"Connection for Oil, Gas & Environment in the Northern Tier, Inc."
1155 Nimble Hill Road | Mehoopany, PA 18629 | 570-837-0972
C.O.G.E.N.T.

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MAR 13 2014
INDEPENDENT REGULATORY REVIEW COMMISSION

March 13, 2013

Environmental Quality Board
PO Box 8477
Harrisburg PA 17101-2301
RegComments@pa.gov

RE: Oil and Gas Well EP Performance Standards – Comment Summary

Please be advised we generally support the proposed rulemaking as written for adoption. In addition, we have provided comments regarding important issues we advocate for either modification or inclusion in the rulemaking.

- We recommend the adoption of the rulemaking's definitions in their entirety along with additions for buffer zone, unique buffer zone, vista, viewshed and well pad spacing.
- We recommend the adoption of §78.15 in its entirety along with additions that will provide for adequate protections of our public resources as coexisting with unconventional shale gas exploitation.
- We recommend the adoption of §78.51(d)(2) as written that provides the interpretation of "exceed" as meaning better than; thus inferior water supplies are restored to SDWAS and those that "exceeded," having superior quality are restored to that same pre-drill quality. This is guaranteed to us in Act 13 of 2012.
- We recommend the adoption of §78.52(a) having the revised area of review be completed after the well is spud, for active, orphaned or abandoned wells within a 1,400' distance.
- We recommend the adoption of all six provisions that pertain to conventional drillers. The environmental record in which we have noted supports these revisions to the Oil & Gas Act based on thirty years of practical experience.
- We recommend that contaminated residual waste only be buried in permitted centralized landfills.
- We recommend the adoption of §78.57(e) as written in its entirety replacing underground or partially buried storage tanks within a three year period.
- We recommend the creation of two new permits to address issues related to onsite processing §78.58.
- While the provisions related to §78.59c. centralized impoundments are necessary; we recommend the Department work towards evaluating all existing CIs and eliminating the process by requiring 100% closed loop systems. CIs have become past practice for most operators, the floor needs to be raised for those complacent in progressing to more modern methods.
- Based on information we've provided we recommend that production reporting be revised from semi-annually to a monthly reporting basis for unconventional wells.
- Based on information we've provided, we recommend the bonding requirements be revisited and revised to a more adequate schedule.
- We recommend that other surface issues be included in this rulemaking that provide where there is a lack of local zoning such issues as noise, lighting and setbacks are adequately addressed such that residents within 750' may be comfortable within their homes. The living experience next to well sites has made this necessary to address.
- Due to the uncertain status of Act 13 of 2012 and the Commonwealth Court, we recommend that provisions related to well permits, well location restrictions, presumption, air emissions, and subchapter E all be codified as regulatory language rather than referencing the Act.
- We recommend increasing the well plugging funds fees to better address the backlog of abandoned and orphaned wells needing attention.

Best Regards,

Emily E. Krafjack

Emily E. Krafjack
President

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March 13, 2014

Environmental Quality Board
P. O. Box 8477
Harrisburg, PA 17105-8477
RegComments@pa.gov

RE: Rulemaking – Environmental Protection Performance Standards at Oil & Gas Well Sites

Dear Environmental Quality Board Members:

Connection for Oil, Gas and Environment in the Northern Tier, Inc. C.O.G.E.N.T focuses on the five county region of Bradford, Sullivan, Susquehanna, Tioga and Wyoming Counties. C.O.G.E.N.T. is a resource for landowners and communities alike striving to find and advocate for a balance that supports public health and safety, community and the environment with the needs of industry. There are approximately 183,000 souls in the five county 3,987 square mile region. Unconventional gas well sites and facilities have been located within and around our rural, farmland and forested communities, nearby family homes, schools and local hospitals. Because of these facts, we take a keen interest in the long awaited rulemaking, *Environmental Protection Performance Standards at Oil & Gas Well Sites.*

We want to see a robust environmental protection program to ensure the areas we love most and live within, are adequately protected for public health and safety, the environment and our communities at large. We want to see adequate measures to protect our environment and thus our water resources, to ensure that our region will continue to have economic development coupled with a desire by our families continuing to live here, and for tourists continuing to visit our region experiencing in our opinion, one of the most scenic regions of our great Commonwealth. It is very

possible to ensure the integrity of our region, the public and industry within the shadow of each other, without knowing of the other, whether it is on private or public lands. The key to attaining this, are robust regulations that create this reality in the future.

To date, our region hosts 43% of the Commonwealth's unconventional spud wells. Of the total wells inspected in the state, 50% of those are located in our region and are responsible for 54% of the violations recorded by DEP. Since our region is well enveloped within the area of exploitation, we offer our comments on this rulemaking.

78.1. Definitions

Approximate original conditions – While some may argue that land use is outside of DEP's jurisdiction to regulate, and is largely an issue to be resolved between the lessor and the operator, we do not agree. Marcellus Shale is not a typical landowner land use issue. We want to see this definition in place as it provides protection for our Region's rural and agricultural and forested integrity. Land use issues are not solely landowner issues as the flavor of land use directly relates to the integrity of our regional community. The Region hosts approximately 43% of the total unconventional wells within the Commonwealth. Reducing reclamation to standards other than preconstruction contours may greatly unravel the beautiful fabric of our Region's aesthetic value. When industry negotiates agreements to do otherwise, we only need to reflect back in recent history to unscrupulous land men who did their bidding and more than a few landowners regret making decisions they had made during that time. Lease agreements and regulations protect landowners when they lack information or knowledge concerning land use issues. We strongly recommend the Department adopt this definition at a minimum in the scope and spirit in which it is written.

Buffer Zone – an area designated that is beyond the setback in which mitigations are required to enable both the operator and public to enjoy their respective activities. Buffer zones are created ideally to create a safety and comfort corridor

which is beneficial to both operators and the public enjoying the same area on publicly owned lands.

Centralized impoundment – (2) – We applaud the Department's recognition of air pollution that may endanger persons or property. While it is true, that the air program does indeed regulate some air regulations on oil and gas facilities, there are still some sources that are not effectively regulated with emission control technologies. Additionally, at the recent Appropriation's Budget Hearings, it was noted that the expected fee increase will provide for an addition of field staff complement in the program, some of which will have air quality specialist expertise. This is really an excellent step forward by the Department which will enable the Marcellus Shale Play to reach that delicate balance where all may thrive. Therefore, we strongly recommend the Department adopt this definition at a minimum in the scope and spirit in which it is written.

Gathering Pipeline - As an advocacy organization, C.O.G.E.N.T. advocates on many unconventional shale gas issues in addition to environmental protection performance standards, one being pipeline safety. Thus, we are well familiar with and aware of many issues related to gathering lines. The very first draft of this rulemaking [1/22/2013] defined ***Gathering Pipelines – A pipeline that transports oil, liquid hydrocarbons or natural gas from individual wells to an intrastate or interstate transmission pipeline. The term includes pumps, headers, separators, emulsion treaters, tanks, regulators, compressors, dehydrators, valves and associated equipment.*** Subsequent to that draft, industry comments provided that by the 2nd draft, the definition substantially changed. ***Gathering Pipeline – A pipeline that transports oil, liquid hydrocarbons or natural gas from individual wells to an intrastate or interstate transmission pipeline.*** This is the same definition that is in the rulemaking that we are now commenting on.

