposed as a GS project site." This does not make sense and should be revised. To close out the thought more appropriately, the sentence should end by discussing packer depth

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				placement.
23	Ideally the packer will be placed with the confining layer.		Generally, the packer should be placed near the top of the confining layer, recognizing that this approach may need to be modified based on well-specific issues so as to maximize measurement quality while not creating additional risks to well integrity or downhole equipment.	Well logging of the confining zone can be affected by packer placement. Therefore, to obtain the best measurement of the quality of the cement through the confining layer as possible, while not creating unnecessary risks, EPA could recommend placing the packer near the top of the confining layer to obtain the best results, recognizing that this approach may need to be modified based on well-specific issues so as to maximize measurement quality while not creating additional risks to well integrity or downhole equipment. In every case, the operator should have the option to set the packer optimally with respect to well and local conditions. For example, if there is a very thick injection zone (hundreds of feet), the GS project could first inject into a lower portion of that zone. In that case, there may be a technical advantage to

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				setting the packer deeper, rather than several hundred feet high to have it across the confining zone. It is difficult to foresee all the possible variables and possibilities, so flexibility in where the packer goes in order to allow adaptation to the site specific conditions will be an advantage for everyone.
23	If any of the above information changes due to additional information gained during the drilling of the well and the subsequent required logging and data analysis before operation commences, the revised information about the tubing and packer materials to be used in Class VI injection well construction must be submitted to the UIC Program Director prior to operation of the injection well [§146.82(c)(5)].	146.82(c) Prior to granting approval for the operation of a Class VI well, the Director shall consider the following information: * * * (5) Final injection well construction procedures that meet the requirements of §146.86;	If any of the [] information used by the Director to determine and specify requirements for tubing and packer changes [] during the drilling and construction of the well[], the revised information [] must be submitted to the UIC Program Director prior to operation of the injection well [§146.82(c)(5)].	This statement is not supportable by reference to §146.82(c)(5). The statement appears to use an amalgam of provisions in 146.82(c), not all of which have any bearing on tubing and packer specifications. The proposed revision is simpler and consistent with the need to review actual construction procedures and specifications to be sure that determinations about tubing and packer are still appropriate.
25	The owner or operator must report the type and location of the safety valve(s) and any landing nipples as part	146.82(a) Prior to the issuance of a permit for the construction of a new Class VI well or the conversion of	The owner or operator must submit schematics or other appropriate drawings of the surface and subsurface	The statement as it currently appears in the Guidance is not an accurate restatement of the rule requirements. It should be

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	of the construction plans and procedures submitted with the permit application [§§146.82(a)(11) and 146.82(a)(12)].	an existing Class I, Class II, or Class V well to a Class VI well, the owner or operator shall submit, pursuant to § 146.91(e), and the Director shall consider the following: * * * (11) Schematics or other appropriate drawings of the surface and subsurface construction details of the well; (12) Injection well construction procedures that meet the requirements of § 146.86;	construction details of the well [§§146.82(a)(11)], which should include the type and location of safety valve(s) and any landing nipples.	revised to make the proper distinction between what is required and what is offered as guidance.
26	The GS Rule requires that the injection pressure may not exceed 90 percent of the injection zone fracture pressure except during stimulation [§146.88(a)].	146.88(a) Except during stimulation, the owner or operator must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure initiate fractures in the confining zone(s) or cause	We are concerned about three aspects of proposed section 146.88(a), governing injection pressure limitations. First, it "restricts" fractures in the injection zone "except during stimulation" rather than focusing on maintaining the integrity of the confining zone, which is what really matters for protecting USDWs. Second, it fails to refer specifically to the full	We continue to believe that this limitation on injection pressure is misguided and should be modified to adopt the recommendation of the Multi-Stakeholder Discussion participants (repeated in the column to the left).

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		the movement of injection or formation fluids that endangers a USDW. Pursuant to requirements at § 146.82(a)(9), all stimulation programs must be approved by the Director as part of the permit application and incorporated into the permit.	range of potential geomechanical failure modes potentially posed by operations at a particular site. Third, the type of geomechanical risk that is addressed (initiation or propagation of fractures), is dealt with in a potentially arbitrary fashion (the 90% of fracture pressure limit), which may not be appropriate in all cases. Our recommended language addresses these concerns by focusing on maintaining the integrity of the confining zone and including tensile failure and shear failure as transmissivity concerns. It calls for additional geomechanical studies of tensile failure and shear failure only "where appropriate" because there will be locations where experience or existing information will provide sufficient evidence to avoid	

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			the need for additional studies. The need for conducting additional tests and for determining which tests would be acceptable is left to the Director's discretion. The owner or operator must comply with a maximum injection pressure limit approved by the Director and specified in the permit. In approving a maximum injection pressure limit, the Director shall consider the results of well tests and, where appropriate, geomechanical or other studies that assess the risks of tensile failure and shear failure. The Director shall approve limits that, with a reasonable degree of certainty, will avoid initiation or propagation of fractures in the confining zone or cause otherwise non-transmissive faults transecting the confining	

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			zone to become transmissive. In no case may injection pressure cause movement of injection or formation fluids in a manner prohibited by 40 CFR Part 144.12(a).	
26	Maintaining the injection pressure below 90 percent of the injection zone fracture pressure prevents the injection from fracturing the confining layer and allowing fluids to leak out of the injection zone.			This statement might not be valid always, because the overlying layers can have a higher fracture pressure than the injection horizon.
26	If stimulation is to be performed, other than the formation testing conducted under §146.82, the UIC Program Director must be notified at least 30 days before the operation is performed [§146.91(d)(2)]. In either case, the proposed stimulation method must demonstrate that it will not fracture the confining zone or otherwise allow injection or formation fluids to endanger USDWs [§146.88(a)].	146.88(a) * * * In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW.		This can be done by modeling pressures and showing that the fracture pressure of the confining zone is not exceeded. The limitation that caprock will never be able to be fractured is excessive as a categorical statement. Sites with very thick caprock intervals should be permitted some latitude to have a fracture extend into the caprock by some percentage.

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26	The modeled pressures can be confirmed using sensors such as tiltmeters and microseismic monitoring to monitor and refine the model; however, these technologies are still experimental.			Microseismic monitoring techniques might not be applicable everywhere.
27	The installation and use of continuous recording devices to monitor various pressure and volumes, as well as injection rates is also required [§146.88(e)(1)].			The Guidance should provide a clear indication that digital recording devices are considered to meet the requirement to be "continuous" even thought they capture information on an interrupted basis.
28	The surface casing must extend through the base of the lowermost USDW and be cemented to the surface [§146.86(b)(2)].	146.86(b) (2) Surface casing must extend through the base of the lowermost USDW and be cemented to the surface through the use of a single or multiple strings of casing and cement.	Surface casing must extend through the base of the lowermost USDW and be cemented to the surface through the use of a single or multiple strings of casing and cement. [§146.86(b)(2)]. Dropping the use of "the" in front of "surface casing" will help to avoid misleading.	The following more correct statement appears on page 14 of the draft Guidance: "The GS Rule requires that the surface casing must extend through the base of the lowermost USDW and be cemented to the surface through the use of single or multiple strings of casing and stages of cement [§146.86(b)(2)]."
28	The surface casing must extend through the base of the lowermost USDW and be	146.86(b) (4) Circulation of cement may be accomplished by staging.		Consistent with the provisions of section 146.86(b)(4), we agree with the API

