UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION III
1650 Arch Street
Philadelphia, Pennsylvania 19103-2029

Response to Comments
for
The Issuance of an Underground Injection Control (UIC) Permit
for
Windfall Oil and Gas, Inc.

On November 7, 2012, the U.S. Environmental Protection Agency Region III (EPA) issued a public notice requesting comment and announcing the opportunity for a public hearing for the proposed issuance of an Underground Injection Control (UIC) permit, PAS2D020BCLE, to Windfall Oil and Gas, Inc. (Windfall) for one Class II-D well. EPA received numerous requests to hold this hearing and it was held on December 10, 2012, at the Brady Township Community Center in Luthersburg, Pennsylvania. Over 250 people attended this public hearing and EPA received oral comments from about 29 people in attendance at the hearing. At the conclusion of the public hearing, EPA extended the public comment period until December 31, 2012, and invited the submission of any additional written comments. In total, EPA received approximately 2600 comments. During the public comment period, all the information submitted by the applicant was available for review at the Dubois Public Library and at the EPA regional office.

Comments submitted during the public comment period which ended December 31, 2012, raised substantial questions related to seismicity concerns about the proposed well. Pursuant to 40 C.F.R. §124.14(b), the Region reopened the public comment period on this draft permit. On August 11, 2013, the Region issued a public notice and requested additional public comment on its proposed findings that the well, as permitted, is unlikely to pose a risk of induced seismicity and why any potential earthquakes would not pose a risk to the construction and operation of the injection well. The reopening of the public comment period was limited to these two issues and closed on September 11, 2013.

The Region issued an initial final permit authorizing injection at this well on February 4, 2014. That permit was appealed by multiple parties to the Environmental Appeals Board. In response to the appeals, the Region sought a voluntary remand to further consider the comments submitted by the public. The Board granted the remand on June 10, 2014. After further consideration of the comments and issues raised by the public, the Region has decided to issue the final permit, authorizing construction of and injection into the Windfall well.

The response to comments which follows consolidates and provides responses to questions and issues raised by people who either sent timely written public comment during the initial public comment period, sent timely written comments on the issues related to seismicity during the reopening of the comment period, or who provided comments at the hearing. EPA wishes to thank the public for their informative and thoughtful comments and to thank the people from the Brady Township Community Center that assisted EPA in hosting the public hearing.

1) What does EPA's UIC program have jurisdiction and authority to regulate?

Many people raised concerns about matters that the EPA UIC program does not have the regulatory jurisdictional authority to address in the UIC permitting process. Some of the concerns mentioned were the potential for increased truck traffic, the potential for damage to the roads, increased noise, the proposed location of the injection well in a residential area, the potential for the diminishment of property values and the possibility of surface spills. When making the decision on whether to issue a UIC permit for Windfall, EPA's jurisdiction rests solely in determining whether the proposed injection operation will safely protect underground sources of drinking water (USDWs) (i.e., aquifers supplying any public water system or containing a sufficient quantity of ground water to supply a public water system and containing less than 10,000 milligrams per liter total dissolved solids) from the subsurface emplacement of fluids. Although the concerns raised may be relevant to residents, they cannot be addressed through the EPA UIC permitting process. Other local, county, state or federal ordinances or regulations may address traffic, road noise, zoning concerns, and surface spill prevention. The permit application did include the facility's preparedness, prevention and contingency plan which documents measures that Windfall will take to prevent and control surface spills, such as pressure valves to prevent spills and secondary containment.

EPA notes that the final UIC permit contains several conditions that require the permittee to meet all other local, state or federal laws that are in place. Part I.A. of the permit contains a clause that states, "Issuance of this permit does not convey property rights or mineral rights of any sort or any exclusive privilege; nor does it authorize any injury to persons or property, an invasion of other property rights or any infringement of state or local law or regulations." In addition, Part I.D.12 of the permit states, "Nothing in this permit shall be construed to preclude the institution of any legal action or relieve the permittee from any responsibilities, liabilities, or penalties established pursuant to any applicable state law or regulation." Therefore, EPA's UIC permit is only one of several authorizations that a permittee may be required to obtain before it is allowed to commence construction and/or operation.

2) Do the UIC regulations supersede local land use plans?

Brady Township joined with five other municipalities in Clearfield County to develop the "Northwest Clearfield County Regional Comprehensive Plan" in 2009. This document is a plan for future growth and describes areas of compatible use within the municipalities with respect to residential, commercial and retail development. As mentioned in response number (1), EPA requirements do not supersede local, county or state law or regulations. If state or local law requires Windfall's injection operations to comply with the Comprehensive Plan, the UIC permit would not abrogate those requirements.

3) EPA should require the operator to find another location for disposal.

As stated in the responses to the previous two questions, EPA does not have the jurisdictional authority to require operators to construct their injection well disposal facility in a particular geographic location. The location chosen by an operator is based on many factors: economics, property ownership and accessibility, geologic suitability, etc. It is EPA's statutory and regulatory responsibility to review each UIC permit application it receives and make a determination as to whether USDWs will be protected from the proposed operation. Likewise, EPA cannot deny a permit solely because of residents' opposition to the location, if the applicant otherwise meets the requirements of the UIC program.

4) The information in the application is not trustworthy because there are discrepancies between the information submitted by Windfall in the UIC application and the PADEP application for drilling a new well.

In addition to obtaining a permit from EPA authorizing underground injection, Windfall will need to obtain a drilling permit from Pennsylvania's Department of Environmental Protection (PADEP) to construct this new well. Any construction and operating permit issued by PADEP typically duplicates EPA's permit, since EPA is the agency having jurisdiction over the implementation of the UIC program in Pennsylvania. Windfall's UIC permit application includes a well location plat form submitted to PADEP on the proposed well.

A few commenters indicated that there are discrepancies between information submitted by Windfall in its UIC permit application and the information it submitted to PADEP. Commenters pointed to discrepancies in the latitude and longitude coordinates for the well, and in the ultimate depth of the well, in the documents submitted to the state and EPA.

The difference in the coordinates arises from the rounding up of the coordinates in the UIC application to fit the information in the space provided on the application form. The final permit identifies the well in the same coordinates as in the location plat submitted to PADEP, and the area of review around the well is defined by a radius from that specified location.

Any discrepancy with respect to the drilling depth exists in the application materials because the Windfall well has not yet been drilled. The exact depth of the Windfall well will be determined once the well is drilled. Note that the wording in the EPA permit provides approximate depths, because until the well is drilled, it is not appropriate to specify exact depths. Similarly the PADEP document only states the "anticipated" depth of the well. Ultimately, the permit limits injection to the Huntersville Chert/Oriskany formation.

5) A topographic map of one mile around the proposed well location was not provided by the applicant as required by the regulations.

The UIC regulations and the permit application require the submission of a topographic map extending one mile beyond the property boundary, showing the location of the injection well or project area for which the permit is sought. The applicant provided the map described above in Attachment O of the application and provided a more detailed map of higher resolution, of the area of review in Attachment C. This detailed map was titled, "Proposed Disposal/Injection Well for Windfall Oil and Gas" and was developed by Alexander & Associates.

The one-mile map must show all intake and discharge structures; all hazardous waste treatment, storage, or disposal facilities; and all injection wells. Besides the proposed Windfall well, none of these structures or facilities were found in this one-mile area. In addition the map must show all drinking water wells, springs and surface waters within a quarter-mile of the property boundary. These were depicted in the Alexander & Associates map.

In deciding whether to issue a UIC permit, the Region needs to consider a map of the area of review (a quarter-mile radius in this case) showing the following: the number, or name, and location of all existing producing wells, injection wells, abandoned wells, dry holes, surface water bodies, springs, mines (surface and subsurface), quarries and other pertinent surface features including residences and roads, and faults, if known or suspected. These were depicted in the Alexander & Associates map.

Both the one-mile radius map and the higher resolution map of the area of review were available for review with the permit application in both the Dubois Public Library and at the EPA Region III Office.

6) The construction parameters for the injection well are not protective of underground sources of drinking water.

A provision of the UIC regulations, 40 C.F.R. Section 147.1955(b)(1), requires an injection well's surface casing to be placed 50 feet below the determined lowermost USDW. Windfall identified the lowermost USDW where the injection well will be located at a depth of approximately 800 feet, based on historical drilling logging records.