At the Tunkhannock hearing, it was noted by the industry group that the gathering pipeline definition is not consistent with the DOT definition. We are well aware of that fact. We also are well aware that the DOT PHMSA – CFR definition is not a definition created by the regulator, but rather, it is the *1st edition, issued April 2000*

of American Petroleum Institute Recommended Practice 80 which has been incorporated in total by reference. However, some limitations to the RP are defined in CFR Title 49 §192.8. Now, as a pipeline safety advocate, I can tell you there are important issues related to incorporating recommended practices into any regulation. First, there is the issue of transparency. It is very difficult for the average citizen to even know what a recommended practice is, let alone know where to find it and whether they are reading the most current version. Secondly, they are recommended practices, not standards, so there is wiggle room in them. There is no reason to conform to a DOT definition or RP80 for that matter as we are not dealing with pipeline safety regulations here, with the exception of 78.68(h) which pertains to corrosion control as adopted in Act 13 of 2012. All other provisions deal with environmental issues related to soil, water protections, and HDD. The spirit of regulating gathering line pipeline safety has not presently designated DEP with that authority. If you were to ask any pipeline safety advocate and even some in industry, they would tell you that RP80 is convoluted and ambiguous. Thirdly, we are very concerned that by adopting/referencing any API RP into this or any other rulemaking that we are treading on dangerous ground in setting such a precedent. Any pipeline safety advocate can aptly advise of the problems encountered when regulations refer to a recommended practice rather than explicitly state the regulation in full detail. Therefore, we strongly recommend that this definition is not revised to comply with API's RP80 or the Department of Transportation definition, but rather stands as is written.

Mine influenced water – We recommend the definition be adopted at a minimum as it is written. MWI is a new concept into water sources used for hydraulic fracturing. The Department needs to be as detailed as possible with this definition and involved in the implementation of MIW usage. Creating a good definition as is indicated here will flow forward into good and reasonable regulation and compliance.

Oil and Gas Operations – A comment has been submitted that there are not earth disturbance activities associated with oil and gas exploration, production, processing or treatment operations or transmission facilities. Due to the fact that

when an incident occurs, such as at the YARASAVAGE site, during hydraulic fracturing, earth disturbance did in fact occur as the operator quickly and out of necessity needed to construct containment areas to attempt to control the flow of over 200,000 gallons of fluids. Therefore, we recommend that this definition be adopted as written at a minimum.

Unique Buffer Zone – A Buffer Zone that is created to further provide for mitigations for special scenic areas, such as waterfalls, glens, vistas, nationally recognized features and Commonwealth recognized ecological resources within Commonwealth lands managed for recreational and wildlife management purposes may have a Unique Buffer Zone (UBZ) applied. These areas need to be designated. Designations may be done by public resources agencies and need to involve public input.

Vista – a pleasing view, especially one seen through a long, narrow opening which is designated as such by a Commonwealth or County Agency.

Viewshed – an area of land or water or that is visible to the human eye from a fixed vantage point, and of particular scenic value that is deemed worthy of preservation against development or other change as designated by a Commonwealth or County Agency.

Watercourse – We urge the Department to be consistent across programs and adopt the same definition for watercourse regulatory language that is noted in 25 PA Code §105.1.

Well pad spacing – minimum distance between well pads.

§ 78.14. Transfer of well ownership or change of address.

While beyond the scope of this rulemaking, nevertheless, this is an issue that landowners are concerned about, that is not being notified when their lease is sold, especially when there are permits issued concerning their property with an operator other than whom they are leased. Most recently, this occurred with Chief Oil & Gas LLC. Permit 131-20367 Garrison West Unit 3H where landowners were leased with a different operator and found out via the community grapevine that their property was proposed to be laterally crossed with this well and others. This

was months in advance of any news release stating that the leases had been sold. Repeated calls to their operator availed no information. Landowners had a variety of concerns; some of them related environmental protection issues. It is well known that not all operations are created equal and thus, landowners are concerned about what those operations may mean to their property when such a variety of methods are employed. This is a simple matter of notification that operators can easily comply through regular mail.

(d) The permittee shall notify all leasehold landowners subject to the transfer of a change in address or name within 30 days of the change.

78.15. Application requirements (includes Conventional Drillers)

This provision also applies to conventional drillers. While conventional drilling locations are much smaller than unconventional, they still have the possibility of accessing areas that require special and careful evaluation. Since the area of review is generally limited to the discrete area, we see no unreasonable hardship here to the conventional drillers. What we see is a measure of consideration towards core habitat areas for example. We need to consider the comprehensive view of the amount of new disturbed areas that are subject to both conventional and unconventional drilling. We need to sufficiently and adequately protect such areas towards the great balancing act of exploitation. We support these provisions as they pertain to the conventional drillers at a minimum as they are written.

78.15(d). Application Requirements.

Well pads, access roads and gathering lines have been located either within or in close proximity to core habitat areas in Wyoming County. [Sharpe Location ESX13-131-0010, EDF 1H-6H ESX10-131-0002] Core habitat polygons typically represent the aggregation of core habitats for the assortment of species of concern occurring in any one area. Core habitat areas host critical communities, species of special concern. The fact that we have such areas within our region, attests to the healthy environment in which we live. Because we've been unable to adequately protect

these areas on private lands, it is imperative to protect these areas on our public lands. Therefore, we recommend this provision as written.

78.15(f)(1). Application Requirements.

We recognize that Sullivan County is home to some of the most scenic vistas and viewsheds in our region. In addition, every county within the Northern Tier has public lands that may be subject to exploitation. These public lands and more, are home to threatened and endangered species, critical communities, species of special concern, scenic vistas and viewsheds, high quality and exceptional value streams and wetlands, and are well known for recreational opportunities and support regional tourism.

Public resources, such as parks may be affected by the development of a nearby pad. 200 feet is just too short of a distance for notification. Resource agencies need to be made aware of nearby pads such that they may provide input to either DEP or the operator for matters of public safety. For example, it is now customary that the operator locates a truck crossing sign near the access road approach area. Should a very busy park be located nearby, within 600 feet they may want to suggest that the operator place a yellow flashing light in addition to the sign to alert park visitors who may be unfamiliar with the industry associated heavy and oversized loads. Thus, there needs to be an extension from 200 feet to 600 feet.

Regarding notifications:

78.15(f)(1) This subsection applies if the proposed surface location of the well is located:

*(i) in or within **600 feet** of a publically owned park, forest, game land or wildlife area.*

*(iii) within **600 feet** of a national natural landmark*

*(v) within **600 feet** of a historical or archeological site listed on the Federal or State list of historic places.*

New provision:

The poor siting of a well pad along the Loyalsock Trail [permit# 113-20208] at some points within 30 feet [as measured on Google Earth] of the cleared well pad area

indicates the need for better planning. A gem of Sullivan County, the Loyalsock Trail provides outdoor enthusiasts with recreational opportunities that support Sullivan County's tourism and the local economy. Emphasis on ensuring the trail experience and most enjoyed Canyon Vista for instance, is a very important concern among many folks in the Northern Tier Region and beyond. This is a primary example of why we are recommending an additional provision in section 78.15(f)(1). There needs to be a mechanism in place where county planning offices are able to submit comment regarding pad and infrastructure placement whether or not county zoning may apply.