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	cemented to the surface [§146.86(b)(2)].	The Director may approve an alternative method of cementing in cases where the cement cannot be recirculated to the surface, provided the owner or operator can demonstrate by using logs that the cement does not allow fluid movement behind the well bore.		recommendation that: EPA should not require surface casing to be cemented to surface in every case. EPA should amend the Guidance to provide for top-off. If cement does not reach the surface or falls back when the pump stops, it's common to pump cement down from the surface and into the outside of the surface casing with a 1" pipe. This is commonly referred to as "1 inch or top-off with 1 inch". It is a very common practice because the cement level often falls due to its weight as the cement fills voids in the wellbore on the outside of the casing. The process is common and EPA should refer to the process in the Guidance.
28	The long-string casing extends to the injection zone and must also be cemented to the surface [§146.86(b)(3)].	146.86(3) At least one long string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages.	As noted by API in the comments reproduced in the column to the right, this requirement is problematic. We also reiterate the comments on this issue and the recommendation of the Multi-Stakeholder	We agree with the API recommendation for revision of the Guidance on this issue: The requirement for the *long-string* to be cemented to surface in every situation should be modified. Consistent with Section 2.5.1 of the Guidance

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			Discussion participants: EPA's proposed §146.86(b)(3) would require the long string casing to be cemented by circulating cement to surface in one or more stages. Yet that may be hard to accomplish in some cases, such as very deep wells. There are also potential disadvantages of this approach with regard to the weight of the cement column and its relation to well integrity. Sealing this annulus also eliminates an approach for monitoring the integrity of the cement in that critical interval through the primary confining interval and above. We recommend that EPA not make this a mandatory requirement. The requirement should also recognize that there may be other technologies that could be as effective as cement and centralizers, which may not be feasible in some applications; furthermore, current research	allowing alternatives if cementing to the surface cannot be done, the statement on page 28 should read "long-string should be cemented to the surface if possible". The issue is that it isn't always possible to circulate cement to surface for various reasons. Staging cement jobs to step the level of the cement to the surface with two or more jobs is common practice when it is known or suspected that it will be difficult or impossible to circulate cement to surface in one attempt. Multiple staging jobs to position cement behind the long-string can be planned when/where necessary but success is never guaranteed. Subsequent perforating and cement-squeeze jobs can also be used to attempt to circulate cement to surface but again, there are no guarantees. Therefore, "if possible" should be added to the requirement.

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			and development efforts are likely to yield additional technologies the use of which should not be foreclosed. Accordingly, we recommend the following language for §146.86(b)(3): "(3) At least one long string casing, using a sufficient number of centralizers, which at a minimum: must be sealed from within the injection zone upward through the overlying confining zone, and must provide adequate isolation of the injection zone and other intervals as necessary for protection of USDWs using cement and/or other isolation techniques. The Director may approve the use of packers or alternative isolation techniques, provided these are demonstrated to be equivalent to cement or more effective to provide adequate isolation and to protect USDWs." MSD Letter of May 14, 2009 at 5.	
27	The GS Rule requires that annular pressure between the	146.88(c) The owner or operator must fill the annulus	We also reiterate our view that the wording of the final	We support the comments of API regarding the regulatory

Page	Guidance Statement	Final Rule Provisions	Recommended Revisions	Discussion
	tubing and the casing be maintained higher than the injection pressure and that the annulus be filled with a non-corrosive fluid [§146.88(c)].	between the tubing and the long string casing with a non-corrosive fluid approved by the Director. The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs.	rule is itself problematic. That is why the Multi-Stakeholder Discussion participants made the following recommendation: Agency and industry experience with the Class II UIC program does not support a requirement to "maintain on the annulus a pressure that exceeds the operating injection pressure." The standard proposed by EPA is consistent with neither the risk level related to CO_2 nor the specifications needed to monitor the annular space for leakage. We suggest revising section 146.88(c) to read: "(c) The owner or operator must fill the annulus between the tubing and the long string casing with a corrosion inhibiting fluid approved by the Director. The owner or operator must maintain a positive pressure on the annulus."	requirement for an operator to maintain a pressure in the annulus greater than the operating injection pressure, which is unnecessary and could be harmful to the integrity of the wellbore and the confining or injection formation. EPA acknowledges that, in some circumstances, maintaining an annulus pressure greater than the injection pressure could result in a greater chance for damage to the well or the formation. As a result, the final rule provides the Director discretion to adjust this requirement if maintaining an annulus pressure higher than the injection pressure may cause damage to the well or the formation. However, it would be better if this flexibility was explicitly approved in the guidance document. EPA's reasoning assumes that the failure will occur in the long string tubing and when/if it occurs, the CO2 will be forced
28	This annular space must be filled with a non-corrosive fluid approved by the UIC Program Director and the owner or operator must maintain a pressure on the annulus greater than the operating injection pressure, unless the UIC Program Director determines that such pressure requirements could harm the integrity of the well or endanger USDWs [§146.88(c)].			

Page	Guidance Statement	Final Rule Provisions	Recommended Revisions	Discussion
				to stay in the tubing if the tubing-casing annulus pressure has a greater pressure. This could occur, however all possible failure modes of the well must be examined and their effect. In a tubing leak, once the tubing-casing annulus and tubing pressures equalize, the CO_2 could easily flow into the annulus anyway. Likewise, if the packer fails, the packer fluid in the tubing-casing annulus will flow downward and into the formation. The CO_2 in the wellbore would replace the packer fluid when it leaves the annulus. The nature of CO_2 itself requires that the surface pressure be high to keep the CO_2 supercritical and avoid phase changes in the tubing. This is different than injecting a dense fluid and the EPA requirement means an operator needs to have a pressure on the annulus at the top of the well that is significantly over

Page	Guidance Statement	Final Rule Provisions	Recommended Revisions	Discussion
				formation fracture pressure and likely to be over the formation fracture pressure for the entire length of the well. The result of a casing leak with an annulus pressurized to this degree would be an uncontrolled fracture of the surrounding formation and injection of the packer fluid into the formation. As the packer fluid is likely to be a stabilized brine, this could lead to a brine injection into a USDW. Furthermore, applied casing pressure creates ballooning and will result in additional stress cycles on the cement sheath over the life of well. Stress cycles – due to periodically adding pressure over time - may debond the cement interfaces and induce fractures in the matrix. Wellhead injection pressure is likely to be at least 1200 psi for a CO_2 injector which could require approximately 1500 psi applied casing annulus pressure. Jackson, et al, 1996, indicate a

Page	Guidance Statement	Final Rule Provisions	Recommended Revisions	Discussion
				change in diameter of 0.003 inches is sufficient to create a microannulus leakage pathway. Applied casing pressure of 1500 psi with a packer fluid of 8.6 ppg density in a 7", 26 ppf casing may create up to 0.0034 inches based on API 10TR, Cement Sheath Evaluation, 2007, assuming normal pore pressure conditions. This means that operating with a higher pressure on the annulus and the ballooning effect associated with periodically adding pressure may over time reduce the cement bonding between the long-string and the cement behind the long string.
28	The owner or operator must also maintain the mechanical integrity of the well at all times [§146.88(d)].	146.88 (d) Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the owner or operator must maintain mechanical integrity of the injection well at all times.		Although the intent is to ensure that the operator is prudent with injection operations, it is possible a component will fail over the multi-decade life of a well and the operator should be charged with proactive failure identification and resolution. The Guidance should make clear that operator is tasked with putting a program in place

Page	Guidance Statement	Final Rule Provisions	Recommended Revisions	Discussion
				to monitor injection operations, to respond immediately when a failure is discovered, to repair the failure and to regain any lost mechanical integrity. No operator can maintain mechanical integrity of a well at all times. All operators should ensure that a plan is in-place to minimize failures and to respond immediately when and if a failure does occur.

