Southern Utah Wilderness Alliance
Petition for Review
UIC Permit UT22291-10328

Exhibit Four

Response To Public Comments

On

EPA Permit Number: UT22291-10328

for

RBU 1-10D Class II Enhanced Oil Recovery Well

in the

River Bend Unit

Uintah County, Utah

Issued to

Gasco Energy, Inc.

Background

In July 2014, staff of the U. S. Environmental Protection Agency (EPA) prepared Underground Injection Control (UIC) Draft Permit Number UT22291-10328. The Final Permit will authorize the construction and operation of the RBU 1-10D Class II UIC well to inject produced waters underground for the purpose of contributing to an enhanced oil recovery project in the River Bend Unit as proposed by Gasco Energy, Inc. (Gasco). In accordance with the federal public notice regulations, public notice of the EPA's Draft UIC Permit was posted in the Uinta Basin Standard and the Vernal Express, with the public notification period ending August 15, 2014.

EPA received comments from one commenter regarding water quality descriptions and determination, well construction description, and the project description considerations. The comments, attached to this document as Attachment A, were the only public comments received by the EPA.

The EPA provided public notice of its intent to issue a permit to Gasco for a Class II injection well. EPA did not receive any comments during the comment period but received comments from the Southern Utah Wilderness Alliance 11 days after the formal deadline of August 15, 2014. While EPA is not required to consider comments received outside of the comment period, in this instance, EPA decided to consider the comments in its decision-making process. Although EPA chose to consider these comments received outside the comment period, EPA makes these determinations on a case-by-case basis, and there should be no expectation that this will occur for future permit decisions. A summary of the issues presented in these comments and EPA's responses to those concerns, are discussed below:

Well Construction

Comment #1: The commenter expressed concern that the design and construction of the proposed injection well and nearby offset wells are not sufficient to protect USDWs. More specifically, the commenter is concerned that a portion of the annular space adjacent to the USDW is uncemented because of the lack of cement between the estimated top of cement between the Production casing and the formation wall and the bottom of cement behind the Surface casing.

The commenter further states that:

> Failing to extend surface casing in any well to below the base of the lowest USDW puts those USDWs below the base of the surface casing at significant risk of contamination. Cross flows may occur between the USDW and other formations, potentially leading to contamination of the USDW. Leaving a potential flow zone uncemented can also result in overpressurization of the annulus and/or result in casing corrosion, both of which may lead to a well integrity failure, further putting drinking water at risk. Properly constructed wells typically have at least two barriers between USDWs and fluids contained in the well: 1) the surface casing and 2) the production casing. These redundant barriers are necessary to ensure that if one barrier fails USDWs are still protected. The proposed injection well and offset wells lack redundant barriers, putting USDWs at serious risk in the case of a well integrity failure.
>
> The American Petroleum Institute recommends that "surface casing be set at least 100 feet below the deepest USDW encountered while drilling the well." Both UIC Class I and Class VI well rules require surface casing to extend below the base of the lowest USDW, indicating that EPA clearly recognizes this as an important standard to protect groundwater.

EPA Response: It appears that the commenter is concerned with a potential for mechanical integrity issues to arise due to the way this well will be cemented. Mechanical integrity is defined at 40 CFR 146.8. The commenter's concerns are in regard to the second prong of this definition. This says that "an injection well has mechanical integrity if: there is no significant fluid movement into an underground source of drinking water through vertical channels adjacent to the injection well bore." 40 CFR 146.8(a)(2). The regulations further describe the methods that must be used to determine the absence of significant fluid movement. 40 CFR 146.8(c). In this case, EPA has determined that the applicant has adequately demonstrated mechanical integrity via 40 CFR 146.8(c)(2).

EPA Region 8 Groundwater Section Guidance Number 34 (http://www2.epa.gov/sites/production/files/documents/R8UIC-GUIDE34.pdf), in the evaluation of well Mechanical Integrity, instructs permit reviewers to review the well's Cement Bond Log (CBL) to determine the adequacy of the cement to prevent fluid migration under 40 CFR 146.8(c). The CBL must show a Cement Bond Index (CBI) of at least 80% for a span of 18 consecutive feet (for 5 ½ inch pipe) in the injection zone's overlying confining zone. This will verify that seepage is unlikely to occur, between the injection zone and any adjacent USDWs. The top of cement is above the confining zone, and there is no requirement for it to go above the bottom of the surface casing. The base of the USDW is covered under Appendix E, Plugging and Abandonment Requirements.