A commenter suggested that open-hole electric logs should be used to determine the Total Dissolved Solids (TDS) content of water-bearing formations at the proposed well site. Water-bearing formations with less than 10,000 mg/l TDS could qualify as USDWs. However, the regulations do not require open-hole electric logs for a Class II permit application, and the information provided by Windfall is consistent with the geology of Pennsylvania, where water-bearing formations that meet the definition of a USDW are limited generally to within 500 feet below the land's surface but can be as deep as 800 to 1000 feet below land surface. Generally below 700-1000 feet deep, Pennsylvania geology does not provide for aquifer systems that would be categorized as USDWs. Geologic formations at these depths are generally tight shale and limestone formations, which do not typically bear water. The tight shale and limestone formations can be followed by deeper oil and gas bearing formations, which may bear water, but which have high levels of total dissolved solids. Drilling records of nearby production wells submitted with the application, as well as gamma ray logs, confirm that drillers were not finding water that would qualify as a USDW below 800 feet.

The permit will require surface casing to be placed to a depth of 1000 feet and be cemented back to the surface. This exceeds the requirements of the UIC regulations at 40 C.F.R. Section 147.1955(b)(1). If surface casing were to be placed any deeper the drilling process could interfere with deeper formations capable of producing natural gas which could affect the cementing of the casing as well as potentially cause the migration of shallow gas upwards into USDWs. This depth also satisfies PADEP requirements.

In addition, because most residents obtain their drinking water from much shallower aquifers through private wells, the permit will also require the injection well owner to install two additional water protective strings of casing, one to a depth of 170 feet and the other to a depth of 375 feet. The depths of these additional water protective casing strings are based on the depth of nearby drinking water wells. Both of these protective strings of casing will be cemented back to the surface. Windfall will also be required to obtain a drilling permit from PADEP and meet any additional well construction requirements that State regulations require under Act 13.

Some commenters were concerned that the drilling of the injection well could affect their drinking water. These commenters stated that maintenance work in a nearby gas well would affect water pressure from their water well and increase the turbidity of their water. The drilling of a well could initially increase water turbidity and affect water pressure. When this does occur, the effects are usually temporary and cease once water protection casing strings have been set and cemented. In addition, this happens more frequently when deep well drilling occurs without the installation of casing that protects shallow ground water. In this case, the workplan for the construction of the injection well minimizes the impact on USDWs during construction, through the installation of the two additional water protection casing strings, and the cementing of each of these casing strings before proceeding to drill the injection well deeper. This prioritizes the isolation of the USDWs during the construction process to prevent pressure loss and turbidity concerns.

After the injection well is drilled and the well casings are installed and cemented, and before the injection operations commence, the operator must submit a completion report to EPA that will provide details regarding the drilling, completion and testing of the well including the well's drilling records, logging information, cementing records and mechanical integrity testing information. From this information, EPA can verify the geological information submitted in the permit application about the formation in the proposed location, and the proper cementing and construction of the injection well, to assure that the injection well will not leak during operation or allow fluid movement out of the injection zone via the injection wellbore. The review of cementing logs to verify proper cementing will assure that there are no voids between the casing and the well bore that could provide a conduit for fluid movement. The mechanical integrity test will verify that there are no internal failures in the tubing, casing or packer installed within the well. If new information obtained from the completion report warrants changes to the permit, EPA can modify the permit conditions.

7) The long string casing should be cemented back to the surface.

Windfall's proposed well construction plan calls for the circulation of cement behind the long string casing to approximately 2300 feet above the well's total depth. The cement placed behind the long string casing is designed to seal and isolate the well to prevent fluid movement out of the injection formation. Windfall's proposed well construction meets EPA's regulatory requirements for Class II wells in Pennsylvania, found in the UIC regulations at 40 C.F.R. §147.1955(b)(5), which were adopted to prevent endangerment of the USDWs.

8) The proposed injection well is located close to several geologic faults and this could cause fluid migration and seismic activity.

Although EPA must consider appropriate geological data on the injection and confining zone when permitting Class II wells, the SDWA regulations for Class II wells do not require specific consideration of seismicity, unlike the SDWA regulations for Class I wells used for the injection of hazardous waste. See regulations for Class I hazardous waste injection wells at 40 C.F.R. §§ 146.62(b)(1) and 146.68(f). Nevertheless, EPA evaluated factors relevant to seismic activity such as the existence of any known faults and/or fractures and any history of, or potential for, seismic events in the area of the injection well as discussed below and addressed more fully in *"Region 3 framework for evaluating seismic potential associated with UIC Class II permits, updated September, 2013."*

One commenter cited a draft EPA report that looks at injection-induced seismicity ("Minimizing and Managing Potential Impacts of Induced-Seismicity from Class II Disposal Wells: A Practical Approach," EPA UIC National Technical Workgroup, draft as of November 27, 2012[1]) and suggested that EPA follow the recommendations in the draft report. The cited draft report is an initial draft that is currently going through a peer review process, and thus the Agency is not ready to finalize any recommendations based on the report. Nonetheless, in issuing this permit EPA followed some of the suggested recommendations in the draft report, as they constitute good permit issuance practices. These include: assess regional and local seismicity; correlate any area seismicity with past injection practices; evaluate geological information to assess the likelihood to activate faults; evaluate storage capacity of the formation with consideration of porosity and permeability; include operational parameters to limit injection rate and volume and to limit operation at below fracture pressure; and require frequent (continuous in this case) monitoring of injection pressure and rates.

Induced seismicity background

Under certain conditions, disposal of fluids through injection wells has the potential to trigger seismicity. However, induced seismicity associated with brine injection is uncommon, as conditions necessary to trigger seismicity often are not present. Seismic activity induced by Class II wells is likely to occur only where all of the following conditions are present: (1) there is a fault in a near-failure state of stress; (2) the fluid injected has a path of communication to the fault; and (3) the pressure exerted by the fluid is high enough and lasts long enough to allow movement along the fault line. Induced Seismicity Potential in Energy Technologies, National Academy Press, 2013, at p. 10-11. Although there are approximately 30,000 Class II-D wastewater disposal wells operating in the United States, only a few of these wells have been documented to have triggered earthquakes of any significance and none of these earthquakes, which EPA Region III is aware of, have ever caused injected fluids to flow into or contaminate a USDW.

The presence of a fault in a receiving formation potentially creates a more vulnerable

[1] The EPA UIC Technical Workgroup has continued its work on this report. The draft cited by the commenter may not be the most recent report under review at EPA Headquarters.

condition for a future seismic event. A fault is a fracture or a crack in the rocks that make up the Earth's crust, along which displacement has occurred. Where a fault is present near an injection site, scientists believe that injection can trigger seismicity when the pore pressure (pressure of fluid in the pores of the subsurface rocks) in the formation increases to such levels as to overcome the frictional force that keeps the fault stable. Pore pressure increases with increases in the volume and rate of injected fluid. Thus, the probability of triggering a significant seismic event due to injection, where the injection fluid reaches an active fault, increases with the volume and the rate of fluid injected. In addition, the larger the volume injected over time, the more likely a fault could be intersected, because the fluid will travel farther within a formation. When injected fluid reaches a fault, frictional forces that have been maintained within that fault can be reduced by the fluid. At high enough pore pressure, the reduction in frictional forces can result in the formation shifting along the fault line, resulting in a seismic event.

Because increases in pore pressure due to the rate and the volume of injected fluid can act on existing faults and provide a mechanism for induced seismicity, most examples of injection-induced seismicity are in cases where the receiving formation has low permeability and/or the pressure or volume of fluid injected over time is quite large. Formations such as crystalline basement rock (deeper geological formations of igneous or metamorphic rock that underlie layers of sedimentary rock) have very low permeability. Permeability is the ease with which a fluid can flow through the pores in a rock layer. Where permeability is low, injected fluid cannot flow easily through the pores in this rock and therefore flow is oriented mainly through existing fractures or faults in the rock (secondary permeability). These kinds of rock formations have high transmissivity and low storativity. This means that the formation cannot store a lot of fluid; rather fluid moves farther and faster in these formations than in more porous formations. Because of the high transmissivity and low storativity of these kinds of rocks, the potential exists to induce pore pressure increases at considerable distances away from the injection well.

