UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION III
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Response to Summary Comments for The Issuance of an Underground Injection Control (UIC) Permit for Seneca Resources Corporation

On November 7, 2012, the U.S. Environmental Protection Agency Region III (EPA) issued a public notice requesting comment and the opportunity for a public hearing for the proposed issuance of an Underground Injection Control (UIC) permit, PAS2D025BELK, to Seneca Resources Corporation (Seneca) for one injection well. EPA received numerous requests to hold this hearing and it was held on December 11, 2012, at the Highland Township Fire Hall in James City, Pennsylvania. Approximately 80 persons attended the public hearing of which about 20 provided oral comments. At the conclusion of the public hearing, EPA extended the public comment period through December 31, 2012, and invited any additional written comments. In total, approximately 2600 comments were received.

Comments made 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. Section 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. In addition any potential earthquakes originating outside of this area would not pose a risk to the structural integrity and operation of this injection well. The reopening of the public comment period was limited to these two issues and closed on September 11, 2013.

The responsiveness summary which follows consolidates and provides responses to questions and issues raised from persons who either sent written public comment to EPA, or who provided comments at the hearing. EPA wishes to thank the public for their informative and thoughtful comments and to thank all those from Highland Township who assisted EPA in hosting the public hearing.

1) What does the UIC program have jurisdiction and authority to regulate?

In 1974, Congress enacted the Safe Drinking Water Act (SDWA), 42 U.S.C. Section 300f et seq., in order to protect current and future drinking water resources. Part C of the SDWA (Sections 1421 through 1424) authorizes EPA to implement the UIC program in States which have not acquired primacy to implement the program. As of the date of this document, Pennsylvania has not acquired primacy of the UIC program. Therefore, EPA directly implements the UIC program, including the issuance of UIC permits, in Pennsylvania.

When reviewing the UIC permit application for Seneca, EPA's primary objective is to ensure that the proposed injection operation will not endanger underground sources of drinking water (USDWs) (i.e., aquifer systems containing less than 10,000 milligrams per liter total dissolved solids). Several comments concerned issues which are clearly outside of EPA's UIC program permitting authority. Such issues include the potential for increased truck traffic, the potential for damage to the roads, increased noise, diminished property values, emergency response capabilities, wildlife protection, and surface water spill prevention plans. Although these other concerns may be relevant, they cannot be addressed within the EPA UIC permitting process. Other local, county, state or federal ordinances or regulations may address traffic, road and noise concerns, concerns regarding wildlife protection and surface water spill prevention.

2) Does the UIC permit supersede local land use ordinances?

Highland Township and Elk County have enacted legislation which may regulate activities related to the oil and gas development industries, including banning the disposal of specific types of wastes. UIC requirements do not supersede local, county, or state law or regulations.

The UIC permit includes several provisions which clearly state that the permittee must meet all applicable local, state or federal laws. 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 indicates, "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." The UIC permit is only one of several authorizations that a permittee may have to obtain before it may commence construction and/or operation of an underground injection well.

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

EPA does not have the jurisdictional authority to direct an operator to a particular geographic location within a state. The location chosen by an operator is based on many factors: economics, property ownership, geologic suitability, proximity to production facilities, accessibility, etc. Again, EPA's main responsibility is to ensure the proposed permitted injection operation will not endanger USDWs. EPA cannot deny a permit based solely on residents' opposition to the location, where the applicant meets the requirements for a UIC permit.

4) The public comment period should be longer than thirty days.

The permitting regulations establish the 30-day public comment period. See 40 C.F.R. 124.10(b)(1). However, in response to an individual commenter who at the hearing requested additional time to research abandoned wells in the area, EPA agreed to extend the public comment period until December 31, 2012, an extension of two weeks. In addition, EPA reopened the comment period on the issue of induced seismicity for an additional 30 days, from August 11, 2013 through September 11, 2013.

5) Abandoned wells may pose a risk to drinking water supplies. Area of review should be greater than one-quarter mile.

Two active drinking water supplies within a mile of the proposed injection well rely on USDWs for their water source. The Highland Township Municipal Authority utilizes a spring serving a population of about 300. The spring is located approximately ½ mile north of the proposed injection well. There is also one private drinking water well located about 0.8 miles west of the proposed injection well. Both of these active drinking water wells are located outside the zone of endangering influence and in formations that will be protected through construction and operational requirements of the well. Based on the topography, a spill at the injection well site would flow southward and not endanger either of the drinking water wells.