Since a greater than 80% CBI could not be confirmed by the analysis of the CBL in this case, the operator is additionally required, as part of the permit, to determine the absence of significant fluid movement into a USDW through vertical channels adjacent to the injection well bore by conducting a Radioactive Tracer Test (RTS) as a procedure to identify the presence or absence of vertical fluid movement behind the casing near injection perforations. The RTS is used to supplement data from approved Part II demonstrations. If channeling behind casing is detected, the RTS can also be used to evaluate the vertical extent of fluid movement. In addition, if the results of the radioactive tracer test were to fail, additional testing would need to be performed. If those tests indicate that an adequate seal still could not be confirmed, the permit (authorization to inject) would be denied and the operator would be allowed to rework the well to achieve the acceptable criteria, if the operator desires, or otherwise plug and abandon the well as per the permit requirements.

The USEPA considers this approach to be protective of USDWs and complies with CFR requirements concerning permitting of Class II injection wells.

Injection Pressure

Comment #2: The commenter expressed concern that the MAIP is set too high and may allow the injection to fracture the confining zone. The commenter stated that "the MAIP should not be equal to, but rather should be less than, the fracture pressure of the confining zone and incorporate an appropriate safety factor."

EPA Response: We agree. The conservative equation we use calculates formation fracture pressure (FFP) using the top of the injection interval as the value for depth, which is a more conservative value than the already conservative value of the FFP at the top perforation. Using the top perforation would account for a larger depth value in the following equation:

MAIP = MSIP = [FG – (0.433*SG)] * (Depth to Top of Injection Interval)

MSIP = Maximum Surface Injection Pressure
SG = Specific Gravity
FG = Fracture Gradient of injection interval

Therefore, using the Depth to the Top Perforation would allow for a higher MAIP. While this is also an acceptable method of calculating the MAIP, we are using the more conservative "top of the injection interval" depth. Furthermore, the perforations are in the injection zone only and fracturing in this interval is allowed. There is no danger of fracturing in the above confining layer comprised primarily of black shale.

The equation meets the requirement stipulated in 40 CFR 146.23(a)(1) that reads:

> Injection pressure at the wellhead shall not exceed a maximum which shall be calculated so as to assure that the pressure during injection does not initiate new fractures or propagate existing fractures in the confining zone adjacent to the USDWs.

While the commenter proposes a method that is even more conservative, EPA's conservative approach allows for the protection of USDWs and complies with the UIC regulations.

Reservoir Stimulation

Comment #3: The commenter is concerned about a potential discrepancy in the application. The commenter indicates that while the permit application states that no additional stimulation is anticipated for the proposed well, attached Exhibit L-1 indicates that they may perforate and frack the shown intervals. The commenter wants to ensure that the discrepancy is resolved and any potential hydraulic fracturing or other reservoir stimulation be disclosed for public review and comment and approved by EPA.

EPA response: As stated on Page 9, Section F of the permit application no stimulation is *expected* to be required. However, formation fracturing is allowed in the injection zone in accordance with log and test requirements stipulated in the permit. This is different than fracturing the confining zone, which is not authorized by the permit. If fracturing of the injection zone occurs and meets the conditions of the permit, adjacent USDWs will be protected.

Area of Review

Comment #4: The commenter believes that a fixed ¼ mile area of review is not sufficient to protect USDWs and asserts that EPA must require the applicant to more accurately determine where injected fluids will flow. They also suggest that the EPA should have considered using the "zone of endangering influence" or "ZEI" to determine the area of review.

EPA Response: As the commenter points out, the UIC regulation at 40 CFR 146.6 allows for the area of review to be determined by either a fixed radius *or* by calculating the zone of endangering influence. 40 CFR 146.6 states "the Director may solicit input from the owners of operators of injection wells within the State as to which method is most appropriate for each geographic area or field." In this case, Gasco submitted a ZEI calculation to EPA, and it was 747 feet. However, Gasco proposed a ¼ mile AOR. EPA agrees that a fixed ¼ mile AOR is appropriate because it is more conservative and protective than the 747 foot ZEI. Gasco's ZEI calculation and explanation is attached as Attachment B.

The USEPA considers this approach to be protective of USDWs and complies with CFR requirements concerning permitting of Class II injection wells.

