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September 11, 2013

Sent via electronic mail
Stephen Platt
Class II Team Leader
U.S. EPA - Region III (3WP22)
1650 Arch St.
Philadelphia, PA 19103
platt.steve@epa.gov

Re: Comments on Supplemental Statement of Basis for Underground Injection Control Permit PASD020BCLE

Dear Mr. Platt,

The University of Pittsburgh School of Law Environmental Law Clinic submits the following comments on behalf of its client, Ms. Marianne Atkinson. These comments are submitted in response to the re-opening of the comment period for UIC Permit PAS2D020BCLE and the accompanying changes to the Statement of Basis for the proposed permit. We have attached an expert report commissioned by the Clinic and Ms. Atkinson to this comment and hereby incorporate the full expert report of Mr. Phil Grant from Terra Dynamics, Inc., into this comment.[1]

The United States Environmental Protection Agency Region III ("EPA" or "Region III") noticed Permit PAS2D020BCLE for Windfall Oil and Gas, Inc., ("Applicant" or "Windfall") on November 7, 2012.[2] The Permit at issue will authorize Windfall to operate the Zelman #1 Class II-D injection well ("Zelman Well"), in Brady Township, Clearfield County, Pennsylvania. As these comments will demonstrate, the Applicant has not met its burden to demonstrate that its injection will not cause endangerment of underground sources of drinking water. The Draft Permit in its current form contains multiple deficiencies and should be denied or significantly revised. As the endangerment standard has not been meet, EPA does not have authority to issue the permit.

[1] UIC Permit Technical Review, Windfall Oil & Gas #1 Zelman, Brady Township, Clearfield County, PA, prepared by Philip R. Grant, Senior Geologist, Terra Dynamics, Inc., Austin, TX, attached as Exhibit 1 (hereinafter Expert Report").
[2] Permit PAS2D020BCLE attached as Exhibit 2.

Legal Background

In determining whether to issue any Underground Injection Control (UIC) permit, Congress required that "the applicant for the permit to inject must satisfy the [permitting authority] that the underground injection will not endanger drinking water sources."[3] Congress established a minimum standard for endangerment of drinking water sources as the following:

> Underground injection endangers drinking water sources if such injection may result in the presence in underground water which supplies or can reasonably be expected to supply any public water system of any contaminant, and if the presence of such contaminant may result in such system's not complying with any national primary drinking water regulation or may otherwise adversely affect the health of persons.[4]

EPA has issued regulations that define the underground sources of drinking water (USDWs) that must be protected as "an aquifer or its portion…which contains a sufficient quantity of ground water to supply a public water system; and…contains fewer than 10,000 mg/l total dissolved solids."[5]

I. The Supplemental Statement of Basis does not allow for a meaningful opportunity for the public to comment on EPA's determination.

EPA defends its seismicity determination in the Supplemental Statement of Basis by identifying limits on the rate, volume, and maximum pressure of injected fluid. Yet, the public cannot adequately critique the EPA's determination of the risk to USDWs from the authorization of operation of the Zelman Well without additional information on EPA's (not the Applicant's) maximum injection pressure and area of review calculations. EPA's rules require that a statement of basis "…briefly describe the **derivation** of the conditions of the draft permit and the **reasons** for them…."[6] In the Statement of Basis, EPA lists the factors that it is required to consider in determining the area of review. Unfortunately, EPA never identifies the specific pressure increase calculations around the proposed wells over the lifetime of those wells. EPA does not identify the permeability value for the injection zone that *EPA*, not the Applicant, used to determine that a fixed area of review (¼ mile) was acceptable to EPA. The public cannot accurately critique EPA's decision on the area of review without an explanation of EPA's full calculation of the zone of endangering influence used to confirm the validity of the default ¼ mile area of review. Without the methodology and results used by EPA in their calculations, the public cannot adequately comment on the area of review determination.

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[3] 42 U.S.C. § 300h(b)(1)(B).
[4] *Id*. at § 300h(d)(2).
[5] 40 C.F.R. § 144.3 (definition of underground source of drinking water (a)(2)(ii)).
[6] 40 C.F.R. § 124.7 (emphasis added).

Similarly, EPA provides a limit for the maximum injection pressure without describing the reasons that EPA believes that the maximum allowable surface injection pressure is appropriate. EPA merely states that it used the values presented by the Applicant in making its determination (without providing the actual values aside from specific gravity and well depth). EPA also states that "[t]hese pressure limitations will meet the regulatory criteria…," but does not state its reasons for that belief.