AMERICAN ELECTRIC POWER

American Electric Power
400 West 15th Street, Suite 1500
Austin, TX 78701
aep.com

May 31, 2011

VIA EMAIL: GSRuleGuidanceComments@epa.gov

Ann M. Codrington, Director
Drinking Water Protection Division
Office of Ground Water and Drinking Water
1200 Pennsylvania Avenue, NW (MC-4607M)
Washington, DC 20460

RE: Comments of American Electric Power to the following Guidance Documents issued by the Environmental Protection Agency's (EPA) Drinking Water Protection Division in March 2011:

Draft Underground Injection Control (UIC) Program Class VI Well Site Characterization Guidance for Owners and Operators

Draft Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance for Owners and Operators

Draft Underground Injection Control (UIC) Program Class VI Well Construction Guidance for Owners and Operators

Draft Underground Injection Control (UIC) Program Class VI Well Project Plan Development Guidance for Owners and Operators

Dear Director Codrington:

American Electric Power appreciates this opportunity to provide comments to four guidance documents issued by the Drinking Water Protection Division in March 2011 for the stated purpose of providing "information and recommendations that may be helpful for UIC Class VI program implementation efforts. " (Page i, of each guidance document.) AEP appreciates the approach and efforts EPA has undertaken in engaging and meeting with the stakeholders, in not only the Class VI rulemaking process but also in the development of the guidance documents to date.

As you know AEP, along with its strategic partners, is a leader in the development of technology to sequester CO2 from flue gas emissions and inject the resulting CO2 supercritical gas into a subsurface formation for long term storage. AEP's pilot project for this technology is located at AEP's Mountaineer Plant in New Haven, West Virginia. AEP is in a unique position with its developing expertise to provide comments on these guidance documents and the earlier guidance document on financial responsibility. AEP hopes to continue the same constructive dialogue with EPA as future guidance documents are developed and issued.

In the comment letter at hand, AEP will provide **General Comments** that apply to all four proposed guidance documents first, followed by **Specific Comments** to each of the four guidance documents.

I. General Comments

AEP recommends that EPA closely follow the requirements that are specified in the Class VI rule. The CCS projects and rule implementation are in their infancy and AEP understands that the intent of EPA is for the well development and regulatory process to be iterative. Therefore, EPA should resist providing recommendations beyond what the Class VI rule requires in the guidance documents. AEP is fearful that these recommendations could be viewed as requirements by the state authorities seeking primacy of the Class VI program. AEP understands that the Class VI Rule was designed to be protective of USDWs. Therefore, EPA should not add what could be seen as additional requirements beyond what is already considered protective.

AEP requests that EPA allow comments to be submitted on previous guidance documents as subsequent guidance is issued and considered. AEP anticipates that subsequent guidance may influence comments that were made on previously proposed guidance documents as those documents are issued and can be read in relation to each other. Growing experience by the regulated industry with the technology and use of the Class VI Rule and guidance will also be fruit for comments. EPA's maintaining a conversational approach will improve the workability and usefulness of the guidance documents.

AEP recommends that EPA consider an approach to consolidate permits for individual wells permitted within the same storage facility. A well by well approval process may lead to costly and duplicative efforts for no apparent benefit for wells within a similar geologic structure and formation. EPA should consider guidance for an approval process for "area wells."

AEP supports the comments submitted to EPA on these guidance documents by the Edison Electric Institute and the Carbon Sequestration Council.

II. Specific Comments

Draft Underground Injection Control (UIC) Program Class VI Well Site Characterization Guidance for Owners and Operators (Site Characterization Guidance)

In general, the Site Characterization Guidance contains what appears to be superfluous information on geology, geophysics and formation chemistry with little constructive direction for an owner, operator or regulatory agency to use in different geologic settings in determining what should be included in a permit application. AEP recommends that EPA consider its audience, simplify its guidance and consider removing the definitions that are tied to information that is not contained in the regulations and is neither pertinent nor helpful in developing permit application submittals. The voluminous information that EPA recommends collecting seems to go beyond the scope of the Class

VI rule and could prove unwieldy and costly to an applicant and regulatory agency. AEP understands that the guidance as EPA states on Page 5 is meant to provide assistance for ***initial*** characterization. For example, the rule requires that maps and cross-sections be provided to ***illustrate*** regional geology (§146.82(a)(3)(vi)) and ***baseline*** geochemical data on subsurface formations in the area of review. However, the guidance could lead one to believe much more than an illustration, baseline or demonstration of general conditions is expected by the Class VI rule. A regulatory agency should have discretion depending on the characteristics of the AoR to determine what information is necessary.

As another example of a recommendation that goes beyond what is required by the Class VI rule, in Section 2.2, Page 11, 4th bullet, EPA recommends that permit applications contain all USDWs in the Area of Review and the region and a statement of whether USDWs are currently being used for drinking water. Additionally, Region is not a defined term or used in the Class VI Rule and I assume a drinking well's relevance will depend on the Area of Review (AoR), not the Region. Regulatory agencies should be allowed some discretion in determining what wells are relevant to the evaluation of the AoR.

More specifically, on Page xv, Definitions, the Guidance provides a definition for transmissibility but does not provide a definition for permeability, which is used extensively in the Guidance. (The Guidance does define effective permeability, intrinsic permeability and relative permeability.) Because the Guidance uses the expression "vertical permeability (or transmissibility)" on page 92, it would be helpful to provide an explanation of the relationship between transmissibility and permeability, perhaps in the definition of transmissibility. Note that there is a statement on page 39 that "Permeability is the ability of a material to transmit fluids."

Draft Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance for Owners and Operators

Generally. AEP recommends that EPA resist turning the Area of Review evaluation into a data gathering study. The comments below illustrate the complexity of the techniques EPA discusses and the fact that utilizing the evaluation techniques is a complex, time consuming, difficult and costly task that may or may not add any additional knowledge into evaluating the AoR for the permitting process.

Specific Comments:

Page 9, first paragraph, last 2 sentence: These two sentences seem confusing. One will NEED a reactive transport model to know IF there might be precipitation and hence a change in porosity and permeability. Similarly, the same holds true with the geomechanical model.

It should also be noted that incorporating all three models together is not a trivial issue and hence that effort will be time intensive.

Page 10, first paragraph, last sentence: It should be noted that the simulation of flow through a fractured reservoir is different than flow through a non-fractured reservoir. AEP recommends that EPA include a statement which recognizes that the same simulation codes might not be able to be used for both a fractured and non-fractured reservoir. In addition, modeling individual fractures will require too may grid elements; and, therefore this type modeling may be rendered un-realistic in practice.

Page 16, first paragraph, last sentence: There are two sets of results that appear contradictory.

Page 17: AEP recommends that EPA note and include a statement which recognizes that in general, literature studies suggest that the time period for mineral precipitation reactions is on the order of hundreds years.

Page 23, second paragraph: AEP recommends that EPA recognize that the problems that were studied are clearly for the 'idealized' situation and may not be appropriate for guidance. For a reservoir simulation, the input 'static' model is probably the most important parameter. Most geological interpretations will have inherent uncertainty and hence will have a much larger impact in the simulation results than effects on incorrect fluid properties.

Page 28, figure 3.1: AEP questions the use of the figure for illustration purposes when it shows the direction of the ground water flow up-dip.

Page 40, first paragraph, second sentence : 'Artificial penetration' needs to be specified clearly or defined. It is unclear if any well or only deep wells that go up to the target reservoir can be considered a potential problem. Moreover, other than deep wells it is difficult to envision any other deep "artificial" feature.

Page 40, section 4.1: It is unclear why EPA has referenced abandoned mines. Assuming this is a reference to wells that were used for mining would these also need to be re-mediated ?

Page 41, second paragraph: In order to detect each of these specific problems, each well has to be reviewed in detail. This is another example where the effort to gather information for evaluation in areas with substantial number of drilled wells, will be time intensive and expensive and may or may not result in useful information for evaluating an AoR.

Page 47, Ground Penetrating Radar (GPR): In regions where the topography changes appreciably, application of GPR might be questionable. Also, the presence of subsurface pipelines will complicate GRP measurements. This technique may not be useful in certain situations.

Page 48, second paragraph, last sentence and Page 53, section 4.31: If well integrity, cement or casing information for a previously drilled well is not available, a permittee should have the option to test, plug or work with the permitting agency to address an unknown well that is within the AoR evaluation using the suggested techniques.