Attachment A

August 25, 2014

To: Landon Newell, Staff Attorney, Southern Utah Wilderness Alliance
Steve Bloch, Attorney, Southern Utah Wilderness Alliance

From: Briana Mordick, Staff Scientist, Natural Resources Defense Council

Subject: Comments on Draft Underground Injection Control Permit UT22291-10328, Class II Enhanced Oil Recovery Well, RBU 1-10D, API No.: 43-047-34312, Uintah County, UT

This report responds to the request of the Southern Utah Wilderness Alliance ("SUWA") for a technical review of the Draft Underground Injection Control Permit UT22291-10328, Class II Enhanced Oil Recovery Well, RBU 1-10D, API No.: 43-047-34312, Uintah County, UT. I have reviewed the draft permit and supporting documents and detailed my comments below. My CV detailing my qualifications to provide this technical review is attached.

The permit applicant, Gasco, and the Environmental Protection Agency ("EPA") have not sufficiently demonstrated that the proposed injection well will not endanger Underground Sources of Drinking Water ("USDWs").[1] Specifically, as discussed in greater detail in the comments that follow:

- The proposed injection well and offset wells are not properly designed and constructed and may currently be endangering USDWs
- The proposed maximum allowable injection pressure ("MAIP") in the draft permit may result in fracturing of the injection or confining zone, potentially creating pathways that may allow injected fluids to reach USDWs
- The Area of Review ("AoR") evaluation is not sufficient and neither the applicant nor EPA has demonstrated that the proposed ¼-mile fixed radius is appropriate to protect USDWs.

Consequently, the draft permit should not be approved unless and until these deficiencies are addressed.

Well Construction

The design and construction of the proposed injection well, the RBU 1-10D, and nearby offset wells are not sufficient to protect USDWs.

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[1] As noted in the draft permit, the Base of Moderately Saline Water (BWSW) corresponds with the base of the USDWs in the area. However, no analyses of water from this interval were provided in the permit application.

In the permit application, the base of the deepest USDW in the proposed injection well is estimated at 2523 feet. However, the surface casing, which is intended to isolate and protect usable groundwater, is set at 2414 feet. Furthermore, the top of cement behind the production casing is estimated to be at 2980 feet. In other words, the surface casing does not extend below the base of the USDW and the production casing cement does not extend above the base of either the USDW or the surface casing. This means that a portion of the annular space adjacent to the USDW is uncemented. Leaving this annular space uncemented puts both the USDW and well integrity at risk.

The surface casings for the wells identified in the permit application as being within or near the ¼-mile AoR are set significantly shallower than the surface casing in the proposed injection well. The permit application does not specify the depths to the base of the USDW for these wells. However, a review of the map of the Base of Moderately Saline Ground Water ("BMSW")[2], which, as stated in the draft permit, "corresponds to the base of the USDWs in the area," indicates that the BMSW in these offset wells is likely to be at similar depths as the BMSW in the RBU 1-10D, or approximately 2500 feet. The surface casing in all five listed offset wells does not extend below the base of the USDW.

As with the RBU 1-10D, in three of the five offset wells, the top of the production casing cement does not extend above the base of the surface casing. In one such well, the RBU 5-11D, the top of the production cement also does not extend above the base of the USDW. In this well, the base of the surface casing is at 500', the base of the USDW is at approximately 2500', and the top of the production casing cement is at 4160', meaning that almost 1650 feet of wellbore behind the production casing is uncemented.

Failing to extend surface casing in any well to below the base of the lowest USDW puts those USDWs below the base of the surface casing at significant risk of contamination. Cross flow may occur between the USDW and other formations, potentially leading to contamination of the USDW. Leaving a potential flow zone uncemented can also result in overpressurization of the annulus and/or result in casing corrosion, both of which may lead to a well integrity failure, further putting drinking water at risk. Properly constructed wells typically have at least two barriers between USDWs and fluids contained in the well: 1) the surface casing and 2) the

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[2] Anderson, P. B., Vanden Berg, M. B., Carney, S., Morgan, C., & Heuscher, S. (2012). *Moderately Saline Groundwater in the Uinta Basin, Utah, Special Study 144*. Utah Geological Survey.

production casing.[3] These redundant barriers are necessary to ensure that if one barrier fails USDWs are still protected. The proposed injection well and offset wells lack redundant barriers, putting USDWs at serious risk in the case of a well integrity failure.