EPA should revise the Statement of Basis and the Supplemental Statement of Basis to include the derivation of its reservoir modeling input values and any other calculations that helped the agency determine the proper area of review and the maximum injection pressure since the agency apparently relies on that information to form the basis of its opinion that the maximum injection pressure will ensure that USDWs will not be endangered by the proposed injection due to seismicity.

II. EPA's Supplemental Statement of Basis Fails to Meet the Endangerment Standard.

The Need for Data on Rock Properties and Net Fluid Balance to Determine the Potential for Fault Failure

EPA should require that the Applicant provide scientific data to allow the agency to properly determine the potential for a seismic event due to the proposed injection activity. EPA did not require the Applicant to provide information on any of the recommended site assessment criteria developed by the EPA Underground Injection Control National Technical Workgroup in November 2012.[7] EPA should also follow its own draft guidance in the area of well operations, monitoring and management.[8] In addition, EPA should require the Applicant to evaluate and provide data on regional rock stress components, which would allow the agency to estimate the potential for fault failure due to localized injection zone pressure increases,[9] and net fluid balance as recommended by the National Academy of Sciences.[10] This would allow the agency to make an educated determination about seismicity before permit issuance *and* EPA could provide the required information in the statement of basis for public evaluation and comment.

Calculations of critical shear stresses and rock failure envelopes can be determined through the use of rock properties data gathered from whole cores taken from the injection zone during well drilling.[11] EPA should request that cores be gathered and petrophysical analyses performed. After subjecting that information to public notice and comment, EPA may determine whether the endangerment standard has been met.

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[7] EPA Draft on Minimizing and Managing Potential Impacts of Induced-Seismicity from Class II Disposal Wells: A Practical Approach, *available at* http://www.eenews.net/assets/2013/07/19/document_ew_01.pdf (last checked September 6, 2013).

[8] *Id.* at 30-33.

[9] Expert Report at 3-4 (Geology).

[10] National Academy of Sciences study, p.1.

[11] Expert Report at 4 (Geology).

In the Supplemental Statement of Basis, EPA states that injected wastewater "should be confined within the fault block as long as injection pressure is maintained below a critical stress, such as fracture pressure."[12] However, EPA has not told the public what it believes that critical stress and fracture pressure to be. According to Mr. Grant, these inputs are available to the Applicant and to EPA from published regional rock data.[13] Yet, EPA has not provided the public with any information about the inputs that it has used to determine the proper maximum injection pressure.

In fact, EPA uses the National Academy of Sciences' recent publication "Induced Seismicity Potential in Energy Technologies" to highlight only part of the findings of that study: that "very few events have been documented over the past several decades relative to the large number of disposal wells in operation."[14] However, the first part of that same sentence states that "[i]njection for disposal of wastewater derived from energy technologies into the subsurface does pose some risk for induced seismicity…."[15] The study also states that "[t]he factor that appears to have the most direct consequence in regard to induced seismicity is the net fluid balance (total balance of fluid introduced into or removed from the subsurface)…."[16] However, EPA does not bother to require the Applicant to determine the net fluid balance at issue here to allow a proper determination and proper public review under the endangerment standard.

In the Supplemental Statement of Basis, EPA routinely cites to the rarity of injection-induced seismic events. However, the endangerment standard requires that EPA account for that rare event and evaluate the site-specific conditions to determine whether the "injection *may* result in the presence in underground water which supplies."[17] In other words, EPA's statistics on the number of documented cases compared to the number of operating injection wells in the country has absolutely no bearing on whether EPA should issue the permit. Instead, EPA only needs to determine if an injection-induced seismic event *may* result in contamination of a USDW. According to Congress, any risk of contamination is too much when deciding whether to issue a UIC permit.

Transmissivity of the Fault

As EPA guidance makes clear, one of the reasons for pre-injection review of structural geology is that "under certain circumstances, subsurface fluid injection can stimulate movement along some faults … [and when] movement occurs, stored seismic energy is released as an

[12] Supplemental Statement of Basis at 2.
[13] Expert Report at 4 (Geology).
[14] Induced Seismicity Potential in Energy Technologies, National Academy Press (2013) at 1.
[15] *Id.*
[16] *Id.*
[17] 42 U.S.C. § 300h(d)(2).

earthquake."[18] Another reason for pre-injection review of structural geology is that cracks and joints (i.e., faults) can "channel fluids rapidly away from an injection well in a single direction or where they provide flow paths through confining strata."[19]

There are several ways in which EPA or an applicant can determine structural geology: (1) examination of rock cores obtained during drilling, (2) well logging and testing, and (3) prior experience with similar wells.[20] However, EPA does not provide data related to any of these possible ways of determining the geology and seismic risk related to injection from the Zelman #1 Well in either the original Statement of Basis or the Supplemental Statement of Basis.