Figure 5-1, Page 61: A scale for length is necessary for this plot. Having a large number of deep monitoring wells is very unrealistic for an industrial scale sequestration project. Each monitoring well is a potential pathway for leakage. Obviously the need for monitoring should be weighed against the risk of leakage.

Figure 5-2: Matching the pressure response of a large number of monitoring wells with the reservoir simulation will be a complicated and time consuming undertaking. Moreover, the degree of the match would probably vary over the area of study.

Page 66, Figure 5.6: The numerical model illustrated in Figure 5.6 might not be applicable at all sites, especially at a commercial scale facility. Crosswell seismic testing requires that wells be in close proximity. Wells cannot be more than approximately 2000 feet apart for reasonable detection.

Page 67, second paragraph: Monitoring at every monitoring well for the purposes of this paragraph is impractical. Moreover, the fluid properties will change only when there will be a CO2 breakthrough. EPA should note that geophysical surveys have limitations.

Page 69: In some areas of the country there will be subsurface rights as well as surface rights that may be impacted if the reevaluation model differs significantly from the initial model. Are there other consequences that should be considered by EPA?

Draft Undeground Injection Control (UIC) Program Class VI Well Construction Guidance for Owners and Operators

AEP has the following specific comments to make to this technical document:

Page 12, last paragraph: In the well bore, brine (which will presumably be alkaline) will be present rather than water. So, if acid is created, it will probably be mitigated by the alkalinity of the brine, which might result in a decrease of acidity.

Page 13, second paragraph: What is the support documentation for the number reference "higher than 50 ppm?" How does EPA know that this amount of water will make the CO2 stream corrosive?

Page 14, second bullet: "Corrosiveness" could be a subjective term. Does EPA's use of this term refer to pH or corrosiveness with respect to a certain material?

Page 20, third paragraph: EPA's reference to Duguid and Scherer, 2009 is probably not very representative of a real wellbore situation. There are also studies that could be referenced which show that Portland cement in a 55 year old well with 30 years CO2 exposure retained its capacity to prevent significant fluid transport. See Analysis and Performance of Oil Well Cement with 30 Years of CO2 exposure from the SACROC Unit, West Texas, USA, J.William Carey et al., 2007, International Journal of Greenhouse Gas Control"

Page 26, third paragraph, first sentence: This statement may not be valid at all times because the overlying layers can have a higher fracture pressure than the injection horizon.
Page 26, 4th paragraph, first sentence: The microseismic technique might not be applicable everywhere.

Draft Underground Injection Control (UIC) Program Class VI Well Project Plan Development Guidance for Owners and Operators

AEP's comments to this guidance document reflect our specific experience with the Mountaineer Plant's CO2 sequestration pilot project in New Haven, West Virginia.

Mechanical Integrity is defined as "the absence of significant leakage within the injection tubing, casing, or packer… or outside of the casing." While such a definition seems instructive, use of the term, "significant" without a similar definition, can be problematic. For example, AEP recently experienced an incident at its Mountaineer AEP-2 CO2 injection well that resulted in an automatic shutdown of CO2 injection. An investigation of the system indicated no loss of mechanical integrity and injection operations resumed. However, the UIC permit required that the WVDEP be notified within 24 hours if the well appeared to be lacking mechanical integrity. Mechanical integrity is defined in the permit as "no **significant** leak in the casing, tubing or packer." The agency was not notified because, based on an interpretation of the permit and on operating experience, it was not believed that a loss of mechanical integrity had occurred. However, due to this event and on our ongoing development of this technology, AEP requested that the WVDEP confirm our interpretation and clarify how it would define a "significant" leak in the casing, tubing or packer so that, in the event of a future occurrence, the appropriate notifications could be made.

As it turns out, the agency agreed with our handling of the situation, but it never did clarify what it considered to be a "significant" leak. While AEP agrees that the release of minimal or de minimis amounts of CO2 should not be classified as significant and require agency notification, it would be helpful to agree on a definition of the term.

1.1 Overview and Need for Project Plans. For the current Mountaineer project in New Haven, WV, AEP submitted a testing and monitoring plan and a post-injection site care plan to the WVDEP. During implementation of the testing and monitoring plan, AEP encountered problems with testing procedures and technologies, which often forced a change in the monitoring schedule. Since the WV agency views these documents as "guidance," AEP has never had any compliance issues. However, according to the proposed Class VI guidance, the associated plans will now become an "enforceable" part of Class VI permits (see 1.1 Overview and Need for GS Project Plans, first paragraph, second sentence, page 1). This statement is in contradiction to the preceding introductory paragraph that states that the guidance is to "present recommendations . . . in developing project plans required . . ." in the rules. If these plans are to be as specific as those that are currently on file with the WVDEP, and AEP has no reason to believe that they wouldn't be, AEP feels quite certain that compliance problems will be encountered. The technology simply isn't "ready for prime time." In addition, if any of these plans need to be "significantly" revised, a permit modification will be required. During such a permit modification, the permit must be opened to the arduous public comment process, which may or may not go well for projects of this nature.
Based on the developmental stage of this technology, it appears that frequent permit modifications will be necessary. For example, during the construction of injection well AEP-1 at the AEP MT PVF, logging of the cement sheath surrounding the long-string casing suggested the existence of potential uncertainties in the quality and/or continuity of the cement above a certain depth. To address the issue, AEP proposed, that, in addition to the annual external mechanical integrity testing

(MIT) specified in the testing and monitoring plan (temperature log and /or radioactive tracer survey), an interim external MIT would be done within three months after the start of CO_2 injection.

The radioactive tracer (RAT) test was originally scheduled for the week of December 2009, however, due to the interruption of injection operations, the test was delayed until January 2010, during which problems were again encountered. During the first test attempt, a small quantity of tracer was leaking from the tool and smeared on the inside of the tubing. At that time, it was indicated that the tool would require repair and that injection into the well overnight would be required to flush the tracer out of the well. This was performed and a spare tool was put into service on the following day. However, the second tool also began to leak tracer material and had to be removed from the well.

After the failure of the first two tools, a third tool was used with the same tracer (I-131) and a similar injection mechanism, but with an end-check-valve addition. This check valve prevented the migration of CO_2 into the tracer reservoir at depths and a mechanism was added that contained the tracer in a glass vial. The vial was remotely broken releasing the tracer at the desired location.

Following a successful restart of the capture system, these changes allowed the successful completion of the RAT test; however, AEP could not meet the monitoring schedule described in the testing and monitoring plan. Had this plan been an enforceable part of the UIC permit, AEP would have been in violation. Had the WVDEP determined that the original permit and associated testing and monitoring plan were too restrictive, a permit modification would have been necessary to rectify the problem. However, since the WVDEP views the current testing and monitoring plan as "guidance," it was not necessary to modify the testing and monitoring plan or the UIC permit and AEP was able to complete the testing (which indicated no problems with the concrete).

Therefore, this first paragraph should be modified to reflect that certain information is required to permit a well and deviations from the plan that are based on guidance recommendations are not considered to be "violations."

1.2 Interaction of GS Project Plans. The guidance does not appear to allow the drilling of any test wells prior to the submission of the UIC permit application or any of the five project plans (See parenthetical at the top of page 3). While some preliminary information would be available, EPA recommends that the operational-phase plans (AoR and Corrective Action Plan, Testing and Monitoring Plan, and Emergency and Remedial Response Plan) be revised after the AoR modeling has been completed. This appears to be a very inefficient process. Why not allow the plans to be developed concurrently with the AoR modeling so that follow-up revisions are not necessary? It is also not realistic to assume that a valid UIC permit application could be submitted without the geological data that would be acquired from a test well.

2.1.1 The method for delineating the AoR. For the AOR and Corrective Action Plan, the permittee is required to, "predict movement of the plume and pressure front, given the particular geologic conditions at the site." (pg 10, second full paragraph) How is the permittee supposed to determine the particular conditions of the site without being allowed to drill a test well first (see above comment)?