The Northern Tier Region is home to the Endless Mountains. Our Counties, such as Sullivan County have scenic vistas and viewsheds which are valuable assets contributing to regional tourism and the local economy. Thus, protecting vistas and viewsheds are very important to a county such as Sullivan County. Because of that, Sullivan County's Planning and Community Development Department has a great deal of data regarding their vistas and viewsheds. It is important to note that DCNR also has considerable information on viewsheds and vistas. Agencies such as DCNR and Sullivan County through the use of available technology are able to plot well site and facility locations and analyze data indicating the effects on the viewshed and propose better sitings that adequately, appropriately and reasonably mitigate, minimalize, avoid or eliminate those effects. Additionally, further consideration needs to be given to areas such as Tioga County's Pine Creek Gorge, the Pennsylvania Grand Canyon of which 12 miles have been designated as a National Natural Landmark. The 200 feet measure is simply too inadequate to sufficiently protect such a splendid and nationally recognized area. The siting of well pads, pipelines and facilities within the viewsheds can have a dramatic effect upon whether people still consider that place as special. That effect can have a dramatic effect upon the region's tourism and related economy. Thus, we recommend this additional provision:

An applicant proposing to drill a well, place a pipeline or any facility at a location that is deemed to be ***<u>in or within one mile</u>*** *of a designated vista or viewshed's*

lookout point or trail location shall notify both the applicable resource agency and the appropriate county planning office in accordance with paragraph (2) and provide the information in paragraph (3) to the Department in the well permit application. The applicable resource agency and/or county planning office may provide suggestions as warranted to mitigate the effects on the vista and viewshed such as moving the location beyond the ridgeline. The Department needs to consider both comments and mitigation suggestions in regards to issuing such a location permit.

[Please note, Penn State University Department of Landscape Architecture students and Professor Brian Orland lead a workshop in Marcellus Landscape Design during December 2013, in Sullivan County. The students provided demonstrations on how Marcellus sitings are able to be done using landscape design and thus preserving our vistas.]

New Provision - Creation of Buffer Zones:

Buffer zones (BZ) are created to ensure the royalty owners maximum exploitation while ensuring the public's maximum enjoyment on publically owned lands. This is not a restriction, but rather a simple buffer zone which will provide a measure that will allow the public's enjoyment coexisting with resource extraction. Buffer zones will create a sense of harmony and eliminate unnecessary conflicts. These buffer zones are small enough to provide industry with flexibility, predictability and consistency while providing a measure of consideration and respect for the community at large. It is within these buffer zones that mitigation measures are taken to ensure that the both the public and industry have equal access and coexist within the shadow of each other.

These areas will need to be classified in such a manner that DEP has a method to track them within their system to ensure that buffer zones are designated and indicated on the permit applications. Special scenic areas, such as waterfalls, glens, vistas, nationally recognized features and Commonwealth recognized ecological resources within Commonwealth lands managed for recreational and wildlife management purposes may have a Unique Buffer Zone (UBZ) applied. These areas need to be designated. Certain trail areas, such as those that are nationally recognized need to be designated in parts as scenic corridors. (SC) These areas also need to have a method of designation within the DEP permitting system. In

determining designations, there needs to be a public participation component. These buffer zones are minimal zones, the operator can very well choose to further respect the public access to these resources and propose mitigation measures within a greater buffer zone distance.

- *A buffer zone of 600 feet applies to:*
    - *Perimeters: publically owned parks, wild, natural or environmentally sensitive areas*
    - *Buildings on public lands*
    - *Trails (300 feet on each side)*
    - *Camping areas*
    - *Natural national landmarks*
    - *Historic sites listed on the Federal or State list of historic places*
- *Within these buffer zone areas, mitigation efforts shall be at a minimum as follows:*
    - *During all drilling, fracturing and completion operations sound barriers aesthetically designed with consideration to the surroundings shall be erected. The sound barriers shall be are able to substantially suppress noise to 45 decibels at either the publicly owned land property border or in cases where the activity is within publicly owned lands 45 decibels at the nearest building or permanent camping area. Natural ambient noise levels are an important aspect of the public land recreational experience.*
    - *Where necessary, trails need to be relocated an adequate distance from the industry activity to ensure a pleasurable experience. Consideration needs to be made for dust, noise; proximity to possibly dangerous events and ensuring the site is sufficiently secured from access by unauthorized individuals. Trails shall be relocated in such a way that the hiking experience is not diminished and further, that both parties have maximum access to their activity pursuits.*

- *When necessary, in order to afford a more pleasant camping experience, consideration shall be given to noise levels during the drilling, fracturing and completion operations. This consideration may involve mitigation such as abandonment of the established primitive camping area and the creation of a new area with at a minimum, a like for like exchange of facilities such as rest rooms, etc. In such cases, the public agency is responsible for the new primitive camping area selection with operator agreement. Costs incurred in the process of abandonment and creation of the new primitive camping area is at the operator's expense. The operator as an option may choose not to do site mitigation when the natural ambient noise levels are attained.*
- *In all designated camping areas special considerations need to be taken regarding lights during drilling, fracturing, workover rig, and any other night work activity. Ideally, lighting such as "Lunar" nonglare lighting directed at the work area is preferable to typical overhead directional lighting that sends light as much as over a thousand feet beyond the work area. Operators shall take appropriate measures to avoid any unnatural lighting in all designated camping areas.*
- *All permanent equipment on a producing well site shall be housed in such a manner to suppress noise to the point that the pre-development natural ambient noise levels are attained at the well pad perimeter.*
- *Once the well pad is hosting producing wells, trees and tall native plants that are customarily found within the immediate area shall be planted near the well pad perimeter in an adequate manner to camouflage the well pad. Plants shall be of an appropriate height to camouflage well pad equipment upon planting. In forested areas the ideal is that the well pad is adequately camouflaged so that it is not readily visible.*

- *A unique buffer zone of 1000 feet (500 feet on each side) applies to:*
  - *Scenic and natural features*
  - *Designated scenic corridors*

- *Within the unique buffer zone areas, mitigation efforts shall be at a minimum as follows:*
    - *Sound barriers aesthetically designed with consideration to the surroundings shall be erected in order to suppress noise to either 45 decibels or natural ambient noise levels which ever may be greater.*
    - *When necessary, the operator shall take adequate mitigation measures to enhance the public enjoyment experience within areas of scenic and natural features, and also designated scenic corridors. Such measures for an example would be to provide continual adequate access to those scenic and natural areas that may be hampered with a well pad location. Measures may extend from adjusting the well pad location/size to building a new trail to create a similar public access and experience to the designated scenic and natural feature or scenic corridor.*
    - *Particular attention shall be paid to disrupted scenic viewsheds. This may involve the establishment of a new vista overlook location, with accompanying trail or other actions that would adequately provide for an opportunity for the both the public and industry to coexist. Mitigation may involve slight pad relocation to beyond the ridgeline. This does not mean that the industry does not work within the viewshed, but rather it means that the industry gives careful consideration to the aesthetic value of such areas and makes every effort to adequately camouflage or enhance these areas.*

- *The 45 decibel limit is not created lightly. Ambient noise testing has indicated that our rural areas are quiet having ambient noise tests results at 35 decibel levels. Noise experts have noted that reaching 40-45 decibel levels are adequate in rural areas and the industry is able to achieve such levels with reasonable effort. 45-50 decibel limits are more prescribed in suburban areas. 50-55 decibel limits are prescribed in urban areas. Prior to Act 13, the only industries that were able to widely utilize 60 decibel limits were the FAA and the military.*

It is important to note that this 'prescribed standard' in Act 13 has now been overruled by the Commonwealth's Supreme Court, based in part on the Environmental Rights Amendment. Prior to Act 13 operators were advising that they were designing facilities to meet 45 decibel limits, so it is able to be done. It has been noted in "The World Health Organization (WHO)'s document entitled "Guidelines for Community Noise" that 50 decibels creates moderate annoyance outdoors during both daytime and evening timeframes.