EPA asserts in the Supplemental Statement of Basis that "there is no geologic evidence that [nearby] faults provide a mechanism for the transmission of formation fluids or that the other conditions necessary to cause seismic activity are present."[21] Unfortunately, EPA lacks geologic evidence because the Applicant failed to respond to the agency's Notice of Deficiency on the question of faulting in the injection zone and injection-induced earthquakes.[22] If the Applicant fails to provide required information, according to Congress' endangerment standard, EPA does not have the authority to issue the permit.[23]

While Applicant and EPA acknowledge the presence of a fault in the area of review, EPA does not look at the fault, even assuming that it is nontransmissive, as a mechanism to increase pressure in the reservoir.[24] EPA continues to have no direct evidence of the lateral and vertical sealing of the fault even though the Applicant has the ability to determine whether the fault is nontransmissive.[25] EPA uses the assertion of the nontransmissive nature of the fault as a reason that the injected wastewater will remain contained, but does not account for the increased pressure that will result due to a laterally-sealed fault within the injection zone. Thus, the Applicant has not met its burden to show that its proposed injection will not cause endangerment of USDWs.

EPA appears to claim in the Supplemental Statement of Basis that gas well production history in the area is evidence of the nontransmissive nature of the fault in the injection zone. However, EPA never shared the historical records that it relied upon in making this determination. While gas production data in the area was clearly used for surface-measured fracture breakdown pressure,[26] EPA has not described a link or a methodology that allows it to draw conclusions from that information and the nontransmissive nature of the fault in the

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[18] U.S. Environmental Protection Agency, Office of Drinking Water, *Final Injection Well Construction Practices & Technology* 11 (1982).
[19] *Final Injection Well Construction Practices* at 11.
[20] *Id*.
[21] Supplemental Statement of Basis at 2.
[22] Expert Report at 4.
[23] 42 U.S.C. §§ 300h(b)(1)(B), 300h(d)(2).
[24] Expert Report at 3-4.
[25] *Id*.
[26] *Id*. at 6.

injection zone. According to EPA's own rules, the administrative record is required to consist of "All documents cited in the statement of basis."[27] EPA did not provide such documents in the administrative record. Therefore, EPA should re-notice the draft permit and statement of basis with the gas well production documents cited in the statement of basis and re-open the comment period for a full 30 days.

As described in Mr. Grant's expert report, pressure increases occur in "laterally fault-defined reservoirs."[28] The type of basement faulting present at the site of the Youngstown, Ohio injection well that resulted in seismic activity there is the same type of faulting at issue here. According to Mr. Grant, EPA should use available regional rock stress data as inputs to determine the potential for fault failure due to the proposed injection activity.[29] EPA's draft permit allows the Applicant a maximum injection pressure that is equal to the fracture pressure of the rock.[30] Despite any operational testing required by EPA, Mr. Grant states that seismic activity could occur without warning due to the maximum injection pressure allowed by EPA.[31] Mr. Grant recommends that EPA require the Applicant fulfill its duty to prove that its injection activities will not cause endangerment of USDWs by providing whole core data from the Injection Zone during well drilling and petrophysical analyses.[32]

Maximum Injection Pressure Calculation and Operational Restrictions

EPA states that operating conditions, such as limits on the maximum injection pressure, constitute a mechanism to "minimize conduits for fluid to potentially contaminate" USDWs.[33] Yet, the proposed operating conditions and injection pressure limits (a sliding scale of injection pressures) are unworkable and inaccurate.[34]

Finally, EPA should set the maximum injection pressure with a margin of safety rather than at the equivalent of fracture pressure of the formation. Mr. Grant recommends a safety margin of "at least 100-200 psi" for the "maximum allowable bottom-hold (and surface) injection pressure."[35]

EPA contends that earthquakes are caused by the under-pressurization or over-pressurization of reservoirs within a geologic formation, that the Oriskany formation is currently under-pressurized due to decades of natural gas extraction and has not experienced any earthquakes to date, and that the proposed injection activities will not over-pressurize the

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[27] 40 C.F.R. § 124.9(b)(4).
[28] Expert Report at 3.
[29] *Id.* at 4.
[30] *Id.* at 3-4 (geology), 5-6 (formation testing program and stimulation program).
[31] *Id.* at 4.
[32] *Id.*
[33] Supplemental Statement of Basis at 2.
[34] Expert Report at 3-6 (Operating Data, Formation Testing Program, Stimulation Program, and Injection Procedures).
[35] *Id.* at 5.