Abandoned wells near an injection well may pose a risk to USDWs by providing a conduit for the migration of fluid out of an injection zone. Therefore, it is critical that the UIC permit process identifies and properly addresses all the abandoned wells that penetrate the injection zone and that are located within the area immediately surrounding the injection well. The permit applicant is required to conduct a thorough evaluation within a specified area around the proposed operation to determine whether any abandoned wells exist within that area which may 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 an injection well or injection wells for an area permit, or may be a calculated "zone of endangering influence." The zone of endangering influence calculation is based on geologic parameters found in the injection zone, such as permeability, porosity, etc. and proposed operational conditions, such as injection volumes, rates, length of injection, etc. Seneca provided values for these parameters in the permit application. After reviewing the values in the application to ascertain whether they were appropriate, EPA calculated the zone of endangering influence using the modified Theis equation, as specified in the UIC regulations at 40 C.F.R. Section 146.6(a)(2). EPA determined that the zone of endangering influence did not extend beyond the immediate area surrounding the well bore. This means that the calculation estimated that after ten years of injection, the fluid injected would barely rise up at the well bore, and that at a minimal distance from the well bore, there would be no change in fluid level. Nonetheless, taking into account the population, ground water use, and the historical practices in the area, EPA determined that extending the area of review to the one-quarter mile radius, thus incorporating a much broader area than would have been determined by the zone of endangering influence calculation, was reasonable.

The UIC regulations require that the permittee review all information of public record or information that it has knowledge of, to determine whether any abandoned wells or other potential conduits exist within the area of review or zone of endangering influence, that penetrate the proposed injection zone, in this case, the Elk 3 Sand Formation. If abandoned wells that penetrate the injection zone are found, then the permittee must either take corrective action, in the form of plugging and abandonment of those wells, or propose that certain wells be used for fluid level monitoring.

Seneca conducted an abandoned well survey that included a comprehensive review of all State and local data bases and well maps. In addition, Seneca conducted a follow-up field investigation, using metal detectors and other instruments throughout the area of review. Seneca identified only two wells within the one-quarter mile area of review. Well #1328 (API #37-047-00449) was a gas production well located about 0.20 miles to the southeast of the proposed injection well. Well #1328 was properly plugged in 1991 as was documented in a copy of the plugging certificate which was included in the permit application. Well #38281 (API #37-047-23884) is an active gas production well owned and operated by Seneca located about 0.20 miles to the southwest of the injection well. Per the discussion in (11) below, Seneca proposes to rework well #38281 in order to isolate the injection zone and monitor the fluid level.

The applicant has put forth a good faith effort to provide abandoned well information of public record. EPA requested, during the public hearing, that if the public had information concerning any other abandoned wells in the area of review, they should provide that information to EPA so corrective action could be taken prior to injection. EPA has not received any additional information on abandoned wells within the area of review. If at any time an abandoned well is discovered within the area of review, the permit requires the permitee to take immediate corrective action, in the form of plugging and abandonment.

6) There are five unplugged wells within the area comprising the half-mile radius around the proposed injection well.

Per the discussion in (5) above, in the original permit application, Seneca included in its well survey a listing of all the oil and gas wells (active, abandoned, and plugged) within the quarter-mile area of review. Seneca identified only two wells in that survey. Per the discussion in (5), there is an active Seneca gas production well (#38281) and a former gas production well (#1328) which was documented to have been properly plugged. Seneca has since provided additional information in an amendment to the application which includes all wells within the ***half-mile radius*** of the injection well. This updated inventory includes numerous oil and gas wells; some of which are active and others which are inactive. None of these additional wells is within the area of review. It is possible that the five wells to which the commenter refers are included in the updated inventory; however the commenter did not submit any more specific information as was requested at the hearing.

The calculated area of endangering influence is much smaller than the permit's quarter-mile area of review. Therefore, any wells outside the quarter-mile area of review would not present a potential conduit for upward fluid migration. Also, per the discussion in (11), two fluid level monitoring wells will be utilized to measure upward fluid movement due to pressurization of the injection formation. The closer monitoring well (#38281) is 0.20 mile from the injection well.

7) Mechanical Integrity Testing (MIT) and EPA inspections should be more frequent than every five years. There should be additional monitoring required at the injection well site.