Faults near the proposed well

The applicant submitted, and EPA obtained, geological information indicating the possible presence of several faults within one-quarter mile of the injection well site, in the receiving formation. These faults appear to be localized, non-transmissive faults[2] and provide the structural confinement which enabled natural gas to be produced from this area since the 1950s. There is no geologic evidence that indicates that these faults extend to the deep Precambrian crystalline basement rock, where geologic information indicates other faults also exist. In this location, Precambrian basement rock is approximately 11,000 feet below the proposed injection zone.

Geologists also know that the faults in the Oriskany/Huntersville Chert do not extend to the surface. This can be seen by reviewing well drilling logs which do not show displacement caused by these faults extending upward. The presence of these faults has been inferred from

[2] Transmissive faults allow fluids to move along the fault and between formations. Non-transmissive faults, in contrast, act like a barrier, which would prevent movement of fluid along the fault and into another formation across the fault. Because not all faults act as a channel to conduct fluids, but rather as barriers, the UIC Class II requirements focus not on all faults but rather on *open* faults. *See* 40 C.F.R. § 146.22(a)("zone that is free of open faults.") (emphasis added)

drilling records and geologic cross sections showing displacement of the bedrock. The presence of the fault to the south of the proposed well in the Oriskany/Huntersville Chert is confirmed by drilling records included in the application.[3]

The United States Geological Survey (USGS) tracks, records and maps faults and earthquake epicenters in certain areas throughout the United States. The USGS monitors several active seismometers right in Clearfield County, in the vicinity of the proposed well. The USGS as well as the Pennsylvania Department of Conservation and Natural Resources (PA DCNR) which includes the Bureau of Topographic and Geologic Survey, the principal organization that conducts geologic research in Pennsylvania, have not recorded any seismic activity that has originated in Clearfield County.

USGS has recorded seismic events in Clearfield County although such events are extremely rare. Earthquakes that have been recorded, as well as felt in the area, were the result of seismic events that had their origins in other parts of the state or outside of the state's borders. The County is not located in a seismically active area and although there are several sub-surface geologic faults located within one-quarter mile of the injection well site, their presence in the area is due to tectonic activity that occurred many millions of years ago. Please refer to the PA DCNR website which has an interactive seismicity map and catalog of all recorded seismic events in or near Pennsylvania from 1724-present.

During an earthquake, energy is radiated away from the hypocenter of the fault in the form of seismic waves. This energy causes the ground to move as the seismic waves travel away from the fault. What have been felt in the County are seismic waves that were transmitted through the bedrock from the hypocenter of a seismic event that originated somewhere else. Seismic events which originate elsewhere do not provide information about the geology of Clearfield County, even if these events were felt there. The distance that the seismic waves travel is not indicative of the extent of the fault where displacement occurred due to the earthquake. Although seismic waves can cause the ground to shake a large distance away from the hypocenter of the earthquake, the fault where displacement occurred does not extend everywhere where the earthquake was felt. For this reason, history of seismicity that originates in areas other than the location of the injection well does not provide information about potential faults or formation pressures at the location of the well. For example, in the case of the Northstar 1 injection well in Youngstown, Ohio, the earthquake is believed to have been generated by injection into Precambrian crystalline bedrock, a deeper receiving formation, with different geology, than what is proposed for the Windfall well. The seismic waves radiating away from this area were felt in locations at significant distances away from Youngstown, including western Pennsylvania, but they have no relevancy to the geologic setting in Clearfield County or at the Windfall location.

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[3] Several commenters also mentioned synclinal and anticlinal features in the geology of the area of the proposed well. Synclines and anticlines refer to folds in geological layers and can be expressed at the surface as hills and valleys. These synclines and anticlines also occur in the subsurface but they have no bearing on the faults discussed within this section.

Factors affecting fluid transmission and pore pressure

The Windfall permit has been developed to prevent the over-pressurization of the injection formation by limiting the surface injection pressure during the injection operations to 2443 psi and the bottom-hole injection pressure to 6425 psi. Research indicates that continuous very high rate of injection or over-pressurization of a geologic formation can contribute to the possibility of seismic activity. The permit limits for the surface injection pressure and the bottom-hole injection pressure were calculated to ensure that, during operation, the injection will not propagate existing fractures or create new fractures in the formation. Limiting the pressure not only prevents the propagation of fractures that could become potential channels for fluid movement into USDWs but that could also serve as conduits for fluids to travel from the injection zone to known or unknown faults.

The Windfall permit will also require a yearly pressure fall-off test. As part of the test, the rate of fluid and volume injected is increased over a predetermined time period, and then shut off. The pressure is monitored during the test and after shutting-in the injection well. The fall-off testing will assist EPA in determining and monitoring injection reservoir bottom-hole pressure as well as the flow conditions that the injection formation will exhibit during the injection operation. Analyzing flow conditions can help determine whether a preferential flow pattern exists and assist in determining whether that flow could be moving toward or coming into contact with the nearby faults.

A significant volume of gas and brine has already been removed from the proposed injection reservoir, during previous gas production operations, making the Huntersville Chert/Oriskany formation receptive for the disposal of fluid. The Huntersville Chert/Oriskany formation, the intended injection zone, has been a prolific producer of natural gas in this area since the late 1950s/early 1960s, and state geologists believe that the accumulation of gas is related to the fault system in the Oriskany, as migration of gas is not observed between fault zones. There are still a number of active gas production wells in this area drilled into this formation. Evidence from gas production records from the PA DEP Office of Oil and Gas Management, Oil and Gas Reporting Website, which is a public website located at www.paoilandgasreporting.state.pa.us, indicates that gas production wells located within the fault structure where the injection well has been proposed, have produced significantly greater volumes of natural gas and produced water than gas production wells located outside of this fault structure. For example, gas production well #20333, located between the faults based on drilling records, produced approximately 612,992,000 million cubic feet (Mmcf) of natural gas and 67,115 barrels of brine during a period from 1980 through 2011. This well was drilled in 1960, so there is another, additional, twenty years of production history for this well that has not been recorded. In addition, gas production well #20327 was also drilled in 1960 and is also located within the fault structure based on drilling records. Although the production record for this well is also incomplete, available records indicate that it has produced at least 71,613 Mmcf of natural gas since 1983. The removal of these fluids has not resulted in any seismic activity nor have the presence of the faults allowed fluids to move out of the formation and into USDWs. The removal of both natural gas and brine from the natural pore spaces that exist in a formation lowers the formation's pore pressure (reservoir pressure) and creates available storage capacity making reservoirs with a history of gas and oil production good candidates for the disposal of fluids. The National Academy of Sciences Report entitled Induced Seismicity Potential in Energy Technologies (2013) indicates that where fluids are injected into sites such as depleted oil, gas or geothermal reservoirs, these reservoirs can make excellent disposal zones, because in those cases, pore pressures may not reach their original levels, or in some cases, may not increase at all due to the relatives volumes of injection versus extracted fluid.

Other gas production wells drilled outside the fault block in which the Windfall well is located were plugged for lack of production. For example gas production well #20325, was documented as a dry hole and was actually plugged and abandoned in 1960 shortly after completion. This gas well production history helps to illustrate that the displacement of the Huntersville Chert/Oriskany formation created by the faults established confinement of natural gas and formation fluids within the immediate fault block structure and that fluid flow (natural gas and produced water) along or across the faults is not evident. Because of the non-transmissive nature of the faults, fluid that is injected into the Huntersville Chert/Oriskany formation at the proposed injection well location should be confined within the fault block.

One commenter argues that little brine has been removed from the receiving formation during gas production and that therefore there is not much pore space for the injected fluid. Ultimately, the storage capacity of a receiving formation will be determined by the injection well's operating pressure. This particular injection well is limited by the maximum injection pressure established in the permit for the well. See Part III.B.4 of the permit. Therefore, if pressure buildup occurs quickly during operation, an indication of limited storage capacity, the operation of the injection well will be limited by the established maximum injection pressure. As pore space capacity to assimilate injected fluids decreases, the pressure needed to inject fluids will need to increase. Under the operating parameters of the permit, if such pressure reaches the maximum injection pressure, injection cannot proceed (regardless of whether the well has been operating one year or 30). So, even if the commenter is correct, that the storage capacity of the receiving formation is limited, the result would be that the life of the well would be shorter than for a well with a receiving formation of greater storage capacity.