Oriskany formation.[36] However, it is unhelpful to the decisionmaking process to suggest that the lack of earthquakes due to depressurization of the Oriskany gas reservoir is in and of itself proof of the lack of endangerment when there is no scientific evidence to suggest a correlation between that data.[37]

In addition, EPA should not simply consider the fracture gradient of the injection zone.[38] Instead, the agency should also incorporate fracture pressures of the adjacent overlying Onondaga Limestone.[39]

EPA makes general assertions without any support in the Supplemental Statement of Basis about the limits on rate and volume of injected wastewater reducing the potential for seismicity.[40] EPA fails to describe how the particular limits on the rate and volume of the fluid to be injected reduces the potential for seismicity. Mr. Grant reviewed the calculations provided by the Applicant and found serious oversights by EPA. Unfortunately, the Applicant's inputs and calculations of permeability, pressure increases over time, fracture gradient, reservoir surface pressure and maximum wellbore pressure are all drawn into question in Mr. Grant's review of the application, NODs and draft permit.[41]

For injection rate, the Applicant has used an incorrect formula that assumes a linear relationship between injection rate and pressure.[42] In addition, the characteristics of the wastewater to be disposed of appear to be unrepresentative of the fluid to be injected.[43] In addition, it is unclear that the Applicant used the correct permeability input because of repeated unit conversion problems.[44] And, again, EPA does not share the inputs that it used with the public. While EPA states that it "used instantaneous shut-in pressure from gas production wells located near the proposed Windfall well location as a basis to establish the maximum injection pressure for this permit,"[45] it does not share documentation of those pressures with the public.[46]

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[36] Supplemental Statement of Basis at 2.
[37] Expert Report at 3. Mr. Grant calls it "not particularly relevant."
[38] *Id*. at 6.
[39] *Id*.
[40] Supplemental Statement of Basis at 2-3.
[41] *See generally* Expert Report.
[42] Expert Report at 5 (Operating Data).
[43] *Id*.
[44] *Id*.
[45] Supplemental Statement of Basis at 3.
[46] Notably, at a public meeting held after issuance of UIC Permits PAS2D215BWAR and PAS2D216BWAR in the Bear Lake Properties, LLC, matter, Mr. Steve Platt stated that he was readily willing to send information such as calculations used in a modified Theis equation for determining the zone of endangerment. But later correspondence with Mr. Platt and EPA Assistant Regional Counsel Nina Rivera revealed that EPA was only willing to provide such information in response to a FOIA request rather than as part of the public notice and comment process. A video of the response by Mr. Platt is available at http://www.youtube.com/watch?v=u_Cie3q7cx4 (last checked September 10, 2013).

In the original Statement of Basis, EPA states that annual falloff testing will prevent seismic activity caused by the well. In the Supplemental Statement of Basis, EPA refers to an ultimate failsafe: a well design that automatically detects well integrity failures that causes the well to stop operating.[47] While it is somewhat heartening that the well would stop operating during a seismic event, EPA does not describe the risk of endangerment to USDWs in the area when the already-injected and stored wastewater is subjected to such conditions. In addition, it does not appear that EPA offered any changes to the permit to require such a design of the well. In fact, EPA's proposed tests, monitoring and injection procedures are "not operationally realistic" according to Mr. Grant.[48]

Far from instantaneous shut-in, the Applicant has proposed to observe injection pressure, rate and volumes only one time per week and recording those values only once per month.[49] EPA does not appear to offer any changes to the draft permit to facilitate a continuous monitoring and recording scheme for injection pressure, rate and volume in the Supplemental Statement of Basis. Merely requiring continuous monitoring of tubing and annulus pressures is far from sufficient when such a high level of risk is present from injection-induced seismicity in this region.[50] Even with continuous monitoring of the tubing and annulus pressures, EPA has not provided for minimum annulus and differential pressures to make its token monitoring program effective.[51] Mr. Grant identifies several other mechanical integrity issues with EPA's proposal.[52] Thus, there is little doubt that EPA's narrative description of the well design failsafe in the Supplemental Statement of Basis is an insufficient method to meet the endangerment standard.

III. Conclusion

EPA has not provided sufficient evidence to meet the endangerment standard. EPA should request a great deal of geologic information and calculations from the Applicant before the Safe Drinking Water Act would allow EPA to issue a permit. In addition, EPA must abide by its duty to include necessary information in its statement of basis to allow for meaningful public participation in the permitting process. After the Applicant provides sufficient information upon which EPA can craft a reasonably supported statement of basis for a draft permit, EPA should re-issue a draft permit and statement of basis for public review and comment for a 60-day period.

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[47] *Id.*
[48] Expert Report at 6.
[49] *Id.* at 7.
[50] *Id.* at 7-8.
[51] *Id.*
[52] *Id.* at 8.