There are two specific provisions in the permit which ensure the continuing mechanical integrity of the Seneca brine disposal injection well. The mechanical integrity test (MIT) is conducted prior to the initial injection operation and at least once every five years thereafter, in accordance with the UIC regulations at 40 C.F.R. Section 146.23(b). MITs are also conducted after an injection well has undergone any type of repair, modification or rework, and after the well has been inactive for a period of two years. In addition, the permit provides that EPA can request the permittee to demonstrate mechanical integrity at any time. The MIT involves pressurizing the annulus (space between the injection tubing and long string casing) to an amount at least 10% 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. The pressurized annulus tests the mechanical integrity of the casing and cementing, tubing and packer.

The second assurance of mechanical integrity of the injection well is provided through the continuous monitoring of the annulus pressure during operation of the injection well. See Part II.C.2 of the permit. The well will be designed to detect pressure changes. The well's annulus pressure will be set at a positive pressure considerably lower than the injection pressure, and both annulus and injection pressures will be continuously monitored by pressure gauges and chart recorders. 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 Parts II.C.2 and II.C.5 of the permit as modified, the operator would be required to cease injection immediately. In accordance with Part II.D.3 of the permit, the operator is required to notify EPA of any mechanical integrity failure within twenty-four hours of becoming aware of such failure. The continuous annulus pressure monitoring together with MIT requirements described in this paragraph provide the necessary information on the condition of the well at all times and not just every five years.

The top inspection priority for the UIC program in EPA Region III is for brine disposal injection wells (Class IID). During construction, startup and rework, UIC inspections are routinely conducted. The UIC inspector is ***always*** present during MITs conducted for brine disposal injection wells to assure the test is run properly. In addition, the UIC inspector conducts unannounced inspections periodically to assure the operation is in full compliance with all applicable requirements.

8) Can the proposed injection activity increase the likelihood of an earthquake?

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."*

Induced seismicity background

Under certain conditions, disposal of fluids through injection wells has the potential to cause induced seismicity. However, induced seismicity associated with brine injection is uncommon, as conditions necessary to cause seismicity often are not present. Seismic activity induced by Class II wells could 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 cause movement along the fault line. Induced Seismicity Potential in Energy Technologies, National Research Council, National Academy Press, 2013, at p. 10-11. Although there are approximately 144,000 Class II wastewater injection wells operating in the United States, less than a dozen of these wells have triggered earthquakes of any significance and none of these earthquakes that 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 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. During a seismic event waves of energy are transmitted through bedrock from the origin of the earthquake at the fault.

In those sites where a fault might be present near an injection site, scientists believe that injection can cause 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 during injection, where a fault exists in the receiving formation, 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 cause the formation to shift 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 natural permeability. Permeability is the ability for a fluid to be transmitted through the available interconnected space between the grains in the rock. 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 which provide 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 (the ability of a fluid to move through rock) and low storativity of these kinds of rocks, the potential exists to induce pore pressure increases at considerable distances away from the injection well.

No known faults near the proposed well

Elk County, where the proposed Seneca well will be located, is not a seismically active area and, as specified in the Statement of Basis, the geological information submitted by the permittee did not show any known faults in the area. The United States Geological Survey (USGS) tracks, records and maps faults and earthquake epicenters in certain areas throughout the United States. USGS maps reviewed by EPA do not show any known deep-seated transmissive faults that intersect the proposed injection zone or that could be influenced by the proposed injection operation in the future. The long history of oil and gas production from the receiving formation is also indicative of the absence of transmissive faults because where such faults are present they provide conduits for the escape of oil and gas, limiting the productivity of such formation. 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 organizations that conduct geologic research in Pennsylvania, have not recorded any seismic activity that has originated in Elk County.

Seismic events mentioned by the commenters but which were centered elsewhere do not provide information about the geology of Elk County (including faults), even if these events were felt there. 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. However, 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 epicenter 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 Seneca 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 Elk County or at the Seneca location, and do not provide information about faults in the receiving formation at the well location.

Not only is there no evidence of a seismic event originating in Elk County, but also the number of seismic events that originated elsewhere but were recorded by USGS in Elk County is very low. 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 to present. 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 seismic waves that have been felt in Elk County were transmitted through the bedrock from the epicenter of a seismic event that originated in an entirely different location.

Factors affecting fluid transmission and pore pressure

The public brought to EPA's attention the relatively recent seismic events that have occurred in Ohio, Texas, Oklahoma 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 caused these seismic events. In some cases, these earthquakes occurred in locations where there were no known faults. However, the likely causes behind these seismic events, specifically the geologic setting or the operational history of the injection wells, differ significantly from the proposed Seneca injection operation. Scientific evidence indicates that seismic activity is most likely associated with the depth of a well, the volume and rate of injection, and the injection pressure. In these aspects the proposed Seneca operation differs markedly from 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 well 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 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 and cause seismic activity.