- *Public lands having wild or natural areas and areas considered environmentally sensitive of three square miles or less in size shall not have surface disturbance, all resource exploitation shall be accomplished through subsurface activities such as through horizontal drilling from a wellbore based in an area beyond the three square mile area.*

- *Well pad design shall incorporate more than the average number of wells than are typically planned on private land well pads. The goal; maximum exploitation with minimal disturbance.*

78.15(f)(2). Application Requirements.

The 15 day comment period does not provide public resource agencies a sufficient timeframe for adequate consideration of the public resource and to provide a sufficient response. Municipal governments that may have a municipal park located within the notification range may not have adequate time to respond within the 15 day period. Many municipal governments only meet on a monthly basis to discuss business and determine actions. For example, in the small rural communities located within the Shale region, many Supervisors are only part time and some may only be at the municipal office to review mail at the monthly meeting. 15 days may afford inadequate time in every case to read the letter or formulate sufficient response. Some of the small rural county governments only rely on a small planning

staff under whose purview this review and response would be generated. Some counties only have a county planner and no support staff. A 15 day comment period does not permit enough time with the on-going work load to provide for adequate attention and a sufficient response. Finally, with current workloads, the 15 day comment period does not provide state resource agencies such as DCNR with an adequate review period to the depth that would be sufficient to appropriately respond.

78.15(f)(2). 15 Day Public Resource Written Comments – Revised

The applicant shall notify the public resources agency responsible for managing the public resource identified in paragraph (1), if any. The applicant shall notify the appropriate county planning department/s regarding any possible well pad, pipeline or facility that potentially may be sited within locations of scenic vistas/viewsheds. The applicant shall forward by certified mail a copy of the plat identifying the proposed location of the well, well site and access road and information in paragraph (3) to the public resource agency or county planning department at least ***30 days*** *prior to submitting its well permit application to the Department. The applicant shall submit proof of notification with the well permit application. From the date of notification, the public resource agency or county planning department shall have* ***30 days*** *to provide written comments to the Department and the applicant on the functions and uses of the public resource and the measures, if any, that the public resource agency or county planning department recommends the Department consider to avoid or minimize probable harmful impacts to the public resource where the well, well site and access road is located. The applicant may provide a response to the Department to any such comments* ***The Department needs to consider these impacts and mitigation suggestions when evaluating and issuing the permit. The Department needs to respond to the comments made by the public resource agency or county planning department.***

78.15(f)(4).

Paragraph (3) the "discrete area" we are interpreting to be the "limit of disturbance" for lack of a corresponding definition. Based on our interpretation, the applicant's attention to only the "discrete area" is myopic at best. We've had significant experience now to know that the "discrete area" is not the only area of impact near any natural gas well pad, pipeline or facility.

For purposes of public resources, primarily due to the fact that we have plenty to base our experience on private land impacts, we can say with most certainty, limiting the information provided to the "discrete area" is dramatically insufficient. Well pads fluctuate with traffic from low to high volume. The operator's schedules may coincide with the public's seasonal visitation frequency with the public resource, thus the operator needs to take this into account and provide for adequate public safety measures. The impact of noise and dust issues beyond well pads and facilities can affect the functions and uses of the public resource for an area hundreds of feet away from the "discrete area", especially in view of camping. Lookout points for vistas/viewsheds can be greatly impacted by well pads, pipelines and other facilities greatly affecting the functions and uses along with enjoyment, greatly beyond the "discrete area." Namely, a well pad sited [permit# 113-20208] along the Loyalsock Trail along with hikers from our region reporting impacts along the Midstate Trail, strongly indicate reasons for the operator to consider the functions and uses of trails beyond this "discrete area." Additionally, previously forested, now cleared areas considerably increase the incidence of blow downs in the forest perhaps as much as 100 feet from the "discrete area" which adds to the corresponding fragmentation issues. The applicant needs to indicate what ongoing mitigation efforts will be made to address the additional loss of trees beyond the "discrete area".

In summary, 78.15(f) needs to be revised to increase the 200' notification zone to 600'; create another notification zone of one mile for vistas, viewsheds and within or in one mile for certain trail locations; create a new provision for buffer zones and

unique buffer zones; increase the comment period from 15 days to 30 days and include county planning departments, and define the "discrete area" along with expanding the application 78.15(f)(4) to ensure an adequate detail of submitted information. These revisions provide for opportunities to properly mitigate and avoid siting problems in the future. We recommend these revisions to 78.15(f).

78.15(g). Application Requirements.

Since this provision is codifying Act 13, we only reiterate that the Department needs to place conditions on the well permit as necessary to adequately provide for avoidance or mitigation of impacts to public resources guaranteeing the public's access and enjoyment to the pre-development functions and uses. Consideration needs to include the time period of the operator's Marcellus experience along with their compliance record being relevant aspects for such permit conditions. With this consideration, we recommend this provision as written.

78.17. Permit renewal.

We support the provision to notify all entities as required to be notified pursuant to section 3211(b)(2) of the act. Since permits are not always renewed the nearby residents have no other way of knowing the operator's intentions. Circumstances may change such that a resident may want to contact the operator with questions or DEP regarding specific concerns regarding the permit. Therefore, the residents as stipulated by the Act need to be notified accordingly. We fully support this provision as written and recommend its adoption.

78.18. Disposal and enhanced recovery well permits.

Presently, the Commonwealth has a limited number of such wells. However, the EPA is moving forward with the issuing of a number of UIC permits. It is true the industry is having water disposal issues. We do need to be able to dispose of concentrated un-recyclable flowback and produced waters in the best methods that are respectful of the environment. Such methods will require containment and

perhaps even on-site processing. The Department needs to be anticipating more UICs and have appropriate environmental measures and safeguards in place. We therefore, support this provision and recommend its adoption as written.

Subchapter C. Environmental Protection Performance Standards.
78.51(d)(2). Protection of Water Supplies

C.O.G.E.N.T. supports the interpretation as based on Act 13, guaranteeing those with private water supplies, whom had pre-drill tests which were superior to the Safe Drinking Water Act Standards that in the event they are subject to a replaced or restored water supply that the water supply must be comparable to the quality of that superior pre-drill water supply. C.O.G.E.N.T. supports that those water supplies, as guaranteed by Act 13 which failed to meet SDWAS that those water supplies are to be replaced or restored to SDWAS. Homeowners of superior private water supplies whom to no fault of their own had their water quality impacted by the industry should not be further penalized with an inferior restored or replaced water supply as compared to their pre-drill test. The inconvenience, worry and additional stress placed on a family necessitates that they be justly compensated with the same superior water quality their pre-drill test reveals. Much in the same way, the inconvenience, worry, and additional stress placed on a family, requires that those water supplies that did not meet SDWAS, as just recompense for the inconvenience need to be restored or replaced to SDWAS. The operator is addressing the water supply; therefore, it is the responsible action to do so entirely.

Obviously, there are some considerations that need to be made in regards to the restored or replacement supply. First, we recommend that the Department assign a key person to assist the family. The affected homeowner ideally, will interact with this key person rather than the Operator. This person may act as either an Ombudsman or a Liaison between all parties and assist the affected homeowner. The reason for this key person is to ease homeowner stress and eliminate an adversarial situation that may have resulted from the water quality impairment. The idea is to assist the homeowner, advocate on behalf of the homeowner and have

the situation resolved as quickly and as free from stress as possible. This person needs to have knowledge of water standards and treatments and be able to understand the homeowner's budgetary and other concerns.