The public brought to EPA's attention recent seismic events that have occurred in Ohio, Texas, Oklahoma, West Virginia and Arkansas that were attributed to the underground injection of fluids produced from oil and gas extraction activities. EPA recognizes that there is strong evidence that supports the underground injection of fluids as being the trigger that led to these seismic events. In some cases, these earthquakes occurred in locations were there were no known faults. However, the likely relevant factors behind these seismic events, specifically the geologic setting or the operational history of the injection wells, differ significantly from the proposed Windfall injection operation. As stated above, scientific evidence indicates that seismic activity is most likely associated a fault being in a near-failure state of stress, fluid having a path of communication to the fault and the volume and rate of injection is high and lasts for a long time. In these aspects the Windfall well contrasts greatly with the wells in the known cases of induced-seismicity.

The "Preliminary Report on the Northstar1 Class II Injection Well and the Seismic Events in Youngstown, Ohio Area, Ohio Department of Natural Resources, March 2012", has indicated that the seismic activity associated with the injection of fluid in the Northstar 1 was likely due to the injected fluid coming into contact with a fault system located in deep Precambrian basement crystalline bedrock. This bedrock is located beneath the sedimentary bedrock structure and has very low permeability. Fluid injected in crystalline basement rocks is essentially transmitted by a network of inter-connected fractures and joints. Because of the high transmissivity (the ability of fluids to move through rock) and minimal ability to store fluids in these kinds of rocks, the potential exists to create flow at considerable distances from the injection well. Once flow reaches a fault, it allows the frictional forces that exist to be reduced thereby allowing the rocks to slip, leading to seismic activity. In contrast, the injection zone for the Windfall injection well is the Huntersville Chert/Oriskany formation, a sedimentary rock formation of Lower Devonian age, which has a higher natural porosity and greater interconnection of that pore space throughout the formation than the crystalline bedrock. The Huntersville Chert/Oriskany formation is located at a depth of approximately 7300 feet below land surface (approximately 5600 feet below sea level) at the proposed injection well site. The Precambrian crystalline basement rock in the area of the proposed injection well is located approximately 16,500 feet below sea level, a significant depth below the Huntersville Chert/Oriskany formation (Pennsylvania Geologic Survey – General Geology Open File Report 05-01.0). In the Huntersville Chert/Oriskany formation the rock will more readily store injected fluid and the permeability (the available interconnected space between the grains and natural fractures in the rock) within the rock structure will allow a more uniform flow to occur throughout the formation. So, the geologic setting and reservoir characteristics of the proposed injection well are very different than the circumstances encountered in Ohio. Injection will not occur or flow into the deeper Precambrian crystalline rocks.

Regarding the seismic event in Texas, a study out of the University of Texas at Austin's Institute for Geophysics (Proceedings of the National Academy of Sciences, August, 2012) has indicated the seismic activity was likely triggered by the significant volume of fluid that was injected in a relatively short period of time. Approximately 150,000 barrels of fluid per month had been injected down a disposal well since 2006. This equals approximately 75,600,000 gallons of injected fluid, yearly, for about a five year period. The proposed Windfall injection well will be limited to a maximum of 30,000 barrels per month, one-fifth the total of the Texas well. Researchers studying the circumstances that led to the seismic events in both Oklahoma and Arkansas believe that over-pressurization of a nearby fault after years of injection may have led to the seismicity. Similar to what happened in Ohio, injected fluid migrated into Precambrian rocks, which in the case of those wells were found just below the injection zone, and came into contact with a fault ("Science", Volume 335, March 23, 2012). It is believed that the reduction of the frictional stress in the faults led to slippage along the faults (From the journal "Geology", co-authored by researchers with USGS and Oklahoma Geologic Survey, March 3, 2013).

In Braxton, WV, there is no definitive evidence, unlike the evidence produced for Youngstown, OH, that concludes injection was responsible for the seismicity in the area. However, information obtained from the West Virginia Department of Environmental Protection seems to indicate that when the injection rate, and later the injection volume, were reduced in the injection well, seismic activity in the area ceased. The geology where this injection well was completed is also different from the geology of the proposed Windfall injection well. The injection well in West Virginia is drilled into the Marcellus Shale, which has low permeability.

The last recorded seismic event in the Braxton, WV area was recorded in January, 2012; the injection well that was suspected of causing the seismicity continues to operate.

9) Endangerment of USDWs due to earthquakes

Of the hundreds of thousands of injection wells operating in the United States, EPA is not aware of any case where a seismic event caused an injection well to contaminate an USDW. An inquiry through EPA regional offices did not reveal any reports of earthquakes having affected the integrity of injection wells in the cases of induced-seismicity in Ohio, Texas, Oklahoma, West Virginia or Arkansas. A number of factors help to prevent injection wells from failing in a seismic event and contributing to the contamination of an USDW. Most deep injection wells, those that are classified as Class I or Class II injection wells, are constructed to withstand significant amounts of pressure. They are typically constructed with multiple steel strings of casing that are cemented in place. The casing in these wells is designed to withstand both significant internal and external pressure. The American Petroleum Institute (API) (see www.api.org) and oil and gas service companies such as Halliburton Services (see Halliburton Cementing Tables, 1980), have developed industry standards for casing and cementing wells. Furthermore, brine disposal injection wells are required to be mechanically tested to ensure integrity before they are operated and many are continuously monitored after testing to ensure that mechanical integrity is maintained. If a seismic event were to occur that affected the operation and mechanical integrity of the Windfall injection well, the well will be designed to automatically detect a failure due to pressure changes in the well and this would cause the well to automatically stop injection. See Part II.C.2 of the Permit.

10) There are no other injection wells in Clearfield County so EPA has no way of knowing that fluids can be safely injected into the Huntersville Chert/Oriskany formation.

Several comments mentioned that since no other brine disposal injection wells exist in Clearfield County, EPA has no basis of knowing that the injection of fluids into the Huntersville Chert/Oriskany formation will work. Two Class II-D brine disposal injection wells permitted by EPA Region III are currently injecting produced fluid from oil and gas operations in Clearfield County. Both wells are currently operated by EXCO Resources. One injection well has been operating since 2005 and has injected approximately 623,405 barrels of produced fluid into the Huntersville Chert/Oriskany formation. The other well has been operating since 1989 and has injected approximately 371,481 barrels of produced fluid into a shallower formation known as the Tiona Sandstone. Both totals are based on annual reports submitted by the permittee through 2012. During this period of operation injection pressures continue to remain below the maximum injection pressures permitted indicating each injection zone has been able to accept these volumes of fluids efficiently without exceeding reservoir fracture pressure. Nothing in the operations of these wells, admittedly smaller operations than that contemplated for the Windfall well, suggests that the Huntersville Chert/Oriskany formation should not be used as a receiving formation for a brine disposal well.

11) The confining zone is less than 50 feet as depicted in the Statement of Basis.

One commenter observed that EPA's Statement of Basis for the proposed permit was incorrect with respect to the thickness of the confining zone above the injection zone. The Statement of Basis indicated that the thickness of the confining zone, immediately above the injection zone, was 50 feet. This was incorrect. The Windfall application provided information indicating that the confining layer immediately above the injection zone (the Onondaga formation) was 14-18 feet thick. EPA has made this correction in the Statement of Basis. Although the thickness of the Onondaga formation is less than originally mentioned in the Statement of Basis, effective confinement by the Onondaga formation has been established by gas storage in the Huntersville Chert/Oriskany gas pools throughout Pennsylvania. In addition, located above the Onondaga formation, are a series of shale and limestone formations that are also considered confining units. These low-permeability formations also separate the receiving formation from the lowermost USDWs.

Another commenter expressed concern that fracturing of the production wells in the area could have introduced fractures in the confining zone within the area of review. The fracturing of the Huntersville Chert/Oriskany gas production wells is not the same as the hydraulic fracturing of unconventional gas production wells in the Marcellus and Utica Shales that occurs today. Unconventional gas wells include horizontal drilling and hydraulic fracturing through numerous stages in the wellbore. The Huntersville Chert/Oriskany gas production wells are vertical wells that had only a few stages within the wellbore hydraulically fractured. These fractures, in the case of vertical wells, do not extend outward for extensive distances like the Marcellus and Utica gas wells. Note also that the UIC regulations for Class II injection wells limit injection pressure to prevent the fracturing of the confining zone **adjacent to the lowermost USDW**. The UIC regulations actually permit the fracturing of the confining zone adjacent to the injection zone if, as in this case, it is not the confining zone closest to the lowermost USDW. However, EPA Region 3 has developed a conservative approach when it issues permits, including establishing injection pressure limits to prevent the fracturing of the injection formation itself.