Similar to what happened in Ohio, researchers studying the circumstances that caused the seismic events in Oklahoma and Arkansas believe that over-pressurization of a nearby fault after years of injection may have led to the seismicity. Like in Ohio, injected fluid migrated into Precambrian rocks just below the injection zone and came into contact with an unknown 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 (*Geology,* USGS, March 3, 2013).

Regarding the seismic event in Texas, a study out of the University of Texas at Austin 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 reasons behind the Oklahoma earthquakes are similar to the circumstances described in the Texas situation. The proposed Seneca injection well will be limited to the injection of a maximum of 45,000 barrels per month, less than one-third the total of the Texas well.

The Elk 3 Sand formation, a sedimentary rock of Upper Devonian age, is located at a depth of approximately 2400 feet below land surface (approximately 360 feet below sea level) at the proposed injection well site, and it has higher porosity and greater natural permeability than crystalline bedrock. In the Elk 3 Sand formation the porosity within the rock will more readily store injected fluid and the permeability within the rock structure will allow flow to occur more evenly throughout the formation. Precambrian crystalline basement rock in the area of the proposed injection well is located approximately 12,800 feet below sea level, a significant depth below the Elk 3 Sand formation (Pennsylvania Geologic Survey – General Geology Open File Report 05-01.0). So, the geologic setting and reservoir characteristics of the proposed injection well are entirely different than the circumstances encountered in Ohio, Oklahoma and Arkansas.

In addition, the permit limits the surface injection pressure of the well to 1416 psi, which was calculated in order to limit the bottom-hole injection pressure to no more than 2599 psi. This maximum bottom-hole injection pressure was calculated to ensure that, during operation, the injection formation will not propagate existing fractures or create new fractures in the formation. Limiting the pressure both prevents fractures that could become potential channels for contamination and those that could serve as conduits for fluids to travel from the injection zone to any potentially unknown faults.

It is important to keep in mind that the receiving formation for this well, the Elk 3 Sand Formation, produced, and continues to produce oil and natural gas. During production, oil and natural gas have been removed from this reservoir, depleting the formation of much of the oil and natural gas it contained as well as reducing the formation's reservoir pressure. Earthquakes can occur when a geologic formation becomes under-pressurized (i.e., through geologic formation collapse causing the structure of the formation to shift) or when it becomes over-pressurized. Although the Elk 3 Sand Formation in this location is presently under-pressurized after decades of oil and natural gas production, there has been no evidence of earthquakes due to the removal of the oil and natural gas. Because of the removal of the oil and natural gas and the accompanying lowering of the pore pressure, the formation is a good candidate for the disposal of fluids.

One commenter argues that little brine has been removed from the receiving formation as part of the gas production and that therefore there is not much pore space for the injected fluid. Contrary to what the commenter suggests, the information in the record shows that the pressure in the injection formation for this well has gone down concurrently with gas production. Data submitted by the applicant shows the initial formation pressure when the formation was first produced in 1898, was over 400 psi. Currently, the formation pressure has been shown to range from 20.6 psi to 54.3 psi. This means that the formation can receive more fluids prior to showing an increase in injection pressure. Ultimately, the storage capacity of a particular well is limited by the maximum pressure established in the permit for the well. See Part III.B.4 of the permit. The lower the pressure in the formation, the greater the storage capacity of the formation prior to reaching the maximum pressure established by the permit. As pore space 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 was 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.

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 the 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 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 Seneca injection well, the well is designed to automatically detect a failure due to pressure changes in the well and this would cause the well to automatically stop injection.

10) The Elk 3 Shale is not an adequate confining zone.

The Elk 3 Shale is the confining zone directly above the injection zone. The 26 foot thick Elk 3 Shale has effectively retained the natural gas entrapped below it in the Elk 3 Sand for thousands of years. In the 1950 feet directly above the Elk 3 Shale and below the lowermost USDW, there is a sequence of several additional shale formations known to have very low permeability and which serve as effective confining formations. This information was taken from the original driller's log provided in the permit application. In addition, there are gas producing formations situated between some of the confining formations within that range, from which Seneca is extracting gas. The fact that gas is found between these formations is indicative that the formations are indeed confining. Because of these ongoing gas operations, it would be immediately apparent if any of the injection fluid were to migrate upward and penetrate into any of these zones. There would be an observable increase in the brine generated during gas production from these intermediate formations. Also, as discussed in (11), there will be two monitoring wells used to ensure that the pressure build-up within the injection zone is not sufficient to allow fluid movement to the point where it would endanger USDWs.