Thank you for the opportunity to submit the above comments and for your consideration of them. Should you have any questions or concerns regarding any of the preceding, please do not hesitate to contact the University of Pittsburgh School of Law Environmental Law Clinic at (412) 648-1300.

Respectfully Submitted,

Emily A. Collins

Emily A. Collins, Esq.
Supervising Attorney

Exhibit 1

UIC Permit Technical Review
Windfall Oil & Gas #1 Zellman
Brady Township, Clearfield County, PA

Subject:
Draft UIC Permit PAS2D020BCLE
Windfall Oil and Gas Inc.
Zellman #1 Class II-D Injection Well
Clearfield County, Pennsylvania

Prepared for:
University of Pittsburgh School of Law
Environmental Law Clinic

Prepared by:
Philip R. Grant
Senior Geologist
Terra Dynamics Inc
Austin, TX

Date:
April 26, 2013

A review of the publically available documents related to the Windfall Oil and Gas #1 Zellman Class II-D injection well permit application and draft permit (PAS2D020BCLE) was performed at the request of the Environmental Law Clinic of the University of Pittsburgh School of Law. The following technical review and comments are based on that available information. Additional documents may be in the possession of the applicant or the USEPA which are not currently available for review, and which may address some of the issues raised in the following review.

The following technical review is divided into subject areas addressing various Attachments of the permit application, the USEPA Notice of Deficiency (NOD) letter, the applicant's responses to that NOD, the USEPA's Statement of Basis for issuance of the permit, and the USEPA's Draft UIC permit.

<u>AOR Calculation (Attachment A)</u>
The applicant uses a default ¼ mile radius AOR, and does not demonstrate why a larger AOR is not necessary, based on pressure increase calculations around the proposed well over the lifetime of the well. Based on the low permeability value presented for the injection zone (0.0061 mD,

later revised to 6.1 mD), there is a significant possibility that the AOR will encompass an area larger than the minimum ¼ mile radius during the life of the well.

The USEPA in its NOD requested that a calculation of the zone of endangering influence (ZEI) be provided to confirm the validity of using a minimum ¼ mile radius AOR. The agency also noted that the applicant's initially provided permeability of 0.0061 mD was too low, yet failed to note that the calculation of that value was incorrect due to the utilization of incorrect unit conversions for permeability. The agency suggestion that a value of 10-100 mD permeability value is more realistic provided no backup data for such a range.

The applicant in its NOD response noted the error in the permeability calculation; a revised value is 6.1 mD was given. However, the lack of an understanding of permeability unit conversions and realistic ranges puts into question the validity of the entire group of reservoir input values presented in the application. The applicant in its NOD responses also noted a current surface reservoir pressure of 90 psi, based on offset wells' gas gathering line pressures. If this value is the correct surface pressure, then the calculations of permeability in Attachment H and maximum wellbore pressure (Attachment I) use an incorrect reservoir surface pressure of 15 psig. These calculations should be revised to provide corrected determinations of permeability and maximum wellbore pressure. These revised values will in turn require the calculation of the ZEI to be redone.

The USEPA in its Statement of Basis notes that the agency calculated a zone of endangering influence (ZEI) using inputs provided by the applicant, and confirmed that a ¼ mile radius AOR was sufficient. However, the agency does not provide the methodology or results of their calculations. None of the USEPA calculations have been provided for public comment or review, which brings into question the independent nature of their review. The USEPA calculations needs to be made available for public review, to confirm that their inputs, methodology, and calculations are appropriate and valid.

<u>USDW (Attachment D and E)</u>
The applicant noted that the depth to salt water is estimated to be at around 1,000 feet, but assumes salt water aquifers to have total dissolved solids (TDS) values of 3,000 mg/L or greater. Their assertion that a USDW is 3,000 mg/L or less TDS is incorrect, as a USDW is defined as an aquifer with a TDS of less than 10,000 mg/L. If the applicant will be protecting to the base of the lowermost USDW as noted in the USEPA Statement of Basis, then they are to place and cement surface casing back to surface from that depth. The initially proposed surface casing depth is to 1,200 feet, which *may* protect the lowermost USDW. However, an actual demonstration (through log analysis or other accepted techniques) of the depth to the lowermost USDW has not been presented. Adjacent oil/gas wells' open hole electric logs could be used to

determine TDS values of the formation brines at these shallow depths, thus verifying the depth to the base of the lowermost USDW, by employing standard oilfield calculations of water resistivity using the Archie Equation.