In regards to superior supplies that are restored with a water treatment system, the homeowner needs to have input into the treatment methods employed. The Ombudsman or Liaison needs to be able to communicate the pros and cons of each treatment method made available. Some treatment methods, such as those that add salt to the treatment process may be a health concern with some and thus, a potassium treatment may be preferred. The homeowner needs to have direct input through the Ombudsman or Liaison as to what their preferences may need to be. Any reasonable preference shall be deemed acceptable. The homeowner has been inconvenienced enough, through no fault of their own. They previously had a superior water supply. Operators state that it is the rare event that water supplies are impacted. Therefore, as compared to the costs of drilling a gas well, the costs involved with providing a treatment system in a home is a reasonable expense that must be borne by the Operator. In the case of the home treatment system, it is the Operator's responsibility to bear all installation, operation and maintenance expenses associated with the meeting the pre-drill superior water supply quality. Additionally, a separate electric meter needs to be placed on the home as the Operator needs to be responsible for any additional electricity consumed due to the home treatment plant.

In regards to a homeowner with a superior pre-drill water supply who happened to have a home treatment system already employed, it is the responsibility for the Operator to maintain and operate any additional treatment to what they may have had pre-drill. For example, perhaps the homeowner had a pre-drill sediment filter on their home treatment system. Should the homeowner determine they will continue with the sediment filter, operational and maintenance expenses will be borne by the homeowner. However, if their previous water system was damaged or is not compatible with the new treatment plant, it is the Operator's responsibility

to bear the costs of installation. Regardless of the system particulars regarding what options the homeowner may be responsible due to pre-drill treatment; it remains to be the responsibility of the Operator to bear the entire amount of any additional electricity consumed by a home treatment plant.

In regards to a homeowner with a superior pre-drill water supply that is placed on a public water supply, the Ombudsman or Liaison needs to be able to communicate effectively with the affected homeowner regarding any concerns they may have regarding the public supply. There are folks that may have allergies/immune system issues with chlorine in a water supply. There are several ways that this may be addressed in a home. The Ombudsman or Liaison needs to be able to listen to the suggestions from the homeowner since when folks have such health issues they are acquainted with what may be needful and more than likely will consult their medical doctor or specialist. The Ombudsman or Liaison needs to be able to communicate to the Operator that the certain device/s are needed and that this additional expense will also be borne by the Operator due to a present health condition. The Ombudsman or Liaison needs to be able to communicate with the affected homeowner and provide information as to the new water supply and how the connection will occur. The Operator is responsible for all costs incurred with connection and the purveyor's monthly or quarterly billings.

In regards to a homeowner's water supply that failed to meet SDWAS pre-drill, the Ombudsman or Liaison needs to explain the pre-drill deficiency to the homeowner. Educational materials shall be provided. The homeowner needs to be able to understand what the health effects are that may be attributed to such water quality. The homeowner needs to be provided with materials that explain the manner in which that particular deficiency may be addressed through treatment, the costs involved with that particular treatment and the maintenance costs involved. The Ombudsman or Liaison needs to determine whether the homeowner may be able to afford the treatment for the pre-drill deficiency. The Operator is responsible for the installation of the pre-drill deficiency corrective measure. The homeowner is

responsible for supplies and maintenance of the corrective measure. For example, if the pre-drill test reveals coliform in the water supply and the homeowner chose an ultraviolet light as treatment, the costs of the future light replacement is borne by the homeowner. The original light is the responsibility of the Operator. Often there are a variety of treatment options available to the homeowner. The homeowner needs to determine which treatment they prefer, but they also have to indicate to the Ombudsman or Liaison that they understand the maintenance schedule and can afford it. Once the Ombudsman or Liaison has indicated that the homeowner can afford the selected treatment method, then the operator needs to address the remaining deficiencies with treatment. The Operator is responsible for the entire system installation and only the maintenance and operational expenses of those deficiencies caused by the Operator's impact to the supply. The homeowner is responsible for the maintenance and operational expenses related to any pre-drill deficiency. Regardless of the system particulars regarding what options the homeowner may be responsible; it remains to be the responsibility of the Operator to bear the entire amount of any additional electricity consumed by a home treatment plant.

In regards to a water supply that did not meet SDWAS and is being replaced by a public water supply, the Ombudsman or Liaison needs to be able to explain the deficiencies in the pre-drill supply and the manner in which the public supply is superior. The Ombudsman or Liaison needs to be able to communicate with the affected homeowner and provide information as to the new water supply and how the connection will occur. The Operator is responsible for all costs incurred with connection and the purveyor's monthly or quarterly billings.

Finally, the Operator is responsible for the maintenance and operation of a home treatment plant indefinitely, forever. These treatment plants are very involved when the water has been very impacted. Expenses involve monthly electric, maintenance and other operational expenses. Such an expensive system may deter a potential buyer of the home in the future, which will result in the present owner

losing money on perhaps their largest investment and due to no fault of their own. Thus, the Operator is responsible for these expenses for as long as the home shall stand and be inhabited.

In the case of the home that is connected to a public water system, the Operator needs to be responsible for these monthly or quarterly costs for as long as the home is owned by the affected homeowner or an immediate member of their family.

Any homeowner that enters into an agreement with the Operator outside of this process must provide a written statement to the Department as provided by their attorney verifying that they have entered into an agreement with the Operator outside of this process and they have used a privately contracted attorney. This is to ensure that no homeowner is unreasonably coerced into waiving their right to their water quality as guaranteed by Act 13. The Department shall retain this letter in the respective determination file.

When private water supplies are affected by an Operator, the affected homeowner's water supply must be restored or replaced to SDWAS or to the superior supply they had previously enjoyed. That is the spirit of Act 13's guarantee to the homeowners. The letter of the law needs to comply with that spirit. With consideration of these particulars C.O.G.E.N.T. recommends this provision whereby our water supplies restored or replaced supplies meet the objectives as defined by Act 13.

78.52.(d) Predrilling or prealteration survey.

Due to the manner in which former farmland has been subdivided, on occasion there are landowners whose private water supplies may be located on adjacent properties. This may happen in the case of both springs and water wells. Generally, the water rights are spelled out in the corresponding deeds. There have been instances where the operator missed sampling a water supply. There have been instances where the owner of the private water supply as stipulated in the corresponding deeds were not provided with the sample results, but rather their

neighbor whom owns the property where the private water supply is located was provided the results. There needs to be a mechanism that would provide the owner of the private water supply whose source is on another's property as specified in the deed for them to receive a copy of the sample results.

78.52a. Abandoned and Orphaned Well Identification. (Includes Conventional Drillers)

78.52a(a). We recommend revising the area of review. Tioga County experienced a serious situation [Guindon – Butters Wells] with an abandoned well issue due to a hydraulic fracturing communication.

[http://stateimpact.npr.org/pennsylvania/2012/10/12/perilous-pathways-abandoned-wells-dont-factor-into-pennsylvanias-permitting-process/ *Perilous Pathways: Abandoned Wells Don't Factor Into Pennsylvania's Permitting Process*]

This incident caused environmental harm and cost the operator a great deal of time and money.

After the well is spud, the operator of a gas well or horizontal oil well shall identify the location of ***active,*** *orphaned or abandoned wells within* ***1,400 feet*** *measured horizontally from the vertical well bore and* ***1,400 feet*** *as measured* ***at the surface, the entire length of the horizontal bore*** *in accordance with subsection (b). The assessment needs to be entire subsurface depth of above and below the vertical and horizontal well bore in any gas bearing zone.*

We realize that this area of review may indeed cover a greater depth than may be at risk by the operator in relationship to the formation in which they are working. However, there is a social responsibility of industry to help identify all wells as it was this industry in general, who created the largely estimated 300,000 orphaned and abandoned wells inventory.