11) Fractures from nearby gas production wells may penetrate the injection formation

and may allow fluid movement between formations. Also, the injection zone is not capable of accepting the permitted volume of injection fluid.

If there were any fractures in the injection zone, the risk from such fractures would be that they could serve as conduits for fluid movement into the water-bearing formations above the injection zone. The geologic data used for calculating the pressure build-up within the receiving formation and the potential for upward fluid movement during operation, indicate that the pressure within the injection zone is insufficient to drive the injection fluid into the lowermost USDW. This same geologic calculation (the zone of endangering influence calculation) predicts the formation to have sufficient capacity to receive the permitted volume of injection fluid for a period of ten years.

In addition, the injection operation includes measures that will allow close monitoring of fluid movement between formations. First, as described above, Seneca has wells that extract gas from formations above the injection formation and the confining formation above that. If the injection fluid would move upward to other formations, it would result in an observable increase in the volume of brine generated during production at the Seneca gas production wells.

Second, and more importantly, Seneca will have two fluid level monitoring wells in order to measure the pressure within the injection formation at a given point and time. This measurement indicates the potential for upward fluid movement through any potential unidentified abandoned wells, as well as any unidentified fractures. Each of the proposed monitoring wells will be reworked in order to isolate the Elk 3 Sand injection formation. Seneca proposes to install 4-1/2" casing on a pressure-tight packer set directly above the Elk 3 Sand. The fluid level in each of the wells will be monitored quarterly to assure that the level does not rise to a point where it may endanger the lowermost USDW. If the fluid level at either monitoring well rises to within 250 feet of the lowermost USDW, injection will be terminated until the fluid level recedes. The maximum injection flow rate and/or pressure shall be reduced accordingly. Well #38281 is located about 0.20 miles to the southwest of the injection well and well #01144 is located about 0.35 miles to the northwest of the injection well, about mid distance to the Highland Township Water Authority drinking water springs and wells.

12) Pennsylvania geology is not suitable for underground brine disposal.

While not all of Pennsylvania may be suitable for underground injection, there certainly are areas that are quite receptive to brine disposal. Formations suitable for production and enhanced recovery of oil and gas are suitable for brine disposal. Pennsylvania has historically had thousands of enhanced recovery injection wells of which over 700 are located in Elk County. In addition, there are several active brine disposal wells in the state, some of which have been operating for over 25 years. The zone of endangering influence calculations used to determine the area of review as well as the injectivity testing conducted prior to operation provide a good indication of the formation's ability to receive fluids.

13) Are the fluids being injected toxic, hazardous and/or radioactive?

Individual constituents within the brine produced during an oil or gas production can 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, 42 U.SC. Section 6901 et seq. Therefore, the UIC program does not regulate fluids produced in association with oil and gas production activities as hazardous waste. Disposal of these fluids is permissible through a Class II brine disposal injection well since the fluids are originally produced from similar oil and gas bearing formations.

Commenters raised the issue that the disposal of these fluids underground is not safe. However, other commenters also mentioned that the injection of these fluids deep underground is safer than allowing them to be discharged into a stream or a river or allowing them to overflow or seep into the ground from above-ground containment pits. The UIC permitting program is designed to ensure that the disposal of oil and gas exploration related fluid through injection can occur in an environmentally protective manner. It should be noted that the majority of constituents in the brine originated in the same or similar formation as the Elk 3 Sand where it is being injected.

14) UIC regulations do not guarantee that adverse effects will not occur.

The UIC regulations are intended to reduce the likelihood of adverse environmental impacts from underground injection to the lowest level possible. The regulations require the implementation of multiple and redundant safeguards to achieve this goal. Since the implementation of the UIC program in Pennsylvania, the Region is not aware of contaminations of USDWs resulting from the operation of brine disposal wells in this state; however, no regulation, environmental or otherwise, can ensure the 100% prevention of accidents.

15) Seneca should provide insurance and/or demonstrate financial resources should a well failure occur which results in contamination or other property loss.

Under the UIC regulations, owners and operators of injection wells are required to demonstrate financial responsibility in order to properly plug and abandon the injection well when the operation ceases and the well is no longer used for injection. Seneca has submitted the applicable financial information for EPA to determine that the company satisfies the conditions of a financial statement and that the corporation is capable to cover the costs for the plugging and abandonment of the Seneca well #36268 injection well. EPA reviewed and approved this submission.

