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 EXCO Resources (PA), LLC

On June 4, 2015, the U.S. Environmental Protection Agency Region III (EPA or the Region) issued a public notice in the Dubois, Pennsylvania Courier Express, requesting comment and announcing the opportunity for a public hearing for the proposed re-issuance of an Underground Injection Control (UIC) permit, PAS2D205BCLE, to EXCO Resources (PA), LLC (EXCO), for one Class II-D brine disposal well. EPA offered an opportunity for a public hearing, but received no requests from the public to hold a hearing. The public comment period closed on July 7, 2015. EPA received two sets of comments during the public comment period. All of the information submitted by the applicant, as well as the draft Permit and the Statement of Basis prepared by EPA, were available for review at the DuBois Public Library and at the EPA Region III office in Philadelphia, PA. The initial permit issued to EXCO was effective on May 20, 2005. The current permit is administratively extended until a new permit is issued or denied.

Comments submitted during the public comment period raised questions related to the construction and operation of the existing well. The response to comments which follows consolidates and provides responses to questions and issues raised by those who commented during the public comment period. EPA wishes to thank the public for their informative and thoughtful comments and to the Mahaffey Volunteer Fire Hall, who offered their location for the proposed hearing.

1) Clarification of the term *confining zone*.

A commenter raised questions about references to the use of the term *confining zone* in the Statement of Basis and the draft Permit.

The Region uses the term *confining zone* in different contexts. One context refers to the minimum UIC regulatory requirements of 40 C.F.R. Section 146.23(a)(1). This requirement states that "Injection pressure at the wellhead shall not exceed a maximum which shall be calculated so as to assure that the pressure during injection does not initiate new fractures or propagate existing fractures in the *confining zone* adjacent to the Underground Source of Drinking Water (USDW). In no case shall injection pressure cause the movement of injection or formation fluids into a USDW."

The Region has drafted permit language to adequately protect the *confining zone* adjacent to the injection zone. In this context, the language reflects a conservative approach to ensure that

the Permit satisfies the minimum UIC requirements of 40 C.F.R. Section 146.23(a)(1). The Region calculates the maximum injection pressure (MIP) limit to prevent new fractures or propagate existing fractures of the injection zone as opposed to the *confining zone* adjacent to either the injection zone or the USDW. This methodology establishes a MIP that is more protective than the UIC requirements. As stated on page 3 of the Statement of Basis – Maximum Injection Pressure: "The maximum injection pressure has been calculated to prevent the initiation of new or the propagation of existing fractures in the injection zone during operation of the Injection Well."

In the case of the existing and draft Permit, there are numerous *confining zones* between the injection zone and the lowermost USDW. The injection zone is comprised of the Ridgeley sandstone and Shriver chert and found at a depth of approximately 7,295 feet below the surface. The Onondaga formation is the first *confining zone* adjacent to the injection zone. The Region's methodology established a conservative MIP that is designed to prevent additional fracturing of the Ridgeley sandstone and the Shriver chert. The basis for this methodology is that if injection fluids cannot freely leave the injection zone then the injection fluids cannot easily migrate upwards through any additional *confining zones*, including the Onondaga.

2) One commenter asked how many annuli the Irvin A-19 injection well has.

An annulus is defined as either the space between the casing of a well and the well bore or the space between the tubing and casing of a well[1]. The Irvin A-19 well has multiple layers of tubing, casing and cement. Geophysical logs are used to determine sufficient cement bonding.

One annulus in the EXCO well is located between the well bore and the surface casing. The surface casing is cemented from a depth of 1013' back to the surface, sealing the casing and the well bore with cement and completely sealing this annulus. The long string casing runs from the surface through the entire length of the well and is sealed with cement above the injection zone from a depth of 7232' back to 5434'. The remainder of the annular space between the surface casing and long string casing forms an annulus, and is monitored in accordance with the requirements of the State of Pennsylvania Oil and Gas Code § 78.73. Within the long string casing is the injection tubing, which forms a third annulus.

The annulus between the long string casing and injection tubing is sealed at the bottom with a packer and is filled with fresh water from just above the packer and injection zone to the surface. This is the annulus where monitoring is required as a UIC permit condition. While the other lengths of casing also provide protection from fluid migration, the monitoring of this annulus is required to determine mechanical integrity of the injection tubing and packer. Since the injection pressure is approximately 3000 psi at the surface and increases with depth, any leak in either the packer or the injection tubing will cause the pressure to change significantly in the annulus between the injection tubing and long string casing. This annulus, therefore, will register an immediate malfunction of the injection well operation should one occur.

[1] http://water.epa.gov/type/groundwater/uic/glossary.cfm

3) **A commenter inquired about the meaning of the permit condition prohibiting the permittee from injecting between the outermost casing protecting the USDW and the wellbore as specified in 40 C.F.R. Section 146.23.**

40 C.F.R. Section 146.23 provides the operating, monitoring and reporting requirements for all Class II wells. All of the Class II well permits for wells permitted by the Region incorporate these requirements as minimum permit conditions. 40 C.F.R. Section 146.23 (a)(2) specifies that no injection take place between the outermost casing protecting underground sources of drinking water and the well bore. This well is constructed with surface casing cemented to surface, and is physically not open for injection. Geophysical logs are evaluated by the Region to ensure that wells have been cemented to an acceptable standard of integrity. Operating without mechanical integrity would be a violation under UIC regulations, as would exceeding permitted MIP requirements.