The applicant in its NOD response provides a revised depth to the lowermost USDW of 797 feet, based on a local driller's log indicating that fresh water is present at a depth of 750 feet. If freshwater is still present at 750 feet, it is unlikely that the transition to salt water (>10,000 mg/L TDS) occurs within a vertical distance of 50 feet. Again, the applicant appears to be confusing usable quality water aquifers (<3,000 mg/L) with USDWs (<10,000 mg/L). Moving the base of the lowermost USDW upward from 1,000 feet to 797 feet is not as protective or justified.

The USEPA in its Statement of Basis appears to accept the applicant's designation of the USDW at 800 feet depth. The agency agrees that surface casing can be set to 1,000 feet and be protective of the lowermost USDW, whereas setting to a depth of 1,200 feet was initially proposed by the applicant. The Agency appears to be proposing less restrictive surface casing requirements that the applicant initially proposed.

Geology (Attachment G)

The fault shown intersecting the injection zone on maps in the application, with an offset of 397 feet and located to south of the proposed well and within the AOR, is noted to be both laterally and vertically sealing by the applicant. Yet no discussion is presented providing direct evidence of that statement. If laterally sealing, the ZEI and resulting COI should be re-calculated employing a pressure model with a no-flow boundary, as nearby lateral sealing faults result in higher reservoir pressures over time due to restricted lateral reservoir extent. The USEPA-proposed reservoir fall-off testing during well completion will help to both define any nearby lateral boundaries and natural reservoir fracturing, as well as determine the reservoir permeability.

The USEPA NODs bring up the issue of the faulting present in the injection zone within the AOR, and request that the issue of fault movement (earthquakes) due to injection be addressed, due to the heightened sensitivity of this issue in the Northeast. The applicant does not address how the lateral sealing faults affect injection pressures over time in their NOD response, or the potential for localized earthquakes related to injection. Instead they note that the Oriskany Formation (Injection Zone) has lateral sealing faults and an overlying sealing confining zone. The presence of faulting is not in dispute, but the pressure increases that occur within these laterally fault-defined reservoirs have not been resolved. The issue of faults as related to injection-induced earthquakes is also not addressed in anything but a broad cursory manner. The presented example of gas storage fields not producing earthquakes is not particularly relevant; the pressures generated by continued injection results in reservoir pressures significantly higher than those in gas storage fields where fluids are both injected and withdrawn and the reservoir pressures do not reach the levels present at commercial injection wells. The earthquake activity in neighboring Ohio and other parts of the country relates to injection wells that are used exclusively for wastewater disposal, not as ballast wells for gas storage fields. In the cases of these injection-induced earthquakes, basement faulting that extended upward into the Injection Zone (similar to those in the AOR) reached a pressure threshold great enough to allow critical shear stress failure on the fault planes. This scenario needs to be addressed in the application, as published regional rock stress components are available to input into estimations of fault failure due to localized Injection Zone pressure increases.

The USEPA does not further address the issue of laterally sealing faults and resulting pressure increases within the Injection Zone, even though the applicant in its NOD responses did not address the issue as requested. The Agency appears to contradict itself when it notes that the basement faults that are present within the AOR do not continue upward into the injection zone, but later states that based on gas production nearby, geologic faults exist within the Injection Zone which provide geologic traps for gas. In addition, the Agency rejects the possibility that earthquakes due to these basement faults could be induced by injection activities (a well-documented phenomenon) as well as by natural tectonic stresses.

The Agency in its Statement of Basis is requiring annual falloff testing as a method of assisting in the prevention of seismic (earthquake) activity related to the proposed injection well. While these tests provide a good indicator of reservoir pressure conditions, they do not in themselves assist in the warning or prevention of earthquake activity. The pressure test data can be used to track reservoir conditions, but the maximum injection pressure requested (discussed in the following section) is currently equal to the fracture pressure of the rock. Seismic activity could thus occur without any warning cues from the annual falloff test.

Calculations of critical shear stresses and rock failure envelopes can be determined through the use of rock properties data gathered from whole cores taken from the Injection Zone during well drilling. However, without site-specific petrophysical core lab analyses to determine tensile strengths, only a rough approximation of critical shear stresses can be made. It is suggested that the USEPA include in their permit requirements that such cores be gathered and such petrophysical analyses performed.

<u>Operating Data (Attachment H)</u>

The applicant provides information demonstrating a fracture gradient of 0.90 psi/ft, as evidenced from hydraulic fracturing performed in nearby wells completed in the Oriskany Formation. A USEPA letter confirms that value. The proposed maximum bottom-hole injection pressure of 6,575 psi is equal to this fracture gradient pressure of the rock at 7,306 feet depth. An additional nearby well's fracture gradients is also presented showing a gradient of 0.9518 psi/ft, which appears to include tubing friction loss. After just presenting data showing a fracture gradient of 0.90 psi/ft for the Oriskany Formation, it does not seem appropriate to then justify a higher fracture gradient exceeding the maximum bottom-hole injection pressure of the previously demonstrated fracture gradient.