It is important to note that EPA also has emergency authorities under Section 1431 of the Safe Drinking Water Act (SDWA) which may be used to address contamination of public and private water supplies. Under Section 1431, EPA is authorized to take an action against any party who causes or contributes to the contamination of a USDW or PWS, where that contamination may endanger human health. Such actions include provision of water treatment or an alternative drinking water supply to the affected population. As stated before, none of the brine disposal operations have ever caused contamination of a USDW.

16) Need for more comprehensive brine analysis; require monitoring of other parameters in the fluid to be injected. Tracers should be put into the brine so in the event of a contamination, it can be traced back to the injection well. Monitoring should be conducted more frequently.

EPA believes that the conditions in Part II, C.3 and C.4 of the permit, are sufficient to adequately characterize and monitor the wastewater for injection purposes. The parameters selected for analysis are those that are commonly found in typical oil and gas produced fluids. The purpose of this monitoring is to verify that the fluids injected into the well are the types of fluids authorized in the permit. If this wastewater were to be disposed in a different manner (i.e., disposed directly into the environment by a stream discharge) then a more extensive characterization would be necessary. However, this wastewater will be injected 2,400 feet below land surface into an existing oil and gas bearing formation similar in nature to where the wastewater is generated. EPA will periodically sample the injection fluid from Seneca's injection operation. If Seneca were to inject fluids not authorized by the permit, the company would be in violation of its permit and subject to enforcement action.

The permit requires that Seneca provide a fairly comprehensive analysis of the brines that are to be injected. The inorganic salts and metals tested for are those constituents which are found in greater concentrations within the brines. In addition, these are parameters which are frequently tested when monitoring ground water. Because they are found in large quantities in brine, and because these chemicals are water soluble, in the event of a contamination of ground water, these constituents would be detectable first and in the greatest concentrations. Monitoring for these parameters would allow for faster identification of a contamination event and for more efficient and faster tracking back to the source.

The final permit requires Seneca to sample, analyze and record the nature of the injected fluid for specified parameters every two years, or whenever the operator observes or anticipates a change in the injection fluid. Seneca will be operating this well as a private injection well, and the permit allows Seneca to inject only produced fluids generated by Seneca oil and gas production facilities. No fluids generated by other facilities are permitted. The permit application indicates that the produced fluids are similar in nature and will all be taken from the Upper Devonian formation. The nature of the produced fluid is not expected to vary much from load to load. If the source of the produced fluid changes or if Seneca otherwise observes or anticipates a change in the produced fluid, the permit requires that Seneca conduct a new analysis in accordance with Part II.C.3 and 4 of the permit.

17) The bottom-hole pressure during injection will be greater than the maximum injection pressure specified.

Yes, the bottom-hole pressure during operation will be greater than the maximum injection pressure. The maximum operating injection pressure specified in the permit has been calculated taking into account what the maximum bottom-hole pressure can be. The bottom-hole pressure is the sum of the maximum operating pressure and the hydrostatic pressure exerted by the 2400 foot column of fluid. Both the maximum operating injection pressure and the bottom-hole pressure were developed to specifically prevent fracturing the injection formation during operation.

18) 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 the environmental impact statement ("EIS") requirement of the National Environmental Policy Act ("NEPA"). NEPA requires an 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 Agency's 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.

Federal Underground Injection Control Program
Permit Appeals Procedures

The regulations governing procedures for the appeal of an EPA permitting decision are found at 40 CFR Section 124.19. (Please note that 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 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. The petition for review can be filed by regular mail sent to the address listed below.

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

Also submit a copy of the petition to the EPA Region III office at the following address.

U.S. Environmental Protection Agency Region III
Ground Water and 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 EAB should review the permit. It must specify the contested permit conditions or the specific challenge to the permit decision. The petitioner must demonstrate that 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 must 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.

Within a reasonable time of receipt of the petition, the EAB will either grant or deny the appeal. Denials are considered final agency action, upon which the permit becomes effective, and the Agency will so notify the petitioner. The petitioner may, thereafter, challenge the permit decision in Federal Court.

When a petition for review is granted, the permit conditions appealed are not deemed to be in effect and if these permit conditions are essential to the operation, the activity may not commence. Individually contested permit conditions are also stayed (they will not be in effect) but other permit conditions are still in effect if they are legally severable from the contested condition.

The EAB will decide the appeal on the basis of the written briefs and the total administrative record of the permit action. If EAB grants the petition, 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 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.