4) **A commenter asked which annulus pressure the draft permit requires the operator to continuously monitor, and whether the pressures in each of the annuli should be used to activate an automatic shut in of the well.**

The Region requires the operator to continuously monitor the pressure in the annulus between the injection tubing and long string casing. This annulus will be filled with water, pressurized, and monitored via a pressure gauge at the surface attached to the wellhead. As explained in Response No. 2, if a leak in the injection tubing were to occur at any point during injection, the pressure will change in the annulus and indicate that a mechanical integrity failure has occurred.

Disposal wells are also equipped with automatic shut-off valves to continuously monitor for integrity above and beyond the routine pressure test. The permit requires that there be positive pressure in the annulus at all times, usually 1-300 psi. The automatic shut-in device is set to shut in the well when the annular pressure exceeds a preset maximum and minimum annular pressure. If the automatic shut-off is tripped and the well automatically shuts in, the operator will also be automatically notified via cellular phone. If there is a leak in the tubing and packer, the well will equalize while shut in but no fluids will escape through the long string casing.

5) **A commenter asked about the possibility of fluid migration between the long string casing and the seat of the surface casing.**

A commenter also raised the question as to whether fluid which might rise to the surface between the long string casing and the surface casing would result in a permit violation. If there is evidence of fluid migration, a complete investigation would be performed in order to determine if a violation has occurred and enforcement is warranted.

6) A commenter asked how we determine when there is a "significant" leak or "significant" fluid movement under 40 C.F.R. 146.8 and permit condition Part II E.1.

From the time the well is constructed until the well is plugged, the provisions of the permit require proper construction, operation and monitoring of the well. Once the injection well is constructed the Region will review the well completion report. This report includes well construction information and an evaluation of the well logging, casing and cementing, and mechanical integrity testing. All of these report items are designed to provide additional safeguards against any potential well leakage. 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 pressurizing the annulus to a pressure 10 percent above MIP as authorized in the permit. A significant leak is defined as more than a five percent decrease of annular pressure in 30 minutes; if annular pressure decreases more than five percent in 30 minutes the well has failed mechanical integrity. If pressure decreases by less than five percent over a period of 30 minutes, the well is deemed as "having mechanical integrity". The mechanical integrity test verifies that the well has no significant leaks in the injection tubing and packer. Mechanical integrity tests are required on a 5-year basis, and are also required after an injection well has undergone any type of repair, modification, rework, or at the Director's discretion. 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 Irvin A-19 well permittee has previously submitted cement records to document the significant movement aspects of maintaining mechanical integrity. Additional tests and logging were previously required for this well to verify that cementing logs document the quality of cement on the long string above the injection formation. "Significant leakage" or "significant fluid movement" are not determined by individual constituents within the injected fluids, but by the loss of mechanical integrity. A well is in violation if it loses mechanical integrity. This means that *no* amount of *any* constituent can be lost, and the permit does not need an added condition to define an amount of a specific contaminant that is "significant" as suggested by the commenter.

It was also suggested that a well be drilled into the lowermost USDW to monitor for injected fluids. Pennsylvania does not have drinking water well drilling regulations at this time and the presence of a well penetrating multiple USDWs may endanger shallower formations if not cased and cemented properly. Provisions for monitoring injection pressure and mechanical integrity are designed to protect the lowermost USDW. There are no known drinking water wells in the ¼ mile area of review of this well, which has been in operation since 2005. No water quality issues have been reported to date.

7) **A commenter suggested that the permit should include language that overtly permits the use of biocides and corrosion inhibitors for proper maintenance and operation of the well and also require EXCO to seek approval before biocides and corrosion inhibitors are added to the intended injection fluid.**

All wells are potentially susceptible to corrosion, scale, and bacterial build up, including drinking water wells, oil and gas production wells, and injection wells, and such wells require the use of biocides and corrosion inhibitors for proper operation and maintenance. Many wells, including drinking water wells, require the use of additives such as acids, algaecides, biocides, corrosion inhibitors, etc. for standard operation and maintenance procedures. These additives are not added to the fluid for the purpose of disposal but rather to prevent corrosion in the well. Based on the comments received, the permit has been modified in Part III B. 2 to identify that produced fluids and additives necessary for maintaining the integrity of the well are permitted. The corrosion inhibiting and oxygen scavenging additives proposed for maintaining the well are products that will be mixed with the produced fluid and are designed to preserve the tubular goods. These products are used in very low quantities; about one part per 4,000. In these minute concentrations, their toxicity is estimated to be very low.

The proper storage and handling procedures for these additives are provided by the manufacturer, and the well treatments are done by service companies knowledgeable in the handling and operation of the service requested by the injection well operator. For these reasons, it is not necessary to add a prerequisite to the permit for pre-approval of any identified additives used for maintenance of the well. Further information can be obtained from both the American Petroleum Institute (API) and the American Water Works Association (AWWA) regarding industry practices associated with well maintenance additives.

Federal Underground Injection Control Program
Permit Appeals Procedures

In a June 10, 2014, Order remanding a UIC permit to the Region, the EPA Environmental Appeals Board (EAB) indicated that any appeal of a UIC 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. Section 124.19. (Please note that the changes to this regulation became effective on March 26, 2013. *See* 78 Federal Register 5281, Jan. 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 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 Branch
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 the change 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.