The American Petroleum Institute recommends that "surface casing be set at least 100 feet below the deepest USDW encountered while drilling the well."[4] Both UIC Class I and Class VI well rules require surface casing to extend below the base of the lowest USDW, indicating that EPA clearly recognizes this as an important standard to protect groundwater.[5]

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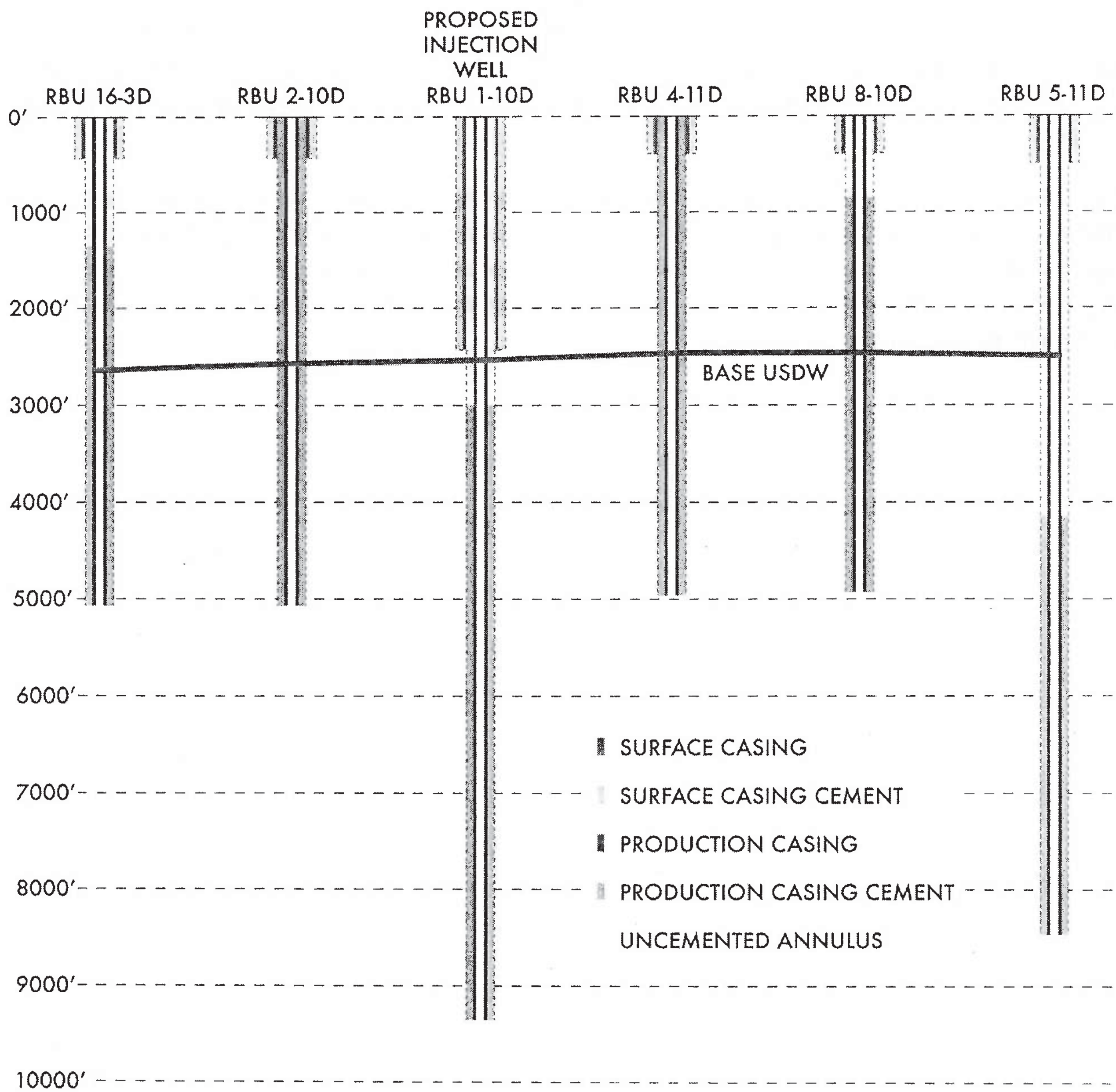
[3] Smith, J. B., & Browning, L. A. (1993, January). Proposed Changes to EPA Class II Well Construction Standards and Area of Review Procedures. In SPE/EPA Exploration and Production Environmental Conference. Society of Petroleum Engineers.
[4] American Petroleum Institute. 2009. Hydraulic Fracturing Operations – Well Construction and Integrity Guidelines. API Guidance Document HF1. First Edition, October 2009.
[5] 40 CFR 146.86(b)(2) and 40 CFR 146.65(c)(2)