The STRONGER September, 2013 Review [page 51] encouraged the Department to "*consider regulations to require operators to evaluate and mitigate potential risk of*

hydraulic fracturing communication with ***active, abandoned or orphan*** *wells and other potential conduits that penetrate target formation or confining formations above." (STRONGER Guidelines Section 9.2.1)* Our recommendations, albeit with detailed suggestions align with the STRONGER recommendations.

Additionally, unconventional drillers are not the only drillers utilizing horizontal drilling technology now. During the August, 2013, TAB subcommittee meetings public comment period in State College, a representative from Penneco made comment that his company is now utilizing horizontal drilling in shallow formations. Further review of this idea brings attention to this news article in September, 2013.

http://www.post-gazette.com/businessnews/2013/09/22/Horizontal-drilling-fracking-begins-in-old-shallow-oil-and-gas-fields/stories/201309220115

Horizontal drilling, fracking begins in old, shallow oil and gas fields
September 22, 2013 4:00 AM

As Excerpted:

The newer business, Horizontal Exploration, was designed to profit from technology and services that followed Marcellus operators into Pennsylvania in recent years.

Horizontal Exploration has drilled three horizontal, or lateral, wells so far and has permits for another eight in Pennsylvania.

It fracked the first well this month and is awaiting results.

The wells are about 2,000 feet deep and extend between 3,300 feet and 5,300 feet horizontally.

"We think you should be able to do these for $800,000 to $900,000 [per well]," Mr. Thompson said.

But at the moment, the company is spending about $1.3 million a pop. It's still toward the bottom of the learning curve, he explained.

A Marcellus well, by contrast, can run anywhere from $4 million to $10 million. It needs, on average, 5 million gallons of water for fracking.

Horizontal Exploration is using only about 120,000 gallons of fluid to frack its shallow wells.

The conventional laterals will never produce anywhere near the amount of oil and gas coming out of the deeper Marcellus wells, but Mr. Thompson is hoping for at least 10 times the bounty of a vertical shallow well and a quicker payback period -- about 18 months, compared to four years.

The Upper Devonian sandstones are thinner than the Marcellus. Some are only 20 feet thick compared with the Marcellus' average thickness of 70 feet or more, said Dan Billman, president of Mars-based Billman Geologic Consultants Inc., which helps companies identify suitable spots to sink both conventional and unconventional wells.

While shale rock is tight and relatively impermeable, sandstone is porous and oil and gas easily flow through its tunnels.

That means the pressure needed to frack it is a fraction of what's required for a deep shale well.

And some conventional horizontal wells are designed not to be fracked at all, Mr. Billman said.

One of the earliest horizontal shallow wells in Pennsylvania, with advice from Mr. Billman, was drilled by Freeport-based Phoenix Energy Productions in 2010.

Since then, the company has drilled two more horizontal wells in Washington County and hasn't fracked any of them.

Penneco Oil Company Inc. in Delmont, on the other hand, has been fracking horizontal shallow wells for several years now. It perforates the casing at more than a dozen stages and pumps "off-the-shelf" frack fluid additives into oil and gas formations about 3,200 feet under Greene, Westmoreland and Allegheny counties with

great success, according to Penneco's COO Ben Wallace.
"We hear this from a lot of drillers -- they get called because oil and gas companies look up our completion reports," Mr. Wallace said.
Penneco's sandstone wells cost "several million" dollars to complete, Mr. Wallace said, and the company plans to drill about 10 horizontals a year.

Several other companies, such as Warren County-based Pennsylvania General Energy and South Side-based Catalyst Energy have secured permits from the Department of Environmental Protection to drill horizontally in shallow reservoirs.
Shallow, or conventional, drillers report their production annually, not every six months as Marcellus operators must, so the results of these efforts won't be available until next year.

We advocate that the assessment be done after the well is spud as the spud indicates a clear intent that the operator is going to drill that well. Doing the assessment at that point, allows sufficient time to alter their drilling plans if need be [should their plans be within AOR of an active, orphaned or abandoned well]. Rather than incurring the expense of drilling a well they may not be able to safely fracture, they can amend their drilling permit for a modified horizontal well bore.

Let's not forget the goal here, which is to identify active, orphaned and abandoned wells and avoid/prevent an environmental incident. The Operator would only be required to plug the well/s that have been deemed at risk by their hydraulic fracturing operation. The remaining identified wells are to be placed in the DEP inventory of orphaned and abandoned wells waiting plugging. We see this process in a threefold manner; 1- identify the active, orphaned and abandoned wells, 2 – perform a proper risk assessment to determine whether or not the identified active, orphaned and abandoned wells may cause a communication event, 3 – advise the Department of the all wells and plug at risk wells accordingly. The Operator upon identifying at risk well/s could determine to abandon their plans to hydraulically fracture the well and not be responsible for the at risk well/s that would be deemed necessary for plugging. The Operator also has the option of amending the permit for a modification.

All drillers, both conventional and unconventional need to complete the active, abandoned and orphaned well identification process. With some conventional drillers transitioning into the horizontal drilling method, it is even more imperative

that the conventional drillers complete an adequate assessment to avoid future environmental impacts.

78.52a(b)(3).

In our rural areas, property changes hands and thus, it may be very possible that a landowner may be aware of an orphaned or abandoned well/s that may be located on property they formerly owned, or they may be aware of such well/s on their present property. We realize that landowners have an obligation to advise the Department of such wells, but most landowners are not intimately aware of that requirement placed on them. Therefore, we support providing a questionnaire to all the landowners within the area of review and also, requiring a DEP fact sheet on orphaned and abandoned wells is included in the well permit certified mail notification packet that is mailed to landowners advising them of the new well permit.

Based on information shared at the TAB subcommittees this summer, we recommend that DEP not only continue to collect data creating a database, but also that the revised assessment be done after spudding a well. We also recommend both a questionnaire and fact sheet regarding orphaned and abandoned wells be included in the landowner notification certified mailings.

78.53. Erosion and sediment control.

We appreciate the updated clarification of this provision. We recommend the adoption of this provision at the minimum as it is written.

78.55. Control and disposal planning; emergency response for unconventional wells.

78.55(d.2) ***Copies***

We support that copies of the well operator's PPC plan shall be provided to the Department, PFBC or the landowner upon request as well as being available at the

well site. Not every landowner is going to be interested in having the PPC. However, there are landowners that are concerned about the site specific measures taken regarding storing, using, generating or transporting regulated substances to, on or from a well site. The details therein, such as, containment systems employed and equipment that may be kept onsite during drilling and fracturing operations that can be utilized to prevent a spill from leaving a well site may be important to our farmers with consideration to their crops and livestock. Our organic farmers may need to provide this information to their cooperative.

Incidents in our region such as the ATGAS blowout in Bradford County and YARASAVAGE blowout in Wyoming County both point to the need to have adequate planning and emergency response and thus, a detailed PPC Plan. We have come to the conclusion that in the case of an emergency, such plans are invaluable. The submitted plan must be site specific. It is imperative the Department review these plans. On the local level, we've seen how initial emergency response plans provided by operators, for example, such as Williams Field Services' Emergency Response Plan was so inadequate the Township's Planning Commission and Zoning Board Solicitor rejected and returned it to the Williams regarding the proposed Sickler Compressor Station in Washington Township, Wyoming County. Thus the devil is in the details and whether it is a PPC or Emergency Response Plan they must be adequately prepared and reviewed. C.O.G.E.N.T. recommends this provision at the minimum as it is written.

