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.

<u>Geology (Attachment G)</u>
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.

Operating Data (Attachment H)

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.