PROPOSED
INJECTION
WELL
RBU 16-3D
RBU 2-10D
RBU 1-10D
RBU 4-11D
RBU 8-10D
RBU 5-11D
0'
1000'
2000'
3000'
4000'
5000'
6000'
7000'
8000'
9000'
10000'
BASE USDW
SURFACE CASING
SURFACE CASING CEMENT
PRODUCTION CASING
PRODUCTION CASING CEMENT
UNCEMENTED ANNULUS

While Class II rules do not explicitly require surface casing to extend below the base of the lowest USDW,[6] they do require that, "all Class II wells shall be cased and cemented to prevent movement of fluids into or between underground sources of drinking water,"[7] and that the depth to the bottom of all USDWs be considered in determining and specifying casing and cementing requirements.[8]

The permit application and draft permit state that corrective action is not anticipated to be necessary for either the proposed injection well or wells within or near the AoR. However, a review of the construction details indicates that, due to inadequate casing and cementing practices, both the proposed injection well and nearby offset wells may *currently* be endangering USDWs, not even taking into account the additional risks associated with converting the RBU 1-10D into an injection well. In sum, the current construction of the proposed injection well and nearby offset wells is insufficient to protect USDWs and the permit should not be granted unless and until these deficiencies are corrected.

The applicant and EPA must demonstrate that contamination is not currently occurring in the proposed injection well and offset wells, including but not limited to water sampling and analyses from the USDW interval in these wells. This information must also be provided to the public for additional review before the permit is granted.

Injection pressure

Federal Class II regulations require that,

"Injection pressure at the wellhead shall not exceed a maximum which shall be calculated so as to assure that the pressure during injection does not initiate new fractures or propagate existing fractures in the confining zone adjacent to the USDWs."[9]

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[6] A report by the General Accounting Office, an internal EPA Mid-Course Evaluation of the UIC program, and a federally chartered advisory committee found that Class II well construction rules were insufficient to protect drinking water and recommended that the rules be changed to require surface casing to extend below the base of protected water. EPA proposed to make these changes in the early 1990s, but they were never finalized. Nevertheless, these improvements are still needed in order to adequately protect USDWs and should be implemented in permitting decisions. *See* Smith, J. B., & Browning, L. A. (1993, January). Proposed Changes to EPA Class II Well Construction Standards and Area of Review Procedures. In *SPE/EPA Exploration and Production Environmental Conference.* Society of Petroleum Engineers.

[7] 40 CFR 146.22(b)(1)

[8] 40 CFR 146.22(b)(1)(ii)

[9] 40 CFR 146.23(a)(1)

The MAIP calculated in the draft permit does not meet this requirement. The proposed MAIP is too high and may endanger USDWs by allowing injected fluids to fracture the confining zone, which may create pathways through which injected fluids can migrate into the USDW.

The proposed MAIP in the draft permit is equal to EPA's estimated fracture pressure at the base of the confining zone/top of the injection zone. The MAIP should not be equal to, but rather should be less than, the fracture pressure of the confining zone and incorporate an appropriate safety factor. Class VI rules require that the maximum injection pressure be no greater than 90% of the fracture pressure of the injection zone.[10] For Class II wells, EPA Region 5 recommends adding a safety factor of 0.05 to the specific gravity of the injectate.[11]

In the draft permit, EPA states that the MAIP calculation was performed using injection fluid density and injection zone data submitted by the applicant. Despite repeated requests, EPA declined to make this information available.[12] It is therefore very difficult to evaluate the adequacy of EPA's MAIP calculation in the draft permit because EPA does not include all the inputs used to derive the MAIP, notably the specific gravity ("SG") of the injectate. By back calculating from the available information, it appears that EPA is using a SG of approximately 1.025. This is the value of SG commonly assumed for seawater due to the average density of seawater being equal to 1.025 g/ml. Seawater is commonly assumed to have an average total dissolved solids ("TDS") concentration of 35,000 mg/L. The permit application submitted by Gasco indicates that the TDS concentration of a representative sample of injection fluid is 158,679 mg/L, or approximately 4.5 times the average TDS concentration of seawater. As such, the density and therefore specific gravity of the injection fluid will be significantly higher. Assuming a standard ambient pressure and temperature of 25° C and 100 kPA, the density of water with a TDS concentration of 158,679 mg/L would be approximately 1.125 g/ml, or a SG of 1.125. Using this value of SG and the following equation to determine MAIP, which includes a safety factor:

$$MAIP_{surface} = \{[FG - 0.433 * (SG + 0.05)] * D\} - 14.7$$

where:
FG = fracture gradient (assume value used in draft permit, 0.860 psi/ft)
0.433 = density of water in psi/ft
SG = specific gravity
0.05 = safety factor
D = depth

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[10] 40 CFR 146.88(a)
[11] "Requirements for Commercial Underground Injection Control Class II Wells." *EPA Region 5 Water*. Environmental Protection Agency, n.d. Web. 20 Aug. 2014.
[12] *See* e-mail correspondence between Landon Newell, SUWA, and Tom Aalto, EPA.