78.56. [Pits and tanks for t]Temporary storage.

C.O.G.E.N.T. advocates the use of tanks as the preferred method for both conventional and unconventional operations. One operator in our region, Cabot has already utilized above ground modular structures. Our water resources need to be adequately protected and it is well known that above ground temporary storage is a superior practice in regards to eliminating environmental impacts associated risks. Adequate security and safety measures are necessary to protect the public and the

facility from wildlife and unauthorized access. Many of these sites are near homes and they need to be adequately secure to protect nearby properties as well.

We recommend the provisions related to modular above ground containment structures as they can assist operators in their recycling methods and water storage along with being a better environmental practice near our homes. We prefer the use of tanks over the use of pits, especially in the case of unconventional drilling. Since this practice is lingering with perhaps only a few unconventional drillers, we are receptive to these revised regulations. In reality however, we would like to see all unconventional operators cease using pits and rather utilize tanks.

78.56(a)(1)

As noted on page 53 of the STRONGER, September, 2013 Review "*The regulations do not require liners or secondary containment around tanks or other facilities storing polluting substances, but such liners are recommended practices.*" With sites located near within and around our rural, farmland and forested communities, many times nearby our homes, schools and even local hospitals, we really want to see safeguards consistently employed operator to operator, site to site. We urge the Department to consider adding this recommended practice as a provision to this rulemaking as noted by the STRONGER Review.

78.56(a)5.

This provision meets the recommendation of the STRONGER, September. 2013 Review as noted on page 38 of the report. *(STRONGER 2013 Guideline Sections 5.5.3.f. and 5.5.4.b.)* C.O.G.E.N.T. concurs with the Department's inclusion of the fencing provision. We recommend the adoption of this provision at a minimum as it is written.

78.56a6. (includes Conventional Drillers)

We support the implementation of this provision for both conventional and unconventional drillers. While we realize that this may create an additional cost for

the conventional drillers, our Commonwealth is moving forward to a new age as a major oil and gas producing state. It is unfortunate that our conventional drillers have not kept pace with technology, enhancing their operations to better practices. Now that we are in this changing time, many entities within our state have had to adapt. More rural residents have had to adapt to having industrial facilities nearby their homes. Our state highway and local road systems have had to adapt. Our counties and local governments, and at times, even our school districts have had to adapt by designating more resources to address oil and gas related issues. Thus, our conventional drillers have come to a time now where they also need to adapt and comply with this provision.

On February 20, 2014, West Texas Crude was noted at $103.30/Barrel as reported by *Energy Assurance Daily*. At the Tunkhannock Hearing, Mark Cline, a fourth generation oil man and PIPP Board member testified that Pennsylvania's conventional wells produce Penn Grade Crude Oil which is the best lubricating oil in the world. So, it just makes sense that the Pennsylvania conventional drillers are benefiting from these increasing prices and top dollar for the world's best lubricating oil. It does appear that now, they can easily afford to bring their operations in line with the modern technologies. According to the regulatory analysis form, the cost the conventional drillers would bear for compliance with this regulatory change ranges from $40 to $5,000. This is really a reasonable expenditure that will provide for public health and safety and environmental protections.

We've taken the time to consider the information provided at the EQB/DEP rulemaking hearings by conventional drillers. Testimonies provided give an unclear review of their operations. One aspect they've strongly advocated is that they have not created environmental harm with their operations and that the past 30 years of the O&G Act proves that. We put forth here information to the contrary, that is neither true for all operators, nor all of the time. We also note that, it is indeed time to update the O&G Act for conventional drillers based on new and available

technologies that they may employ concerning tanks and horizontal drilling as just two examples. We'd like to draw your attention now to just two easily discovered items that indicate why conventional drillers need to be subject to adequate regulations that protect our public health and safety, environment and especially water resources. While we can sympathize with their plight on perhaps an added expense, when it comes to public health and safety, it is also necessary that serious consideration is given regardless of the business size and scope.

- Conventional Driller - Crude Oil & Brine Water Spill

http://www.pabulletin.com/secure/data/vol43/43-14/620a.html

[43 Pa.B. 1868] [Saturday, April 6, 2013]

LAND RECYCLING AND ENVIRONMENTAL REMEDIATION

UNDER ACT 2, 1995
PREAMBLE 1

Kline Lease, Harmony Township, **Forest County**. Atlantic Environmental Group, Inc., 453 State Route 227, Oil City, PA 16301 on behalf of Cougar Energy, Inc., 1049 West 2nd Street, Oil City, PA 16301 has submitted a Notice of Intent to Remediate. On or about March 26, 2012, during operation of an oil well, a gathering/product transmission line ruptured resulting in approximately 55 gallons of well fluids (crude oil & potentially brine water) to be released onto the soil. On April 20, 2012, a second spill occurred down gradient of Kline Well No. 17 resulting in the release of crude oil and brine water that impacted soils and a channel of an intermittent stream. The Notice of Intent to Remediate was published in *The Titusville Herald* on March 2, 2013. The intended future use of the site will be for agricultural use.

- Conventional Driller – Contaminates Drinking Water

http://stateimpact.npr.org/pennsylvania/2012/02/22/dep-fines-driller-for-contaminating-drinking-water-in-forest-county/

DEP Fines Driller for Contaminating Drinking Water in Forest County

FEBRUARY 22, 2012 | 3:51 PM

BY *SUSAN PHILLIPS*

The Department of Environmental Protection says **Catalyst Energy** will have to pay a fine and conduct remediation for its oil and gas production in Forest, McKean and Warren counties. The DEP fined the Pittsburgh-based oil and gas company $185,000 for violations at non-Marcellus wells. The DEP says Catalyst operations polluted 14 residential drinking water supplies in Hickory Township, Forest County.

A press release issued by DEP lists high levels of iron, manganese and methane. All of the water wells are within 1000 feet of a Catalyst well, so the company is presumed liable under current state law. DEP spokesman Kevin Sunday says

methane migration occurred through nearby abandoned wells. He says the department didn't determine how drilling polluted the wells with manganese and iron.

Sunday says Catalyst restored the water in some of the wells, and are providing water to other residents. Some of the wells are attached to hunting cabins and so are not used year round.

DEP inspections found that Catalyst did not install controls to prevent sediment runoff at Forest County wells. State regulators say the company also caused oil and fluid leaks at sites in Forest, Warren and McKean counties. DEP says Catalyst can not drill or frack any new or existing wells unless they show they are in compliance with all regulations.

We also strongly caution the Department regarding separate regulations for conventional drillers. Two-tiered approaches for any type of regulation only serve to weaken and confuse. We strongly advocate that the Department note within each provision the 'target audience'. As a suggestion, the regulatory language may be indicated as follows.

00.0 Title

- 00.01 Pursuant to conventional oil and gas operations, operators shall.....
- 00.02 Pursuant to unconventional oil and gas operations, operators shall....

01.0 Title

- 01.01 This section applies to both conventional and unconventional oil and gas operations.

This creates clear language and understanding for all stakeholders, the Department, the regulated community, and the public. It is also helpful as there are some operators with both conventional and unconventional operations. It is much clearer to have all regulations in the same format and in the same document.

78.56(3)(4)(8-15) Pits.