In addition, the guidance states that, "the type and number of subsurface formations from the surface to the injection zone, as determined by borehole sampling and logging, geophysical, and others tests or methods," (top of page 11) must be included in the AoR delineation. How is this information to be obtained if the permittee is not permitted to drill a test well?

2.1.5 How corrective action will be conducted. "Guaranteeing" that surface access can be obtained to perform corrective action is not realistic, especially if the permittee does not own the wells. The permittee can provide a plan for obtaining surface access rights to perform corrective action and this should be all that is required or recommended by the guidance. The UIC rule does not require a "guarantee."

3.1.4 Under the Testing and Monitoring Plan section, the agency is recommending that a permittee "consider the installation and operation of more than a minimally acceptable number of monitoring wells." The recommended number of wells described in the preamble to the Class VI rule is already so high as to make commercial scale application of CCS economically unrealistic. The rule introduces a new, intermediate type of monitoring well, which was not required for the existing AEP Mountaineer PVF. The current project includes three deep monitoring wells and no intermediate wells for each injection well, while the new rule requires the installation of both deep and intermediate wells to monitor the CO_2 and underground sources of drinking water (USDWs). The number and location of these wells are subject to the Director's discretion, but it is safe to assume that many intermediate wells, at a cost of \$2M each, and many new deep wells, at a cost of \$6M each, will be required for a commercial scale project. It is estimated that the new requirements will have a minimum \$18M impact on the project cost estimate for each injection well, which is based on the current flexibility allowed by the WVDEP for the existing Mountaineer project. If the Director requires the maximum number of monitoring wells implied by the rule pre-amble, the cost impact could approach \$70M per injection well.

Without technical justification, agency promotion of additional monitoring wells is arbitrary and does not support the development of this technology. In fact, the installation of unnecessary deep and intermediate wells could make many CCS projects economically nonviable.

We agree with the approach taken in the following paragraph in which the agency recommends that owners/operators consider the trade-offs between an extensive monitoring program with one that is based on a site-specific approach considering subsurface geology and closely tracing the CO2 plume.

3.1.5 A demonstration of external mechanical integrity. The guidance states that external mechanical integrity tests (MITs) must be performed at least once per year. However, the permittee may, "set the testing schedule to coincide with regularly scheduled well workovers or other routine well maintenance" (page 29, last paragraph). This type of flexibility is very helpful and will allow the operators of CCS projects to accomplish the required testing in an effective and affordable manner. Many of the stipulated tests (pressure fall-off testing, etc.) require extensive preparation and it is not efficient to require injection operations to be repeatedly interrupted in order to allow the well testing to be conducted.

3.1.8 Surface air monitoring and/or soil gas monitoring. Surface and/or soil gas monitoring may be required by the agency, but must be "based on potential risks to USDWs within the AoR." (page

31, second last paragraph). The issue of surface air and/or soil gas monitoring has been addressed before and we reiterate those concerns with the following from the Carbon Sequestration Council, which was filed on December 23, 2008.

> "The goal of any UIC program regulation for GS should be to ensure that injected CO2 streams remain confined in the subsurface and do not endanger underground sources of drinking water. We are recommending sufficient requirements to ensure that this goal is achieved. As EPA seems to recognize, surface air or soil gas monitoring would impose substantial costs and the results of such monitoring would be subject to a host of confounding factors. Worst of all, such monitoring would be aimed at leakage of CO2 all the way to the surface, which – in the case of any properly-permitted GS project – would by definition be an extraordinarily low probability scenario. Accordingly, such requirements should not be imposed, nor should regulators have discretion to impose them. If there is any serious concern that injected CO2 might actually vent to the surface in a particular location, injection should not be permitted at that site in the first place. The regulations should not suggest otherwise."

AEP hopes that agency Directors use appropriate discretion and limits any application of this testing methodology.

3.1.9 Any additional monitoring required by the UIC Program Director. As with the use of surface and/or soil gas monitoring (see above comments to 1.1), AEP feels that the use of tracers is not appropriate for CCS projects. The agency notes that "tracer use is not appropriate in all situations," (page 33, top paragraph), but AEP feels that the use of tracers should be left to the discretion of the permittee. The Carbon Sequestration Council filed comments on this issue on December 23, 2008 and they are repeated here for your convenience.

> "There are at least two fundamental issues with respect to tracers. First, tracers are unlikely to enhance the protection of USDWs. This is true not just because the Class VI regulations are designed to minimize the likelihood of the kind of leakage tracers would ostensibly help detect, but because – even in the event of such a leak – tracers are not likely to be especially useful in leak detection (as discussed in the context of monitor wells, fluid monitoring in the deep subsurface provides only very localized information and is unlikely be very effective in leak detection whether or not tracers are used). Second, tracers are at least as likely to create "false positives" as to aid in the detection of actual down-hole leaks. The problem in this respect is simple: it is much easier for accidental leaks and releases to occur in the surface environment than in the deep subsurface.
>
> A final consideration is perhaps the most obvious: a requirement for tracers would be unique in the UIC program, and would unavoidably undermine public confidence in permitting determinations that – by definition – would be based on the premise that leaks from injection wells and properly permitted injection formations are extraordinarily unlikely to occur."

3.2 UIC Program Director's Evaluation of the Testing and Monitoring Plan – The guidance states that, "the submittal, evaluation, and approval of the testing and monitoring plan are meant to be part of an iterative process." (page 33, last paragraph). It goes on to state that the Director has the authority to request that the plan be revised at his or her discretion. If the Testing and Monitoring Plan will become an enforceable part of the UIC permit, AEP is concerned that frequent modifications to the permit will 1) repeatedly open the permit to public comment and 2) remove the "protection" that is afforded by such permits allowing permittees to operate on the basis of a monitoring plan that is not expected to change on an unknown schedule. If the plan were not an enforceable part of the UIC permit or if revisions to the permit were limited to a frequency of once every five years, for example, the permittee would be able to confidently operate the facility without the fear of continually changing compliance requirements.
The above comments apply not only to the Testing and Monitoring Plan, but to the Injection Well Plugging Plan, the Post-Injection Site Care and Site Closure Plan and the Emergency and Remedial Response Plan as well.

6.1 Developing the Emergency and Remedial Response Plan – The guidance states that all potentially impacted resources or infrastructure near Class VI injection wells are to be identified and may include, the "biosphere/ecosystems, the atmosphere, and the geosphere." These are very broad terms and by definition, could include every conceivable entity within the AoR. Further guidance or how to define those entities that could be affected by a CCS project or some reasonable limits on the scope of the Emergency and Remedial Response Plan would be appropriate.

III. <u>Conclusion:</u>

This concludes the comments of AEP at this time. As we work with EPA and the regulatory agencies in their implementation of the Class VI rule we may develop further comments to these guidance documents which we will share with EPA. For the time being, thank you for this opportunity to comment on the Draft Undeground Injection Control (UIC) Program Class VI Guidance Documents. If you have any questions or need any additional information about these comments, please contact Elizabeth Gunter [redacted]

Sincerely,

Elizabeth Gunter

L. Elizabeth Gunter

Cc: John McManus
Janet Henry
Gary Spitznogle
Timothy Lohner
Indrajit Bhattacharya
Frank Blake

C12 Energy

May 31, 2011

U.S. Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, DC 20460

Re: Draft Underground Injection Control (UIC) Program Class VI Well Construction Guidance for Owners and Operators

To Whom It May Concern:

C12 Energy firmly believes in thorough regulation of geologic carbon sequestration. As leaders in this industry, we will take every step to ensure that carbon is stored safely in geologic formations.[1] We consider the recently finalized Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO_2) Geologic Sequestration (GS) Wells (*UIC Rules*), and the associated guidance documents, to be the most important part of the regulatory landscape for carbon sequestration.[2] We appreciate the opportunity to provide the following comments on the Draft Underground Injection Control (UIC) Program Class VI Well Construction Guidance for Owners and Operators (*Well Construction Guidance* or *Guidance*).[3]

The UIC Rules and the associated Well Construction Guidance are a step in the right direction toward suitable regulation of CO_2 storage sites. We hope that our comments on the Draft Well Construction Guidance Document help to improve the quality of CO_2 storage regulation. We would be happy to discuss any aspects of these comments with EPA.