14.7 = conversion factor from absolute pressure to gauge pressure

the MAIP for the RBU 1-10D would be 1637 psig, or approximately 16% lower than the EPA's proposed MAIP.

Additionally, the fracture gradient of the injection and confining zones must be confirmed with field data from the proposed well, and the MAIP must be adjusted to reflect any difference between the actual and estimated FG.

In sum, the proposed MAIP in the draft permit may be too high[13] and injecting at this pressure may endanger USDWs. The operator and EPA must:

- Resolve the apparent discrepancy between the reported salinity and density of the injectate;
- Accurately determine the density and specific gravity of the injectate;
- Use an accurate value for the specific gravity of the injectate and incorporate a safety factor in the MAIP calculation, and;
- Provide all inputs to the MAIP calculation, including the salinity and density/specific gravity of the injectate, to the public for additional review before the permit is granted.

Reservoir Stimulation

The permit application states that no additional stimulation is anticipated for the proposed well. However, Exhibit L-1 submitted by the applicant states that, "Plan call for perforating and fracking the shown intervals..." [sic]. This discrepancy must be resolved and any plan to hydraulically fracture or use other reservoir stimulation techniques must be disclosed for public review and comment and approved by EPA.

Area of Review

Under federal UIC Class II rules, the AoR may be determined using one of two methods: either a fixed radius of not less than ¼ mile or by calculating the zone of endangering influence ("ZEI"). Neither the permit application nor the draft permit consider the use of the ZEI or include a discussion of the merits of the different methods.

In 2004 the UIC National Technical Workgroup ("NTW") prepared a report entitled, "Does a Fixed Radius Area of Review meet the statutory mandate and regulatory

[13] We again note that this is difficult to evaluate due to EPA's refusal to provide the necessary data.

requirements of being protective of USDWs under 40 CFR §144.12?"[14] The purpose of the report was to summarize available information on the use of a ¼-mile fixed radius as opposed a ZEI to designate the AoR around Class II injection wells. The researchers summarized the process that led to the development of the two different AoR approaches, stating, "The final AoR regulation at 40 CFR §146.6 was adopted even though much existing evidence showed that the actual pressure influence of any authorized underground injection operation is not limited to any pre-determined radius around any proposed or existing injection well, but is a function of specific physical parameters (including initial pore pressures in both the injection zone and in the lowermost USDW and actual injection rate)."

The researchers noted incidents where injected fluids contacted improperly abandoned wells beyond a ¼-mile radius, including one case on the Texas/Louisiana border where injected fluids flowed out of orphan wells located more than a mile from the injection well, impacting a local public water supply.

Accordingly, the researchers recommended that EPA develop and adopt technical guidance regarding the AoR determination, and that every UIC program reevaluate the area of review of all authorized injection activities, stating, "The majority of EPA UIC National Technical Workgroup members understands the magnitude of the suggested action and consider this proposal as a long-term solution to *a long-standing inadequate permitting practice*." (emphasis added) The researchers went further to state, "A majority of the UIC National Technical Workgroup members believe that enough evidence exists to challenge the assumption that a fixed radius AOR is sufficient to assure adequate protection of USDWs from upward fluid migration through artificial penetrations within the pressure influence of authorized injection operations."

The isopachs provided as Exhibits J and K indicate that the injection interval does not have a uniform thickness in the vicinity of the proposed injection well, meaning that injected fluids may flow preferentially in one or more directions rather than flowing radially as the ¼-mile AoR implies. This may allow injected fluids to contact wells beyond the ¼-mile AoR. Gasco's exhibits show that many existing wells fall just outside the ¼-mile AoR. As noted above, the construction practices used in the identified offset wells are insufficient to protect groundwater. EPA lists "vertical movement of fluids through improperly abandoned and improperly completed

[14] Frazier, M., Platt, S., & Osborne, P. (2004) Does a Fixed Radius Area of Review meet the statutory mandate and regulatory requirements of being protective of USDWs under 40 CFR §144.12?. *Final Work Product from the National UIC Technical Workgroup.*

wells," as one of six key pathways of contamination through which injected fluids may reach USDWs.[15]

The fixed ¼-mile AoR is not sufficient to protect USDWs. EPA must require the applicant to more accurately determine where injected fluids will flow, in order to more thoroughly identify pathways through which injected fluids may reach groundwater.