Finally, another commenter had concerns about the brine wastewater which will be injected into the well reacting with the limestone in the confining zone. The produced fluid being injected is very similar to the brine fluid that is already in the Huntersville Chert/Oriskany formation. In addition, the samples of fluids to be injected generally had a pH range from 6 – 8, which is a neutral range, and will not react readily with the limestone.

12) Will any existing fractures within the injection zone be compromised by the injection operation?

Although the Class II regulations only prohibit the fracturing of the confining zone adjacent to the lowermost USDW, the maximum injection pressure authorized by this permit was developed to prevent both the development of new fractures as well as the propagation of any existing fractures in the injection zone itself. Since the Windfall injection well has yet to be drilled, Windfall submitted geologic reservoir information from gas production wells that were drilled into the Huntersville Chert/Oriskany formation in Clearfield County, located about one-half mile to a mile from the proposed well location (i.e., the Zelman 37-033-30327 and 37-033-20333),information from an injectivity test conducted at the Green Glen #1 well located in Huston Township, Clearfield County, and historical information from the permitting of other wells injecting into the same formation, the Critchfield #1 and the West Shanksville wells in Somerset County. These data indicate that the fracture pressure gradient for the Huntersville Chert/Oriskany formation ranges from 0.90 to 0.95 psi/ft. EPA used a gradient of 0.90 psi/ft to calculate the maximum injection pressure proposed in the draft permit. In the final permit, in response to comments requesting an even more conservative calculation of the injection pressure, EPA used a gradient of 0.88 psi/ft. to calculate a maximum injection pressure to ensure the prevention of new fractures and the propagation of existing fractures in the injection zone during operation of the injection well,.

To obtain the maximum injection pressure, the hydrostatic pressure gradient of the column of water in the injection tubing is subtracted from the gradient of 0.88 psi/ft and that result is multiplied by the depth to the top of the injection zone. By using the gradient of 0.88 psi/ft, the maximum surface injection pressure has been reduced to 2443 psi and the maximum bottom-hole injection pressure to 6425 psi, a reduction of 150 psi from the draft permit. The specific gravity of the injection fluid used to calculate the hydrostatic bottom-hole pressure of the fluid in the injection well was 1.26, the same as the draft permit. A specific gravity of 1.26 represents very heavy brine. Fresh water has a specific gravity of 1.00. This is an extremely high specific gravity for brine and it is not anticipated that fluid coming to this injection well will exceed this value. Therefore, the use of a high specific gravity in calculating the maximum bottom-hole injection pressure reduces the maximum surface injection pressure, accordingly.

Some commenters asked about rock reservoir pressure, what is it, and how is that pressure related to the development of maximum injection pressure. Rock reservoir pressure is not related to the development of maximum injection pressure. Rock reservoir pressure is sometimes mentioned in driller's logs, such as in the driller's logs for production wells 37-033-2033 and 37-033-20341. The rock pressure listed is 2340 psi and 2839 psi, respectively. This pressure represents the pressure recorded when the rock was first drilled into or the rock's pressure after stimulation treatment (i.e., hydraulic fracturing). Instantaneous shut-in pressure, the pressure EPA uses in its calculation of maximum injection pressure, can be obtained from the stimulation treatment, but it is not the same as the rock reservoir pressure. Rock reservoir pressure will decline over the production history of the well and at some point the rock pressure will be too low to economically produce gas from that well any longer.

Other commenters were concerned about the permittee's proposed stimulation program which would apply a maximum injection pressure greater than the maximum injection pressure authorized in the permit. Stimulation is a short term activity, and the operator must return to the normal parameters after it is completed. Typically the vertical extent of such fractures is limited, as shown by the fracturing of conventional production wells, where the fracturing has not led to loss of natural gas because the fracturing is confined to the target zone.

13) Abandoned or improperly plugged gas wells may pose a risk to drinking water supplies.

Without certain precautions, abandoned wells can pose a risk to USDWs by providing a conduit for the migration of fluid out of an injection zone. Therefore, the UIC regulations and the permit impose certain requirements on an injection well operator to protect USDWs from that risk. Specifically, the operator is required to determine whether any abandoned wells exist within a specified area around the proposed well, which could pose a threat to USDWs. This area is termed the area of review. The area of review can be a fixed radius of not less than one-quarter mile around the injection well or may be a calculated "zone of endangering influence," or ZEI. The ZEI calculation is based on geologic parameters found in the injection zone, such as permeability, porosity, injection zone depth and thickness, as well as proposed operational conditions, such as maximum injection volume, injection rates, length of injection, etc. The operator must review all information of public record, and other information of which it has knowledge, to determine whether any abandoned wells or other potential conduits exist within the area of review, that penetrate the proposed injection zone. If abandoned wells are found to exist, then the permittee must either perform corrective action, which requires plugging those wells, or the wells may be used for monitoring the injection formation during operation.

Windfall proposed a fixed radius of one-quarter mile (1320 feet) for their area of review with a maximum injection volume of 30,000 barrels per month. To review the proposed fixed radius, EPA considered past practices at the proposed site and the chemistry of the fluids to be injected. The injection well will be used to inject brine and related fluids into a depleted formation from which large quantities of gas have been extracted, as well as brine similar to that which will be injected. The application also provides information on other wells in the area and on the residents and landowners surrounding the site.

Although not required when applying a fixed radius for area of review, EPA also calculated a ZEI. The ZEI was calculated using parameters based on reservoir information obtained from past drilling records (i.e., Zelman offset production wells 37-033-20327 and 37-033-20333) and injectivity testing information from the Green Glen #1 well owned by Dannic Energy located in Huston Township, Clearfield County. The drilling records and the injectivity testing information were included in the permit application and made available to the public at the local library and at the EPA regional office. The parameters obtained from this information included permeability, reservoir pressure, the depth and thickness of the injection zone, rate of injection and volume. EPA also reviewed published information on the geologic characteristics of the Huntersville Chert/Oriskany formation and verified that the parameters were consistent with those used in other permits for wells injecting into the Huntersville Chert/Oriskany formation. EPA calculated the ZEI using a mathematical model, a modified Theis equation, which in accordance with the UIC regulations at 40 C.F.R. Section 146.6(a)(2), can be used to calculate an area of review. That ZEI calculation identified that after ten years of operation (the permit has been issued for five years), under the operational parameters of the permit such as the maximum monthly volume and the maximum injection pressure, the ZEI will only extend 400 feet from the injection well's wellbore. Because a quarter mile area of review is more protective than the area of review based on the ZEI calculation, EPA chose to base the area of review on the fixed radius method.

Several commenters challenge the use of the ZEI calculation for this site because the model assumes that the injection zone is homogeneous and isotropic, with an infinite areal extent. The modified Theis equation EPA used to calculate the ZEI does assume that the injection zone is homogeneous and isotropic and has infinite areal extent, which may not be the case in an area of review with a nontransmissive fault. However, even though EPA did calculate a ZEI, EPA used an area of review for this well based on a fixed radius of one-quarter mile rather the radius determined by the ZEI calculation. When EPA compared the radius resulting from the

ZEI calculation to that of the one-quarter mile fixed radius, the ZEI radius was at least three times smaller than the fixed radius, resulting in a ZEI area.of review about a tenth of the size of the area of review based on a one-quarter mile fixed radius.

For ongoing confirmation of the adequacy of the area of review, the permit requires an annual pressure fall-off test, even though fall-off tests are not typically required of Class II wells. (It is a requirement for Class I wells disposing of hazardous waste.) A fall-off test will help to determine flow characteristics in the injection zone and can establish whether there is any preferential flow or flow changes over time. The pressure fall-off test will also help to determine whether reservoir pressures become greater than anticipated. If the buildup of reservoir pressure occurs sooner than anticipated, this may require the permittee to change its operational parameters or cease operation so that the maximum injection pressure condition is not violated, or may require a modification of the area of review.

There are no documented wells located within the one-quarter mile area of review that penetrate the injection zone and that could allow injected fluids to move upwards out of the injection zone. According to information submitted by the permittee and the public, there are 17 private drinking water wells and one operating gas well located within the one-quarter mile area of review. However, all of these wells, including the one operating gas well, are much shallower than the injection zone. The UIC regulations do not prohibit locating Class II injection wells near drinking water wells. Instead the regulations and the permit establish requirements to protect the water source for these wells from endangerment by the injection operation. In the case of this injection well, there will be three separate cemented steel surface casings protecting shallow drinking water wells and the lowermost USDW. In addition, approximately six thousand feet of rock containing numerous confining zones exist between the injection zone and the formations that supply drinking water to shallow wells. Finally, as stated previously, no conduits (e.g., abandoned wells that reach the receiving formation) were identified within the area of review that would allow upward fluid migration into USDWs.