Sincerely,

B. R.

Barclay Rogers
Director of Development

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[1] C12 Energy is the leading CO_2 storage project developer in the United States. To date, we have secured CO_2 storage rights to approximately 370,000 acres of privately-owned land with 13 projects in 10 different states, corresponding to approximately 10 billion tons of CO_2 storage capacity distributed throughout the nation. To put this in context, our sites are currently sufficient to permanently store CO_2 emissions from approximately 15% of the nation's fleet of coal plants for the next 30 years, and we're developing more capacity every day.

[2] http://www.gpo.gov/fdsys/pkg/FR-2010-12-10/pdf/2010-29954.pdf (hereinafter UIC Rules).

[3] http://water.epa.gov/type/groundwater/uic/class6/upload/GS_Well_Construction_Gudiance_DRAFT-FINAL-030911.pdf (hereinafter Well Construction Guidance or Guidance)

Berkeley, CA | Bloomington, IL | Cambridge, MA | Denver, CO | 617.674.2478 | www.c12energy.com

1 Corrosion Considerations (Section 2.4.2)

1.1 Description

Regarding the maximum allowable water content of the injectate stream / corrosion-resistant materials of the well, the Guidance states:

> If the water content of the injectate stream is higher than 50 ppm, then corrosion-resistant materials are suggested on all components of the injection well that would come into contact with the carbon dioxide stream.[4]

The limit of 50 ppm does not seem to be related to any particular study on this topic. While it is true that most of the existing CO_2 streams in operation adhere to 50 ppm as an upper limit, this has been driven in large part by the absence of water from the process in the first place. Based purely on corrosion considerations, up to 500 ppm was deemed acceptable by independent experts for pipelines.[5]

1.2 Necessary Changes

EPA should revise the water content limitations to be consistent with corrosion resistance tests done by independent entities. As noted above, at least one study suggests the limit should be 500 ppm, not 50 ppm as noted in the Well Construction Guidance.

2 Packer Positioning (Section 2.6)

2.1 Description

The Guidance states with regards to "Selecting the Tubing and Packer" that:

> Therefore, to obtain the best measurement of the quality of the cement bond through the confining layer as possible, EPA recommends placing the packer <u>near the top of the confining layer</u> to obtain the best results.[6]

The EPA seems to recommend placing the packer near the top of the confining zone (instead of the bottom). This is inconsistent the well diagrams that are included in the Guidance (Figure 3), and also with common practice of placing the injection packer as close to the perforated interval as possible, in order to bring in instruments such as passive seismic geophones, pressure, and temperature probes all as near the injection perforations as possible.

2.2 Necessary Changes

In order to accomplish safe injections, allowing for direct and indirect measurements of plume and pressure performance, in accordance with the UIC Rules[7] the passage from the Guidance excerpted above should be altered as follows:

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[4] Well Construction Guidance, p. 13.

[5] See Erika de Visser, Chris Hendriks, Maria Barrio, Mona J. Mølnvik, Gelein de Koeijer, Stefan Liljemark, Yann Le Gallo, "Dynamis CO2 quality recommendations", International Journal of Greenhouse Gas Control 2, p.478 – 484, (2008).

[6] Well Construction Guidance, p. 22 (emphasis added).

[7] 40 CFR §146.90 states (in part):

"Testing and monitoring associated with geologic sequestration projects must, at a minimum, include:

"Therefore, to obtain the best measurement of the quality of the cement bond through the confining layer as possible, <u>and to allow for crucial monitoring instruments to be placed as close as possible to the injection perforations</u>, EPA recommends placing the packer above the perforated interval in the injection formation ~~near the top of the confining layer to obtain the best results~~."

3 Annular Pressure (Section 3.2)

3.1 Discussion

The Guidance notes regarding annulus pressure:

> The GS Rule requires that annular pressure between the tubing and the casing be maintained higher than the injection pressure and that the annulus be filled with a non-corrosive fluid [§146.88(c)].[8]

The Guidance explains the rationale as follows:

> This requirement provides a continuous check on the integrity of the well. If holes develop either in the casing, tubing, or packer the pressure and fluid volume in the annulus will begin to change. In addition, if the pressure in the annulus is higher than the injection pressure, any leak in the tubing will not result in fluid escaping. Instead fluid from the annulus will flow into the tubing. Using a non-corrosive fluid in the annular space prevents corrosion of the tubing or casing by the annular fluid.[9]

We are concerned that maintaining annular pressure higher than the operating injection pressure may endanger a USDW. Consider for instance a situation where CO_2 is to be injected at a depth of some 1200 m into a reservoir with initial pressure equal to hydrostatic pressure, i.e. ~ 120 bar. If one injects CO_2 at 152 bar (downhole pressure), this CO_2 needs to be close to 80 bar at the surface.[10] Consequently, the annular pressure needs to be at least 80 bar near the surface (to satisfy the intent of the GS Rule), or even greater than 152 bar (in the strictest interpretation of the GS Rule). A pressure of 80 bar near the surface is clearly well above the fracture pressure. In fact, with 80 bar at surface, the pressure in the annulus is higher than fracture pressure down to a depth of 1000 m.[11] Consequently, any leak in the casing will not simply be detected by a drop in annular pressure, it will also generate a fracture, potentially endangering USDW.

(g) Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g. the pressure front) by using:
(1) Direct methods in the injection zone(s); and
(2) Indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the Director determines, based on site-specific geology, that such methods are not appropriate.

[8] Well Construction Guidance, p. 27.

[9] Well Construction Guidance, p. 27.

[10] The injection pressure of 152 bar is an assumed number to simplify the arithmetic. Assume for simplicity that the CO_2 density is 600 kg/m^3, so that it builds 72 bar of hydrostatic pressure in a well of 1200 m depth. Since the bottom hole pressure needs to be 152 bar, surface pressure must be (152 – 72) = 80 bar.

[11] Assuming that fracture pressure (P_F) is 80% over hydrostatic pressure (P_H), and that $P_H = 10^4$ d (d in meters, P_H in Pascals), then $P_F = 1.8 \times 10^4$ d. The pressure in the annulus (P_A) also rises hydrostatically, starting from 80 bar, i.e. $P_A = 8 \times 10^6 + 10^4$ d (d in meters, density of annulus fluid assumed to be the same as the density of water), so $P_A = P_F$ when $d = (8 \times 10^6)/(0.8 \times 10^4) = 1000$ m.

3.2 Necessary Changes

The UIC Rules state that:

> The owner or operator must fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the Director. The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the Director determines that such requirement might harm the integrity of the well or endanger a USDW.[12]

The Guidance should be revised to recognize the potential for annulus pressures greater than injection pressures to endanger USDWS, and should authorize the Director to deviate from this requirement if "such requirement might harm the integrity of the well or endanger a USDW" as provided for in the UIC Rules.

[12] 40 CFR §146.88(c) (emphasis added).

BEFORE THE UNITED STATES
ENVIRONMENTAL PROTECTION AGENCY

Guidance documents to support the Class VI Rule under the Underground Injection Control (UIC) Program	)	**EPA-HQ-OW-2008-0390**

Comments of:
Clean Air Task Force
Clean Water Action
Natural Resources Defense Council

A. Introduction

The **Clean Air Task Force**, **Clean Water Action** and the **Natural Resources Defense Council** thank the United States Environmental Protection Agency (EPA) for the opportunity to comment on the four Guidance Documents to support the Class VI rule under the Underground Injection Control (UIC) Program.