Conclusion

The proposed injection project presents significant risks to USDWs. The draft permit should not be approved unless and until the deficiencies discussed are addressed.

[15] U.S. Environmental Protection Agency, Office of Drinking Water. (1980, May). *Statement of Basis and Purpose, Underground Injection Control Regulations.*

Attachment B

Evaluation of the Zone of Endangering Influence for the RBU 1-10D Injector

When water is injected into a reservoir, the reservoir pressure increases. The maximum pressure increase is seen at the injection wellbore and decreases with the log of distance. The zone of endangering influence surrounding an injection well is the area where this pressure increase from fluid injection could potentially cause migration of injection or reservoir fluids into an underground source of drinking water, should a path be available.

As described in Regulation 40 CFR, Part 146.6, the radius r of this zone can be determined using the modified Theis equation:

$$r = \left(\frac{2.25\ KHt}{S\ 10^{x}}\right)^{\frac{1}{2}}$$

where

$$x = \frac{4\pi\ KH\ (h_w - h_{bo} S_p G_b)}{2.3\ Q}$$

and K is the hydraulic conductivity of the injection zone, H is the injection zone thickness, t is total injection time, S is the dimensionless storage coefficient, Q is the injection rate, S_pG_b is the specific gravity of the injection fluid, h_{bo} is the initial hydrostatic head of the injection zone, and h_w is the hydrostatic head at the base of the usable water zone.

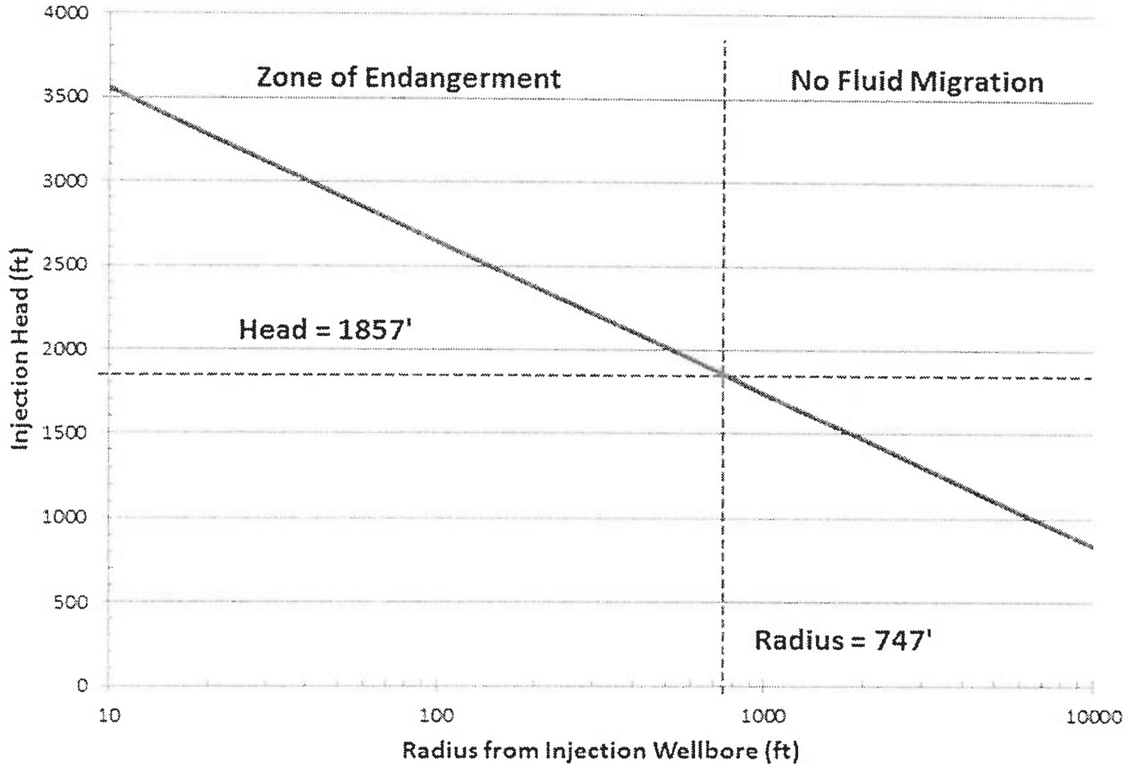
The term $(h_w - h_{bo}\ S_pG_b)$ is the difference in pressure between the injection zone and the base of the usable water zone, expressed as a hydrodynamic head. The average injection water will have a TDS of 27,000 mg/L, corresponding to a specific gravity of 1.02. According to the analysis by the USGS, the base of the usable water zone is 2523' below the surface at the RBU 1-10D. The initial injection reservoir pressure was determined from a series of fluid level measurements in surrounding wells, which were performed by Gasco in August to October 2010 (see table below).