When abandoned wells found in the area of review have been plugged as verified by a certificate of plugging which is submitted to the PADEP, EPA accepts this information as confirmation that a well has been plugged properly in accordance with PADEP plugging requirements which were in effect at the time the well was plugged. Plugged wells may also include venting at the surface to avoid gas pressure build-up downhole. In this case, there are no plugged wells within the area of review but there are several nearby plugged wells that reach the receiving formation but they are located outside of the area of review. Commenters complain that at least one of these plugged wells emits gas odors, and express fear that these wells may provide conduits for contamination. The application includes certificates of plugging for all these plugged wells, even though they are outside the area of review.

In addition to the presence of water wells and gas wells, commenters stated that there are wells for geothermal energy in the vicinity of the injection well, although they do not identify any such wells within the area of review or provide any other details about the location of these wells or specify the type of wells they are. Commenters expressed concerns about the potential effect of the injection well in the operations of these geothermal wells. There are several types of Class V wells associated with geothermal energy and the extraction of heat energy from ground water. The most common are associated with heat pump/air conditioning (HAC) systems that extract heat energy from ground water or use groundwater as a heat sink for cooling. HAC systems use very shallow wells that inject the spent water back into the ground water that has circulated through the system. Because these systems involve very shallow wells, they do not create a pathway for contamination and would not be affected by the operation of the injection well. There are also geothermal wells that reach deeper formations but typically the wells are tapping into high temperature formations which are not found in Pennsylvania. No deep geothermal wells have been identified within the area of review.

14) Why won't the injection fluid come back up once it's injected? Won't injecting fluids under pressure allow fluids to make their way back to the surface?

Many commenters expressed concern that once the fluid is injected under pressure it will come back to the surface. As discussed in response #11, there is a confining zone immediately above the injection zone, the Onondaga formation. This is a limestone geologic formation which typically has a very low permeability, giving it the ability to confine and trap fluids from migrating upwards. As noted in this document, the Huntersville Chert/Oriskany formation, the intended injection zone, has produced natural gas in this area for many decades. It is the confinement of this natural gas that enabled successful production. The natural gas and fluids in the formation were also under pressure prior to and during production. It was the confining unit above the Huntersville Chert/Oriskany formation, as well as other geologic factors such as the faulting discussed in response #8, that kept this natural gas in place. Natural gas did not migrate to the surface on its own from the Huntersville Chert/Oriskany formation. It required gas production wells to be drilled into the formation before natural gas could be recovered.

There are also several other factors that will keep the injected fluid in place and not allow it to migrate out of the injection zone. One factor is that the permit does not allow the injection pressure to exceed the injection formation's fracture pressure and thereby prevents fracturing that could allow fluid to migrate out of the injection zone. In addition, there are no other artificial penetrations (e.g., abandoned wells) that penetrate the injection zone within the area of review. The absence of any other artificial penetration into the injection zone within the area of review will prevent injection fluid from migrating out of the injection zone and into USDWs.

To ensure that the injected fluid remains in the receiving formation, the permit requires continuous monitoring of pressure conditions within the injection well. In addition, the annual pressure fall-off testing will establish reservoir pressure conditions and help analyze fluid movement within the reservoir. The permit does not require monitoring wells because the regulations do not require the drilling of monitoring wells and Windfall does not have access to a deep well that penetrates the injection zone such that it could be used for monitoring.

15) There are "deep" coal mined areas located beneath the area of review and injection fluids will be able to migrate into these mines from the injection zone and eventually find their way into shallow ground water or surface water.

The deep coal mines mentioned by commenters do exist below a portion of the injection well area of review as well as throughout Brady Township and the DuBois area. These mines, however, are not deep relative to the depth of the injection zone and are, in fact, located at a depth that requires USDW protection. EPA is requiring that the Windfall injection well have surface casing placed to a depth of 1000 feet below land surface and cemented back to the surface. The depth of the lowermost USDW has been located at a depth of approximately 800 feet. The "deep" coal mines discussed by the public were mined at depths typically less than 800 feet, generally at depths of less than 400 feet below land surface. As discussed more fully in other comments in this document, there are no other wells located within the area of review that penetrate the injection zone that could potentially allow fluid to migrate upwards into these mined locations.

16) Are the fluids being injected into the well toxic, hazardous and/or radioactive? Why don't you just treat the brine water and dispose of it another way?

Individual constituents contained within fluid produced from an oil or gas production reservoir could be determined to be toxic, hazardous or radioactive. However, these fluids, when produced in association with oil and gas production, are exempt from hazardous waste regulation and are not classified as hazardous under the Resource Conservation and Recovery Act (RCRA), 42 U.S.C. § 6901 et seq. In December 1978, EPA proposed hazardous waste management standards that included reduced requirements for several types of large volume wastes. Generally, EPA believed these large volume "special wastes" were lower in toxicity than other RCRA regulated hazardous wastes. Subsequently, Congress exempted the wastes from RCRA Subtitle C pending a study and regulatory determination by EPA. In 1988, EPA issued a regulatory determination that the control of oil and gas exploration and production wastes under RCRA Subtitle C was not warranted, in part because other State and Federal programs, such as the UIC program, effectively manage the disposal of such wastes. Therefore, the UIC program regulates fluids produced in association with oil and gas production activities, but not as hazardous waste. Disposal of these fluids is permissible down a Class II brine disposal injection well.

Commenters often advocated for well construction requirements that apply to Class I hazardous waste wells. Due to the nature of those fluids, Class I hazardous waste wells are the wells subject to the strictest requirements. Some of those requirements include: long string casing cemented to the surface; two-mile area of review; post closure monitoring; mapping of the vertical and lateral limits of the USDWs; analysis of the seismicity of the region; periodic external as well as internal mechanical integrity testing. None of these requirements apply to Class II wells. In short, what the commenters are requesting is that this well be regulated as a Class I well, instead of a Class II well. But as explained above, the Agency made a regulatory determination that brine and associated fluids need not be disposed of, or injected as, hazardous waste.

The public also raised the issue that the disposal of these fluids underground is not safe. All waste produced must be managed in a safe manner and best management practices are typically used by an industry or regulatory agency in determining how and where a waste can be disposed in an environmentally safe manner. If managed and operated properly, EPA believes the risk to the environment by injecting fluids deep underground can be considered safer than other methods of disposal, such as allowing them to be discharged into a stream, disposed of in a landfill or treated and stored in containment pits or storage tanks. EPA also believes that the reuse or recycling of produced fluid is a sound environmental management practice. Although produced brine can be treated, recycled and reused in the hydraulic fracturing process or for the enhanced recovery of oil, the byproduct of this continued reuse of the produced fluid eventually becomes very concentrated and must still be disposed of in some manner. Public and privately owned wastewater treatment facilities are unable to adequately remove many constituents found in brine, for example, chlorides and bromides. When these constituents are discharged to streams or rivers they can pose serious risk to fish and other aquatic organisms living in the stream as well as contribute to serious health effects for people who obtain their drinking water from these streams and rivers. The UIC permitting program is designed to ensure that injection covered by the UIC permits can occur in an environmentally protective manner.

Commenters also questioned whether the addition of corrosion inhibitors and biocides meant that injection would not be limited to fluids produced in connection with oil and gas operations. The additives are not added to the fluid for the purpose of disposal but rather to prevent corrosion in the injection well, and are often also used in production wells. The proper operation and maintenance of a Class II well can require use of such additives.

17) Wastewater injected in the well should be more fully characterized or should be monitored for other parameters.