Again, the applicant continues to confuse units of permeability in this Attachment. A calculated permeability is noted as .0061 millidarcies (mD), or 6.1 darcies. The unit conversion is reversed, as 6.1 millidarcies is equivalent to 0.0061 darcies. The applicant appears to not be conversant regarding reservoir characteristics and terminology.

The proposed maximum allowable injection rate of 2,296 bbls/day is calculated using inputs from another well whose location and formation characteristics are unknown. In addition, the assumption that the relationship between injection rate and pressure is linear (as used in their formula) is also suspect. As such, utilizing this formula does not appear to be appropriate.

The samples of the types of fluids to be injected provides analyses of four types of fluids proposed for disposal at the facility. One of these analyses (RMS # 4/11/13) shows a total dissolved solids (TDS) value of 341,000 mg/L. This may not be a representative oilfield brine sample from the Oriskany Formation as stated, as the maximum TDS value for normally saturated NaCl brines is 311,300 mg/L (equal to a specific gravity (S.G.) value of 1.2). As this sample has an undefined specific gravity value and appears to contain high levels of strontium, the source of the sample is suspect. As oilfield brines in this region may contain strontium levels of up to 100-200 mg/L, a reported level of 25,300 mg/L (over 100 times the typical maximum concentration value) either is due to a lab error or the reported Oriskany brine contains significant contaminants from some other unknown source. Of note, the EPA recommended maximum contaminant level (MCL) for strontium in finished municipal drinking water is 4 ppm (approximately 4 mg/L). The USEPA does not address the issue of the excessively high specific gravity request by the applicant, and the possibility that a maximum value of 1.26 may allow for the injection of fluids other than the requested reservoir brines from oil and gas production.

Formation Testing Program (Attachment I)

The requested maximum allowable bottom-hole injection pressure of 6,575 psi, as noted previously. This pressure is equivalent to the fracture pressure of the formation, as calculated by the applicant themselves. There is no reason that the maximum injection pressure should so closely approach the fracture pressure. A safety margin of at least 100-200 psi should be incorporated into the determination of the maximum allowable bottom-hole (and surface) injection pressure. In addition, it is impossible to accurately measure the maximum bottom-hole pressure using the proposed surface gauges. A more appropriate methodology would be to instead use a maximum surface injection pressure (applicant's proposed range is from 3,411 to 2,589 psi), calculated using only the maximum permitted specific gravity injectate and providing a safety margin of 100-200 psi. A sliding scale of injection pressures as proposed, based on varying injectate specific gravity values, is impractical and subject to significant calculation and lag time error. Of note, the adjacent # 327 well just outside of the AOR was intentionally fractured and had a surface measured fracture breakdown pressure of 2,400 psi in the Oriskany at the same depth as the proposed well's injection zone. This 2,400 psi fracture pressure value is 190 psi lower than the applicant's proposed low-end maximum injection pressure.

As discussed previously, the proposed maximum specific gravity of 1.26 is higher than a typical saturated NaCl brine (1.2 S.G.), which suggests that the proposed waste streams will consist at times of wastewaters from sources other than oilfield operations (see Attachment H discussion above). Also, the fracture gradient is noted in this Attachment as 0.95 psi/ft, whereas in other parts of the application a gradient of 0.9 psi/ft is documented and accepted from Oriskany Formation wells.

As no fracture gradients of the Confining Zone are presented, the argument that the Confining Zones provide confinement for regional gas storage is immaterial if the proposed injection well reaches subsurface pressures in the Oriskany Formation high enough to fracture the adjacent overlying onfining Onondago Limestone. Gas storage wells purposely hold injection pressures low enough so that no fracturing of their confining strata occurs, which would result in loss of valuable stored product.

Stimulation Program (Attachment J)

The applicant's proposed stimulation program is designed to fracture the Injection Zone, as sand is injected as a proppant into the stimulation-generated fractures. Thus the plan to limit the stimulation bottom-hole injection pressures to 6,480 psi so as to not exceed the proposed fracture pressure, to avoid fracturing the formation, is counter-intuitive. Based on the calculated permeability of 6.1 mD, it is very likely that this well will require such stimulation to be able to inject the quantities of fluid planned.

Injection Procedures (Attachment K)

The use of a variable maximum bottom-hole injection pressure, depending on the specific gravity of the injectate, cannot be accurately calculated in real time. The variables of tubing friction and injection rate in addition to specific gravity make any real-time calculation, where the injection pump's rate could be backed off so as to prevent exceeding the maximum bottom-hole pressure, not operationally realistic.