Clean Air Task Force ("CATF") is a nonprofit organization dedicated to reducing atmospheric pollution, including the air pollutants that cause climate change, through research, advocacy, and private sector collaboration. CATF's Coal Transition Project in particular seeks climate solutions for the U.S. coal fleet, including by advancing the careful implementation of carbon capture and sequestration technology.

Clean Water Action is a national citizens' organization of 1.2 million members and is active in over a dozen states. Clean Water Action works for strong public health and environmental protections with an emphasis on those that impact water resources. Clean Water Action has a long history of work on drinking water and on Safe Drinking Water Act implementation including the Federal Requirements under the Underground Injection Control Program for Carbon Dioxide Geologic Sequestration Wells.

The **Natural Resources Defense Council** (NRDC) is a national, nonprofit organization of scientists, lawyers and environmental specialists dedicated to protecting public health and the environment. Founded in 1970, NRDC has more than 1.2 million members and online activists nationwide, served from offices in New York, Washington D.C., San Francisco, Los Angeles, Chicago and Beijing.

We commend EPA for producing these draft guidance documents that must form a robust basis for state and EPA regional regulatory staff to implement the Class VI rule. In general, we believe that the four documents are sound and urge EPA to maintain their general content. In addition, we offer technical comments to the documents below, seeking clarification or recommending technical improvements in a few select areas.

B. General Comments

1. EPA should include specific discussions and guidance, where appropriate, for cases where sequestration is taking place in hydrocarbon reservoirs or in conjunction with Enhanced Oil Recovery.

Sequestration in hydrocarbon reservoirs or in conjunction with Enhanced Oil Recovery is underrepresented or missing in the draft guidances. EPA should anticipate and discuss the special circumstances present in these fields and include guidance text accordingly. Areas where those reservoirs merit special discussion include, for example:

- Draft Site Characterization and Planning guidance: Where substantial information already exists on the subsurface reservoir and area of review (AOR), EPA should discuss methods to undertake appropriate reservoir characterization. Conversely, in some EOR fields, more work may be needed relative to saline reservoirs to determine the mechanical condition of the reservoir and geological seal(s) following many years of water or gas flooding. In oil and gas fields emphasis should focus on identifying old recorded and unrecorded wellbores that may be inadequately plugged and abandoned could lead to leakage without corrective action. Withdrawal of hydrocarbons or previous enhanced recovery techniques such as water or CO_2 flooding may have adversely impacted the geochemical and mechanical characteristics of the injection site as a repository for CO_2;
- Draft Well Construction guidance: Practices such as water-alternating-gas injection can have important implications for well construction materials due to the corrosive characteristics of CO_2 in the presence of water, for example;
- Draft Area of Review and Corrective Action guidance: CO_2 Injection in the presence of hydrocarbons, including miscible flooding, can materially affect modeling. EPA should discuss the important implications for computational models, as well as implications for corrective action where higher well density and potentially large numbers of old wells can have important implications.

2. The term "cement bond log" should be avoided as a general term, or its use defined and clarified.

In a number of places in the draft guidances, EPA uses the term "cement bond log". This term commonly refers to a technique which is currently outdated and which has significant drawbacks, such as not revealing the nature or shape of any voids in the cement but instead representing an average estimate of void space. We recommend that the term be substituted with a generic term such as "cement mapping tool".

3. EPA should strongly recommend in the guidance that GS site operators inform water users and utilities of their plans well in advance and consult them regarding possible future use of an aquifer not designated as a USDW when an injection site is being selected.

While large, saline formations with greater than 10,000 mg/L TDS may be ideally suited for geological sequestration, local and regional water needs must be considered given the possibility that aquifers not presently meeting the threshold criteria for a USDW might be needed in future years for drinking water. This is a particular consideration where water shortages are presently occurring, and given recent advancements in desalination technology.

C. Comments on the Draft Underground Injection Control (UIC) Program Class VI Well Site Characterization Guidance for Owners and Operators

We express our support for the approach outlined in the document, which recommends certain prudent practices even though the rule language does not explicitly require them (for example, the recommendations in Section 2.2). We offer the following brief comments:

1. The term "potential seismic risk" should be refined to "unacceptable seismic risk" (Executive Summary, p. ii).

The existence of risk, by definition, is not a threshold for a decision. Seismicity can take place from a very small scale that is of no concern to a large scale that could be the cause for an alternative site selection. EPA should clarify.

2. EPA should further discuss why multiple log suites are necessary for more precise interpretation of the subsurface (p. 18-19).

We agree with EPA that multiple log suites are necessary to obtain the necessary information during site characterization. However, different logging tools have different levels of vertical resolution, with some being able to provide data at the scale of inches while others may average over several feet. High-resolution logs can help aid in identifying flow units and fine scale changes in porosity and permeability that may affect injectivity. EPA should provide further explanation along these lines in support of this recommendation.

3. EPA should include a discussion of resistivity logs (p. 19).

One of the most commonly used log suites is termed the "triple-combo". This includes gamma ray, density/porosity logs and resistivity logs. Resistivity logs are commonly used to distinguish water-filled pore space from hydrocarbon-filled pore space. EPA should discuss resistivity logs in this section.

4. EPA should include a discussion of gas detectors and chromatographs as a tool to identify stratigraphic zones that may need to be isolated behind the casing and cement (p. 24).

A gas detector or gas chromatograph, either used alone or in combination with mud logs, can be used to determine the presence and composition of gas encountered in the wellbore. "Shows" or "kicks" can be used to help determine which formations or intervals may have commercial/producible quantities of gas, and therefore need to be isolated behind casing and cement.

5. EPA should include a discussion of Special Core Analysis (p. 25).

Special Core Analysis (SCAL) work should also be considered for underground injection projects, in addition to routine core analysis. These more detailed tests can provide information on mineralogy and petrology, injectivity, wettability, relative permeability, fluid compatibility, capillary pressure, rock mechanical properties, seismic properties, and others.

6. EPA should explicitly discuss the role of laboratory tests on core samples to aid in geomechanical characterization.

Table 3-3 has a parameter labeled "rock strength" and the "additional information" column references laboratory testing procedures for rock mechanical properties. However, this type of testing is not systematically discussed in the text. Because, in many regions, reservoirs and seals are under tectonic stress, EPA should include a discussion of laboratory geomechanical characterization and the importance of determining rock fracture criteria. Moreover, EPA should provide recommendations for its use, particularly in the context of regional stress and strain fields, and the ability of the reservoir rock and geological seal(s) to withstand incremental injection pressures.

D. Comments on the Draft Underground Injection Control (UIC) Program Class VI Well Construction Guidance for Owners and Operators

We offer the following technical comments on this document:

1. EPA should include a discussion of the nature of injectate under Corrosion Considerations (p. 12).

In addition to the water content of the carbon dioxide, it is also necessary to consider whether water itself will be injected. In Enhanced Oil Recovery projects, for example, operators sometimes chose to alternate CO_2 injection with water injection (referred to as Water Alternating Gas, or WAG). The presence of water has a direct effect on corrosion.

2. EPA should provide more detailed guidance on selecting the appropriate cement formulation (p. 22).

EPA states that "the conditions the cement will experience can be predicted and the cement designed to better resist those conditions" but does not provide any details on how to perform such an evaluation or what selection criteria to use. Further details in needed in order to aid operators and Directors.

3. EPA should consider the drawbacks of its recommendations on packer placement and clarify the nature of its recommendation (p. 22).

The guidance states that, to obtain the best measurement of the quality of the cement bond, EPA recommends placing the packer near the top of the confining layer. This is a confusing recommendation, as when the well is initially logged to determine cement integrity and placement, it would be logged before the tubing and packer are installed. It is not clear whether this recommendation is meant to address logging later in the life of the well. Logging through tubing also presents a risk of getting logging tools stuck in the well due to the small diameter. EPA should rewrite its recommendation and include separate discussions of the initial cement evaluation logging run, which will occur prior to commencement of injection, and subsequent logging runs that will occur when the well is operating as an injector.