EPA believes that the conditions found in Parts II, C.3. and C.4. of the permit, are sufficient to adequately characterize and monitor the wastewater for injection purposes. The purpose of this monitoring is to verify that the fluids injected in the well are the type of fluids authorized in the permit. Shallow ground water is monitored for many of the same parameters required by the permit. Therefore, if there is evidence of shallow ground water contamination, those results can be compared against the injection fluid analysis to determine whether the injection well is the cause of that contamination. For example, chloride, one of the parameters for which the permit requires monitoring, can be found in drinking water and it can be found in the fluid proposed for injection. In shallow ground water used for drinking water, chloride values are fairly low, and can typically be found at less than 500 mg/l. Injection fluid typically contains chlorides in excess of 10,000 mg/l TDS and sometimes as high as 300,000 mg/l. If shallow drinking water were to become contaminated by the injection fluid, there would be a significant change that could be observed relatively quickly through the monitoring of chloride.. Other monitoring parameters, such as Total Organic Carbon (TOC), are aggregate surrogates for multiple compounds that are not individually listed. In the case of TOC, monitoring for this parameter identifies the presence of various organic compounds found in produced fluid from oil and gas operations. Produced fluid will typically exhibit a much lower TOC value than a RCRA hazardous waste.

If this wastewater were to be disposed in a different manner (i.e., disposed directly into the environment via stream discharge) then a more extensive characterization would be necessary. However, this wastewater will be injected far below land surface into an existing gas bearing formation similar in nature to where the wastewater was generated. EPA will periodically sample the injection fluid from Windfall's injection operation. If Windfall were to be found injecting fluids not authorized by the permit, which are produced fluids associated with oil and gas production activities, it would be in violation of their permit and subject to enforcement action.

18) Well casing does not last forever. What is the lifetime maintenance plan for this well?

Once the injection well is constructed, EPA will review the completion report which includes well construction information, an evaluation of the well logging, casing and cementing, and mechanical integrity testing. Review of cement bond logs will assure that the well has been properly cemented, in order to prevent the injected fluid from flowing through the wellbore outside the casing. The mechanical integrity test involves increasing the pressure in the annulus (the space between the injection tubing and long string casing) ten percent above the maximum injection pressure authorized in the permit. The pressure must be maintained over a period of 30 minutes for the well to have mechanical integrity. This tests the mechanical integrity of the long string casing, tubing and packer to ensure that there are no leaks. This test will be performed on a yearly basis. Tests for mechanical integrity are also required after an injection well has undergone any type of repair, modification or rework. If there are indications of possible leaks, the test may also include an evaluation of whether fluid movement is occurring outside the casing. EPA can request the permittee to demonstrate mechanical integrity at any time.

Furthermore, Part II.C.2 of the final permit requires continuous monitoring of the injection well for injection pressure, annular pressure and injected volumes. This will enable the operator as well as EPA to determine whether the integrity of the well's long string casing, tubing and packer are compromised over the course of the well's operation. The well will be designed to detect pressure changes. To be able to measure annular pressure, the well's annulus pressure will be set at a positive pressure lower than the injection pressure. If a leak were to develop in the tubing, packer or long string casing, the pressure in the annulus would change significantly which would automatically trigger the well to shut down and cease operating. This would constitute a mechanical integrity failure of the well, and in accordance with Part II.C.2 of the final permit, the operator would be required to cease injection immediately.

Finally, when the operator no longer wants to operate the injection well, it must be permanently plugged and abandoned in accordance with Part II.D.9 and Part III.C of the final permit, which requires that the permittee plug the well in such a manner that plugging does not allow movement of fluids into or between underground sources of drinking water. Since 2001 over 100 Class II wells in Region 3 have been successfully plugged in accordance with the regulatory requirements. Windfall has submitted a plugging and abandonment plan on EPA Form 7520-14 which has been approved by EPA and is incorporated into the permit. Windfall's plugging plan is to be accomplished by one of the methods mandated by the regulations of 40 C.F.R. § 146.10. This plan in provided in Attachment 1 of the final permit.

19) Windfall must provide financial resources should a well failure occur.

Under the UIC regulations, owners and operators of injection wells are required to demonstrate financial responsibility for the purpose of properly plugging and abandoning the injection well when the operation ceases and the well is no longer used for injection. The cost of plugging a well depends, among others things, upon the depth of the well and how the well was constructed. Windfall submitted an estimate from an independent plugging contractor on the cost of plugging the well, as well as a $30,000 letter of credit with a standby trust agreement for the plugging and abandonment of the injection well. EPA Region III reviewed and approved this submission. The estimated plugging cost for the Windfall injection well falls within the range of estimated costs for plugging other Class II-D disposal wells in Pennsylvania. Those plugging estimates range from $10,000 to $75,000, with an average of approximately $32,000. The permit incorporates the requirement that Windfall maintain financial assurance in the amount of the estimate through a letter of credit. (See Part III.D). EPA can require the permittee to adjust the cost estimate and the financial assurance instrument as necessary. See 40 C.F.R. § 144.52.

Several commenters questioned the adequacy of the amount of financial assurance to cover the plugging of the well. These commenters submitted documentation relating to the plugging cost of Marcellus shale wells in Pennsylvania, hazardous waste Class I wells, and Class II wells in Texas and California. It is difficult to compare the plugging requirements of different types of wells in different types of geological settings. Marcellus shale wells typically have horizontal wellbores that can extend 5000 feet or more from the vertical section of the wellbore, making plugging of those wells significantly different than singular vertical wells. Hazardous wastes Class I wells often require specialized cementing which is not necessary in Class II wells. Similarly the geology, labor and material costs, the depth of wells and regulatory requirements for plugging wells in Texas and California may not be comparable to those found in Pennsylvania.

Although a separate issue from the financial responsibility required for plugging and abandonment, the public also asked whether the operator is required to set money aside to remediate contamination of their drinking water if the injection operation fails and allows fluids to migrate into a USDW. The operator is not required to set money aside for ground water remediation. However, EPA does have emergency authorities under the Safe Drinking Water Act (SDWA) if endangerment to USDWs should result from injection activities. Section 1431 under the SDWA allows EPA to take an action against a responsible party if the potential for endangerment exists. This action can include a requirement that the responsible party provide alternative drinking water to citizens affected by the endangerment.

20) Injection well technology was developed in the 1930s. We should be using twenty-first century technology, not primitive, archaic technology.

Although injection wells were initially used back in the 1930s, the construction and operation of injection wells today cannot be compared to 1930's technology. Today's injection wells are multi-million dollar projects. The well construction today incorporates technologies and materials for casing and cementing that did not exist in the 1930s. Even the injection wells that were constructed in the 1960s, and were responsible for some of the contamination incidents that have been cited across the country (e.g., Hammermill in Erie, Pennsylvania), were inferior to today's well construction and operation standards. Reservoir engineering principles that are an essential part of planning an injection well project, before construction even begins, were not used in the 1930s or 1960s. If the design, construction and operation of an injection well incorporate technologies that are available today, EPA believes that injection wells that are permitted through the UIC program offer one of the safer and more environmentally effective alternatives for the disposal of fluids.

21) What is EPA's role in inspecting this well during construction and during operation?

EPA has direct implementation authority for the UIC program in the Commonwealth of Pennsylvania. Therefore, besides permitting, EPA is also responsible for the inspection of underground injection wells and enforcement of the requirements for the operation of such injection wells. EPA has a full time inspector that will be available to inspect the Windfall Injection Well during construction, witness the well for mechanical integrity after construction and periodically inspect the well during operation.

22) The company is responsible for self-reporting to EPA. This does not seem like an acceptable way for EPA to be able to ensure that the well operates properly.

The UIC regulations are similar to most other federal regulations in that they require self-monitoring and reporting to a state or federal agency. EPA expects all operators to comply with the regulatory requirements as well as their permit requirements. Failure of an operator to accurately monitor and report to EPA would subject the operator to possible civil or criminal penalties or both. EPA inspects every Class II disposal well in Pennsylvania at least annually. EPA's inspection of injection well facilities and review of annual reports helps determine operator compliance and supplements self-reporting.

Some commenters expressed concern about evidence of noncompliance in the industry and EPA's lack of vigilance. In particular cases cited by the public in Pennsylvania included Hammermill Paper, McKean County, PA in the 1990s, a CNX injection well in Greene County, PA and an EXCO injection well in Clearfield County, PA. Each of these cases provide good information with respect to EPA's response to a particular environmental concern or a UIC regulatory violation.

Hammermill Paper is a case that developed prior to the promulgation of the UIC regulations and is one of the cases typically cited as to why the UIC regulations were necessary. Hammermill was found to have injected under extremely high pressure, production wastewater. The injection pressure fractured the injection zone, confinement was lost and the waste traveled approximately five miles before it moved upwards through an abandoned well on Presque Isle.