Before measuring these levels, the wells had been shut in for periods of one month or more.

Well Name	Fluid Level (ft below surface)
RBU 2-10D	4380'
RBU 4-11D	4489'
RBU 8-10D	4649'
RBU 15-3D	4808'
RBU 16-3D	4692'

The Uteland Butte zone is very depleted; the fluid level in the RBU 2-10D showed the highest reservoir pressure. Using this value, we get a conservative measure of the hydraulic head difference $h_w - h_{bo} S_p G_b$ = (-2523 – (-4380)) = 1857 feet.

The Theis equation can be rearranged to determine the hydraulic head increase in the injection zone as a function of radius from the injection wellbore. For the specific case of the RBU 1-10D, the radius of the zone of endangerment is the radius where the hydrostatic head increase from injection exceeds 1857 feet. Results of this calculation are shown in the accompanying figure. This figure assumes an injection rate Q of 2000 bbls/day, an injection time t of 30 years, an injection zone thickness H of 12' (the height of the C-shoal member of the Uteland Butte formation in the RBU 1-10D), and a storage coefficient S of 1.2×10^{-5}. The Uteland Butte injection reservoir is naturally fractured and has had additional fracture stimulation. The hydraulic conductivity was assumed to be 1×10^{-6} m/s, corresponding to fractured reservoir with 200 micron fracture openings spaced every 16 feet. With these assumptions, the radius of the zone of endangerment is calculated to be 747'.



Conservative assumptions were used to determine the radius of 747'; relaxing these assumptions will decrease the radius of the possibly affected area. First, the reservoir thickness of 12' assumes that injection will occur only in the C-shoal formation; injecting into the entire Uteland Butte will increase the thickness to 41'. Second, the injection head of 1857' was determined using the maximum measured reservoir pressure. Using the lower average value would increase the injection head needed for possible fluid migration, decrease the radius. Third, the reservoir pressure measurements were conducted four years ago. In this time, more than 40,000 bbls of oil have been produced from the wells near the RBU 1-10D, further depleting the reservoir pressure. Finally, this calculation assumes that no liquids will be produced from the injection zone. Since the RBU 1-10D will be used as an injector for secondary oil recovery, fluid will be continuously removed from the reservoir, decreasing the rate of pressure build-up.

Item			
Formation Thickness	12	*ft*	
Permeability	106	*mDarcy*	
Specific Gravity	1.02		
Viscosity	1.06	*cP*	
Injection Rate	2000	*bbls/day*	
Time	30	*yrs*	
Formation Thickness	3.6576	*m*	
Permeability	1.06E-13	*m2*	
Density	1020	*kg/m3*	
Viscosity	0.00106	*Pa s*	
Injection Rate	0.00276019	*m3/s*	
Time	946728000	*s*	
S	1.20E-05		
K	1.00E-06	*m/s*	1.00E-06 *m/s*
UDSW	2523	*ft below surf*	
UB Head	4380	*ft below surf*	
ho - h	1857	*ft below surf*	

Radius (ft)	Radius (m)	ho - h (m)	ho - h (ft)
10	3.048	1.08E+03	3554.71
20	6.096	1.00E+03	3281.89
50	15.24	8.90E+02	2921.23
100	30.48	8.07E+02	2648.41
200	60.96	7.24E+02	2375.58
500	152.4	6.14E+02	2014.92
747	**227.6856**	**5.66E+02**	**1856.91**
1000	304.8	5.31E+02	1742.10
1320	402.336	4.98E+02	1632.82
2000	609.6	4.48E+02	1469.27
5000	1524	3.38E+02	1108.62
10000	3048	2.55E+02	835.79