Construction Procedures (Attachment L)

The applicant's proposed cementing procedures to allow a wait of 12 hours before drilling out the casing shoe may not be appropriate. It is suggested that the drilling procedures be amended to increase the cement wait time to 24 hours for at least the shallow casing strings. Cementing of the long string casing back into the surface string casing at 1,200 feet, instead of only back to 5,000 feet depth, would be more protective of USDWs, and additionally isolate the long string casing from corrosion due to circulating brines present in shallower formations.

As noted earlier, the USEPA assumes the base of the lowermost USDW is at 800 feet depth, whereas there is no direct evidence for that depth presented in the application. In fact, the applicant states that the base of the lowest fresh water aquifer (3,000 mg/L or less) is estimated at a depth of 700-800 feet. If the intermediate 8 5/8-inch casing is placed at 850 feet instead of 1,200 feet, it would be less protective of usable quality waters (3,000 mg/L or less), and not protect the lowermost USDWs at all. It is suggested that the intermediate casing string should extend more than 50 feet below the 3,000 mg/L level, to at least 1,200 feet as originally proposed. The long string casing is proposed to be cemented up to 5,000 feet depth, so any lowermost USDWs present appears to not be protected below 800 (or 1,200) feet. It is suggested that the long string casing be cemented back up into the surface casing or to surface.

Preparedness and Contingency Plan (Attachment O)

The USEPA requested more information on site security. No additional information was provided by the applicant in its NOD responses. As site security is a major concern for most remote industrial facilities, the applicant's lack of additional detail is of concern. Vandalism or containment failure at remote injection well facilities when un-manned is a major concern to most commercial injection well operators, where surface spills would be potentially disastrous to surrounding land and water resources.

Monitoring Program (Attachment P)

The applicant's plan for observing injection pressure, rates, and volumes only one time per week, and recording these values only one time per month, is of insufficient frequency. Continuous monitoring and recording of these parameters is possible with the monitoring instrumentation proposed, and should be employed. Otherwise discursions from the permitted well parameter limits are unlikely to be identified unless occurring during the weekly observation event.

Although the tubing and annulus pressures are to be recorded continuously, the minimum annulus pressure and differential pressure from the tubing values are not demarcated. The USEPA does not define what is the minimum acceptable annulus pressure value to be continuously held is, or what differential pressure value between the annulus and tubing must be maintained. Without these values being defined, no valid monitoring of mechanical integrity can be assumed. These values should be defined and written into the permit operating conditions.

The applicant proposed that a mechanical integrity test (MIT) demonstration occur at 5-year intervals. A two-year testing schedule was then recommended by the USEPA in their Statement of Basis. However, the proposed mechanical integrity testing (employing an annulus pressure test) does not provide any evaluation of whether fluid movement is occurring into USDWs via upward movement outside of the production casing. Testing of that potential conduit which can lead to mechanical integrity failure are available and commonly employed as part of scheduled MIT testing of injection wells. A differential temperature survey or radioactive tracer test (using a low level dose of I-131 with an 8 day half-life) should be considered as an addition to the two-year annulus pressure test MIT requirement.

Plug and Abandonment Plan (Attachment Q)

The applicant's proposed plug and abandon plan procedures do not match the accompanying plugging schematic. Differences in casing recovery lengths and cement plug depths are evident. In addition, the plugging plan to employ sand plugs across the fresh water zones is not as protective as using a cement plug over the entire length of these aquifers. The USEPA suggests gel spacers between the cement plugs, but mud plugs would likely be a better option, and a full cement plug from bottom to top would be most protective. It is suggested that, to be the most protective of the shallow aquifers, the borehole be filled from bottom to top with cement after the 4 ½-inch casing is shot off and partially retrieved.

The USEPA accepts the plugging methodology and cost. However, the plugging methodology is not adequately protective of USDWs, and the plugging costs are understated. The subcontractor and applicant cost estimates to plug the well are outdated, and appear to be significantly underestimated. As these costs directly relate to the financial assurance demonstration, these values need to be revised.

Standby Trust Agreement (Attachment R)

The standby trust agreement needs to be updated to reflect more realistic plugging and abandonment costs.

Technical Review Conclusions

The discussions and documentation included in the permit application, the USEPA NODs, the applicant's responses to the NODs, the USEPA Statement of Basis, and the USEPA draft permit do not adequately address the issues raised in this technical review. Until these issues are addressed in a satisfactory and complete manner, it would be prudent for the USEPA to reconsider the issuance of the final UIC permit for the proposed Windfall Oil & Gas #1 Zellman Class II-D injection well.