The McKean County case was the result of injection fluid from a rule authorized enhanced oil recovery project migrating upward through an unknown abandoned well and into a USDW used by the public for drinking water. This project was rule authorized under the UIC program because it was in existence prior to the UIC regulations being developed. Area of review analyses were not required for rule authorized facilities. EPA took emergency action under Section 1431 of the Safe Drinking Water Act and required the operator to plug the abandoned the well and provide drinking water to home owners whose private drinking water wells were contaminated. Ultimately, public water was extended from the town of Bradford, PA to the public.

The CNX well in Greene County, PA was a well that was permitted to inject produced fluid from a coal bed methane project into a mine void. EPA discovered through inspection that security at the site was not effective and unauthorized trucks were entering the facility and injecting unauthorized fluids (septic waste and water with high total dissolved solids that were not representative of the fluids the operator reported in its permit application). A penalty was levied against the operator by EPA and the facility was eventually closed and the injection well plugged and abandoned. The unauthorized injection had no effect on USDWs.

The violations at the EXCO well in Clearfield County, were also identified through inspection. EPA discovered that the operator was injecting fluids down a disposal well that lacked mechanical integrity. EPA identified and addressed the violations before any USDWs were endangered. EPA issued a penalty against the company and required the well to be repaired before it was tested for mechanical integrity and placed back into operation.

Each of these cases provides evidence of EPA's vigilance with respect to UIC program compliance and enforcement. Also, as required by the Safe Drinking Water Act, EPA notifies the public of any proposed penalty order and offers opportunity to comment on such orders.

23) EPA should hold another public hearing. The original hearing started an hour late. EPA should have held a second public hearing about seismicity.

Even before EPA provided notice of the proposed permit, EPA held an information town meeting at the Brady Township Community Center with selected members of the public and some elected community, township and state representatives in July, 2012 to discuss the underground injection program. After the public notice and at the request of the public, EPA held a public hearing on the proposed permit on December 10, 2012, at the Brady Township Community Center in Luthersburg, Pennsylvania. Over 250 people attended this public hearing and EPA received oral comments from 29 people in attendance at the hearing. Although it is true that the hearing started late due to transportation problems encountered by the stenographer, the hearing did not end until all of those who wanted to speak had an opportunity to present their oral comments. During the time prior to the start of the formal hearing, EPA informally addressed questions which the audience asked. At the conclusion of the public hearing, EPA extended the public comment period, so anyone who did not speak at the hearing was still able to submit comments via email or mail.

In light of the interest and concerns about induced seismicity, EPA decided to explain in more detail why the proposed well is unlikely to pose a risk of induced seismicity, and to provide for public review some of the scientific work supporting the agency's conclusions. There were no changes to the draft permit. Thus the Region prepared a supplemental statement of basis and reopened the comment period under 40 C.F.R. 124.14(b). Reopening of the comment period under 124.14(b) does not require a second public hearing.

24) EPA should adopt the requirements that Ohio and Arkansas have adopted for wastewater disposal wells.

EPA UIC wells are subject to the permit requirements in the federal UIC regulations. In issuing a permit, the Region considers whether a particular well meets the requirements of the SDWA. Whether a new requirement applicable to all wells of the same class is appropriate is beyond the scope of a permit issuance that focuses on the potential effects of one well.

The Arkansas Oil and Gas Commission has imposed distance restrictions on the construction of new Class II wells from a particular fault system in the state which has been associated with induced earthquakes. The distance restrictions do not apply throughout the state. See Arkansas Oil and Gas Commissions General Rules and Regulations (Feb. 8, 2013), Rules B-43(c) and H-1(s).

The Ohio EPA also amended its statewide regulations concerning UIC Class II wells. The new regulations, which became final as of October 2012, give the state the discretion to require certain specific geological information and pressure testing as part of the UIC well applications. See OAC 1501:9-3-06(C). The amendments also require continuous monitoring of the annulus pressure and an automatic shut-off device which terminates injection if the maximum allowable pressure is exceeded. EPA typically includes these requirements in Calls II disposal well permits. The operation of the Windfall well includes continuous monitoring and an automatic shut-off device.

25) EPA should conduct an environmental impact assessment prior to issuing the permit.

Part 124.9(b)(6) of Title 40 of the Code of Federal Regulations establishes that UIC permits are not subject to environmental impact statement requirements of the National Environmental Policy Act ("NEPA"). NEPA requires environmental impact statements (EIS) when undertaking certain major federal actions. However, under the judicial doctrine of functional equivalent, where a federal agency is engaged primarily in examining environmental questions and there are procedural and substantive standards for adequate consideration on environmental issues, the NEPA EIS requirement does not apply. *See In re American Soda. LLP*, 9 E.A.D. 280, 290-291 (2000). The EPA Environmental Appeals Board has concluded that under the functional equivalent doctrine and Section 124.9(b)(6), EPA is not required to prepare an EIS in support of UIC permits.

26) What happens when the permit expires?

The regulations on Class II permits allow issuance for permits for the operating life of the wells. See 40 C.F.R. § 144.36(a). However, this permit is being issued for five years. Before the end of that five year period, Windfall may request EPA to reissue the permit by submitting a new application. EPA will review the history of Windfall's operation, as well any information on the well obtained during the drilling or from the pressure fall-off tests, and make a determination whether to reissue the permit. EPA's tentative decision of whether to reissue or deny the permit for an additional term is subject to the same public notification and public comment process as an initial permit.

If Windfall decides not to continue its injection operations at the end of the permit term, it must plug and abandon the well in accordance with the regulatory requirements, prior to the expiration of the permit.

Federal Underground Injection Control Program
Permit Appeals Procedures

In its June 10, 2014, order remanding the permit to the Region, EPA Environmental Appeals Board (EAB) indicated that appeal of this permit must first be made to the EAB. The provisions governing procedures for the appeal of an EPA permitting decision are specified at 40 C.F.R. Part 124.19. (Please note that the changes to this regulation became effective on March 26, 2013. See 78 Federal Register 5281, Friday, January 25, 2013.) Any person who commented on the draft permit, either in writing during the comment period or orally at the public hearing, can appeal the final permit by filing a written petition for review with the Clerk of the EPA Environmental Appeals Board (EAB). Persons who have not previously provided comments are limited in their appeal rights to those points which have been changed between the draft and final permits. Appeals may be made by citizens, groups, organizations, governments and the permittee within this procedural framework.

A petition for review must be filed within thirty (30) days of the date of the notice announcing EPA's permit decision. This means that the EAB must receive the petition within 30 days. (Petitioners receiving notice of the final permit by mail have 3 additional days in accordance with 40 C.F.R. § 124.20(d).) The petition for review can be filed by regular mail sent to the address listed below with a copy sent to EPA Region III.

Environmental Appeals Board
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue N.W.
Mail Code 1103M
Washington, DC 20460-0001

U.S. Environmental Protection Agency
Ground Water & Enforcement Branch (3WP22)
Water Protection Division
1650 Arch Street
Philadelphia, PA 19103

See the Federal Register notice cited above or the EAB website: http://yosemite.epa.gov/oa/EAB_Web_Docket.nsf/) for how to file with the EAB electronically or by hand delivery.

The petition must clearly set forth the petitioner's contentions for why the permit should be reviewed. It must identify the contested permit conditions or the specific challenge to the permit decision. The petitioner must demonstrate the issues raised in the petition had been raised previously during the comment period or at the hearing. If the appeal is based on a change between the draft and final permit conditions, the petition should state so explicitly. The petitioner must also state whether, in his or her opinion, the permit decision or the permit's conditions appealed are objectionable because of:

1. Factual or legal error, or

2. The incorporation of a policy consideration which the EAB should, at its discretion, review.

If a petition for review of this permit is filed, the permit conditions appealed would be deemed not to be in effect pending a final agency action.

Within a reasonable time of receipt of the Appeals Petition, the EAB will either grant or deny the appeal. The EAB will decide the appeal on the basis of the written briefs and the total administrative record of the permit action. If the EAB denies the petition, EPA will notify the petitioner of the final permit decision. The petitioner may, thereafter, challenge the permit decision in Federal Court. If the EAB grants the appeal, it may direct the Region III office to implement its decision by permit issuance, modification or denial. The EAB may order all or part of the permit decision back to the EPA Region III office for reconsideration. In either case, a final agency decision has occurred when the permit is issued, modified or denied and an Agency decision is announced. After this time, all administrative appeals have been exhausted, and any further challenges to the permit decision must be made to Federal Court.