For the initial logging run the tubing and packer will not be installed in the well and therefore the ability to obtain the highest quality measurement will not be dependent on packer placement. Furthermore, packer placement should be based on operational considerations, such as minimizing the amount of production casing that will come into contact with the injectate, and not on the ability to obtain cement evaluation logs. For subsequent cement evaluation, when the tubing and packer are installed, EPA should include a discussion of the various options for obtaining logs and pros and cons of each. One option would be to pull the tubing and packer from the well. The benefit of this option is that the cement evaluation tool will be able to make contact with the production casing but removing the tubing and packer can result in mechanical integrity or operational risks. The second option would be to log through the tubing. The benefit of this option is that the tubing and packer do not have to be removed from the well but the log will be of lower quality and there is also a risk of getting the logging tools stuck due to the smaller diameter of the tubing.

E. Comments on the Draft Underground Injection Control (UIC) Program Class VI Well Project Plan Development Guidance for Owners and Operators

We support the recommendation to revise or adjust portions of the project plans as additional data become available during the site characterization process. We also support the recommendation that the owner or operator revisit and revise the operational-phase plans (e.g., the AoR and Corrective Action Plan, Testing and Monitoring Plan, and Emergency and Remedial Response Plan) as necessary once the AoR modeling has been completed. We also agree with the notion that exceeding the rule's minimum requirements may facilitate safer, cheaper and faster administration and project operation in the future. However, we offer the following technical comments (referencing Sections – appendices should also be amended accordingly):

1. EPA should amend Table 1 to include the possibility of new monitoring methods following a revision of the AoR and Corrective Action Plan.

A revision of the AoR and Corrective Action Plan may not only necessitate adding monitoring locations to the Testing and Monitoring Plan, but may also necessitate new monitoring methods. If the revised AoR includes new geology or features like faults or wells, operators should consider implementing new monitoring methods that might be better suited to detecting CO_2 migration or leakage, in addition to designating new monitoring locations.

2. EPA should include a description of possible conditions which would warrant not revising the site computational model when re-evaluating the AoR (p. 13).

The guidance document covers a comprehensive list of parameters that should be considered when an AoR re-evaluation also calls for the revision of the site computational model. However, it is important for EPA to list valid and justified conditions which may not warrant a model modification. This should be done both in order to list minimum recommended criteria and thresholds that would prevent unacceptable shortcuts being taken by operators, and also to provide clarity to operators as to when they can expect not to have to revise their model.

3. EPA should include a discussion of potential reasons which would render the use of indirect plume tracking methods infeasible (p. 30-31).

EPA should list a number of legitimate and justified potential reasons which would constitute valid grounds for the Director waiving the requirement for indirect plume tracking methods. This should be done in order to avoid invalid claims of infeasibility, and in order to inform a Director's decision with specific scientific and technical criteria.

4. EPA should include a rationale and strong recommendation that GS site operators should determine in advance, stable carbon isotopic signatures of both the injected and the naturally occurring CO_2 in the AoR alongside the discussion about tracers (p. 32-33).

Recent events at Weyburn have demonstrated the importance of being able to distinguish between naturally occurring CO_2 above the EOR field and the CO_2 injected from anthropogenic sources. Moreover, stable carbon isotopic signatures can accomplish similar objectives to the use of tracers. EPA should include a discussion of the use of stable carbon isotopes and provide a recommendation in Section 3.1.9.

5. EPA should discuss and recommend as a critical component of a proposed Testing and Monitoring Plan (and the monitoring in the post-injection phase as part of the Post Injection Site Care and Site Closure Plan) to provide immediate warning for timely activation of the Emergency and Remedial Response Plan (p. 33, 45).

In addition to the five listed factors in the draft Guidance, EPA should include the ability of a Testing and Monitoring Plan and Post Injection Site Care and Site Closure Plan to detect deviations from normal operating conditions by establishing thresholds which would necessitate an immediate response and activation of actions listed in the Emergency and Remedial Response plan. This is a crucial function of a monitoring plan and a prerequisite for its completeness, as the success of the Emergency and Remedial Response Plan depends on it. EPA should describe the components of an early warning system that is sufficiently robust so as to warn the GS site operator, as well as when and how to respond. For example, at the Gulf Coast Carbon Center's Cranfield Reservoir Phase III test site in Misssissippi, researchers have demonstrated the ability of satellite technology to immediately relay deviations in injection reservoir pressure from a monitoring well to the operator of the site. The same comment applies to the Post Injection Site Care and Site Closure Plan for the period after injection has ceased.

6. Along similar lines, EPA when evaluating an Emergency and Remedial Response Plan, EPA should examine whether response can be initiated in a timely fashion based on detection mechanisms (p. 51).

In addition to the factors listed in the draft Guidance that the Director should use to evaluate the Emergency and Remedial Response Plan, particular attention should be given to the feasibility to initiate emergency and remedial response in a timely manner. Among other factors, this will depend on the ability to detect the exceedance of key parameters and monitored values. A rapid response is often crucial in minimizing and preventing further damage and to reducing the degree of remediation needed. Even if the Emergency and Remedial Response Plan identifies the right course of action, the Plan's sufficiency should also be evaluated against the ability to initiate it in time. This ties in with our immediately preceding comment on the ability of the Testing and Monitoring Plan to detect the necessary changes in a timely fashion.

F. Comments on the Draft Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance for Owners and Operators

We offer the following technical comments on this document:

1. EPA should include a discussion of miscible fluids in the guidance for Computational Modeling (p. 6).

The draft guidance in its discussion of Computational Modeling is largely silent on the topic of miscible injection. This is an important topic of consideration for EOR projects and has implications for fluid dynamics and modeling. For example, the minimum miscibility pressure is affected by formation pressure and temperature and fluid chemistry. Miscible fluids will also have different fluid dynamics from immiscible fluids. These factors must be properly accounted for in a reservoir simulation model in order to make accurate predictions. EPA should include a discussion of those factors that are important to modeling miscible flooding.

2. EPA should provide more specific guidance on what conditions in a well plugging records review should trigger field testing (p. 47).

As noted by EPA, well integrity inevitably degrades over time. Even if records indicate that a well has been properly plugged and abandoned, records cannot provide information on current integrity of the casing, cement, plugs, etc. EPA should consider providing guidance on what conditions, other than indications of improper plugging, would trigger field testing, e.g. age of the well, method by which the casing was cemented, cement composition, cement placement and location, etc.

3. EPA should not treat geophysical survey results as comparable to modeling predictions (p. 60).

EPA states in the draft Guidance that "[…] geophysical survey results are comparable to modeling predictions" (p. 60). Although we understand the informative nature of spatial information resulting from geophysical surveys, we do not believe that equating a modeling prediction with an actual, physical measurement is appropriate. The former is based on assumptions and is an approximation of reality, whereas the latter is an actual measurement. Therefore EPA should clarify the language in this section to avoid confusion and state clearly that geophysical survey results may be superior to model results, but not in all cases.

G. Conclusion

We appreciate the opportunity to provide comments to EPA on these important draft guidance documents, and commend the Agency for its efforts in compiling these. We collectively stand in support of the guidance documents, their approach, structure and content, pending the above technical clarifications and revisions.

We look forward to continuing to work with the Agency on the additional upcoming guidance documents as well as the implementation of the Class VI rule, as well as other efforts under the Agency's existing authority to address the significant problem of climate change in the near term.

Respectfully submitted on May 31st, 2011,

George Peridas, Natural Resources Defense Council
111 Sutter St, 20th Floor, San Francisco, CA 94104, [redacted]

Briana Mordick, Natural Resources Defense Council
1200 New York Ave NW, Suite 400, Washington, DC 20005, [redacted]

L. Bruce Hill, Clean Air Task Force
18 Tremont St., Boston, MA 02108, [redacted]

Lynn Thorp, Clean Water Action
1010 Vermont Ave NW, 4th Floor, Washington, DC 20005 [redacted]