The STRONGER, September 2013 Review [pg 36] notes that "*there are about 1,600 drilling production pits in Pennsylvania.* Further, the review team determined that

the DEP's experience with pits has shown that, although their use is decreasing, many liner failures still occur with pits and other types of waste are being dumped into pits. The review team recommends that the DEP consider adopting regulations or incentives for alternatives to pits used for unconventional wells in order to prevent the threat of pollution to the waters of the Commonwealth." (STRONGER 2013 Guidelines Sections 5.3.3.d. and 5.5.3.e.)

C.O.G.E.N.T. concurs with the STRONGER recommendation and supports the team's recommendation with application to both conventional and unconventional operators.

In the absence of eliminating pits entirely, we support these provisions as they provide for more stringent oversight. However, we strongly urge at a minimum that pits are discontinued in unconventional activities.

78.56(11, 16-17) Pits – Unconventional Operations.

We have serious concerns over the use of pits with unconventional operations. It is our understanding, and it was noted in the February 20, 2014 Penn State Extension Webinar regarding the recently released production and waste reports, that the industry has largely moved away from this practice. For the few complacent operators, does it really seem the best move is to create more stringent regulations or rather, perhaps discontinue the use may be a better option? Why create more stringent operations for the few rather than discontinue and commence with above ground storage structures as the more responsible operators have done? Above ground storage structures are a superior choice with consideration to adequately protecting our water resources and knowing the damage that pits can create. Nearby residents need to be protected from second best operations when there are better, more community friendly, more environmentally friendly options available. Regulations serve the floor of requirement for some operators that are otherwise complacent.

78.57. Control, storage and disposal of production fluids.

78.57(a)(b) C.O.G.E.N.T. supports the elimination of the use of pits and the use of a series of pits as used for the collection of brine and other fluids. C.O.G.E.N.T. supports measures that provides for more stringent requirements for the storage of brine and other fluids eliminating the use of open top storage. The *STRONGER Pennsylvania Follow-Up State Review* published September 2013 notes that *"The DEP's current regulations in 25 Pa.Code §§ 78.56 and 78.57 are limited with regard to requirements for location, use, capacity, age and construction of E&P waste tanks."* Further, the *Review* states, *"The review team has determined that a large number of tanks exist throughout Pennsylvania and that the state does not have standards for tank closure and removal."* And finally, the *Review* states, *"The review team finds that the DEP consider adopting regulations that address tank inventory, structural integrity, siting, the use of open top tanks, secondary containment, tank security and removal." [page 39] (Guideline Section 5.9.2.)* We appreciate the Department moving forward with action that implements recommendations from the STRONGER *Review*. Pursuing action based on the STRONGER *Review* is one important aspect of addressing regulations in an organized and fluid manner. We support the adoption of these provisions at a minimum as written.

78.57(c) (includes Conventional Drillers)

The Commonwealth's extraordinary amount of water resources is only surpassed by the much larger state of Alaska. Many of us fully didn't recognize the quantity of water resources all around us until we began noticing in the early years of Marcellus Shale that it almost seemed more common than not to have a well pad located nearby a pond, small stream, creek, wetland, river or some other water body. In order to fully protect our water resources, environmental protection has grown towards the use of secondary containment in many industrial facilities. It is time to implement the use of secondary containment for all aboveground structures which hold brine or other fluids. We realize that the legacy of these structures is primarily a liability of the conventional drillers, whom at times have been complacent to move forward and utilize modern environmental protection methods. According to the

regulatory analysis, on a per well basis, this additional cost to the conventional drillers is $3,000. Given the fact that oil prices/barrel have continually been hovering around $100, it does seem the time is right to finally address these potential environmental risks. We therefore, support this provision for adoption at the minimum as it is written.

78.57(d) C.O.G.E.N.T. recommends the adoption of this provision which creates design standard for tanks and above ground storage structures.

78.57(e) (includes Conventional Drillers)

We hereby emphasize our support for **78.57(e).** We recognize that this provision mainly pertains to conventional drillers. With the advent of conventional horizontal drilling, it is of significant importance that attention be paid to underground or partially buried storage tanks. It is unclear at this point how conventional horizontal drilling will affect the conventional driller's operations.

It is well documented that underground and partially buried storage tanks create greater environmental risks than above ground storage tanks with secondary containment. Providing operators with a three year time frame provides them with adequate opportunity to do appropriate and needful business planning. Many of these tanks are very old. They are subject to weather and seasonally changing soil conditions and thus corrosion. The environmental harm that may be created by old and leaky tanks far outweighs the replacement cost.

Considerable discussion occurred during the TAB subcommittee meeting regarding removal and replacement of these tanks. There was not sufficient, factual information put forward that effectively demonstrated why these tanks need not be removed. During the meeting it was suggested that a certification of discontinuation of use should be accepted in lieu of tank removal. This is not acceptable. In cases where former gas stations have ceased operations, tanks most often are removed. Often, upon removal of these old tanks it is discovered that they had been leaking.

Filing certificates for dotted fields of abandoned "tank litter" is not an acceptable environmental practice.

The September, 2013 STRONGER review noted that there may be as many as 200,000 tanks currently in statewide. *"The review team has determined that a large number of tanks exist throughout Pennsylvania and that the state does not have standards for tank closure and removal.* They further recommended that *the DEP consider adopting regulations that address tank inventory, structural integrity, siting, and the use of open top tanks, secondary containment, tank security and removal." (Guideline Section 5.9.2.)[page 39]* Much of what is proposed here meets that recommendation.

We support the recording initiative that will essentially create a partially underground and buried tank inventory. We strongly urge the adoption of this provision with the intent as it is presently written. This provision aids the Department in ensuring that our environment, especially that our water resources are adequately protected.

78.57(f) Corrosion is an important factor with both the tanks and the brines and other fluids that may be stored. C.O.G.E.N.T. recommends the adoption of this provision as written.

78.57(g) Landowners are concerned about third parties gaining access to sites and tank areas. Tanks may contain a variety of substances that in the event of an authorized action may place at risk our water supplies or even nearby properties. C.O.G.E.N.T. recommends that these security measures and all others be adopted in order to provide for adequate protections for our water supplies and properties.

78.58. [Existing pits used for the control, storage, and disposal of production fluids.] <u>Onsite processing.</u>

This provision was discussed at length at the TAB subcommittee meetings this past summer. We are supportive of recycling efforts, as they greatly benefit our community, environment and the industry. Industry suggestions during the TAB subcommittee meetings regarding the duration of on-site processing at well sites in many cases near our homes, schools and perhaps hospitals provide us with concerns. These concerns are not without substance. The MAZZARRA site, Washington Township, Wyoming County during 2013 had a 9,000 gallon spill of treated flowback water that was contained in a basement of a nearby home. That is not proper secondary containment. North Dakota has had a number of brine spills just in the recent months alone. We need to be adequately prepared so we can avoid these situations.

It is important to note, that while these are temporary onsite processing facilities, with the long-term view and fluctuations in drilling due to a variety of reasons, centralized WMGR123 facilities are the preference. Regulations need to encourage the use of these facilities over the temporary on-site processing.

We want to be clear, whatever the end result that facilitates the industrial onsite processing, equal consideration needs to be given to locations where there are nearby homes, schools or hospitals. This is imperative in locations where there are no local ordinances that would supply basic guidelines providing nearby residents measures that would extend to them being comfortable within their homes. Thus, as an attempt to provide a pathway towards reaching that delicate balance where all may thrive, we offer these recommendations on this section.

- As proposed, these sites are somewhat different than either the OG-071 or WMGR123 facilities. In the case of 78.58, we recommend that the

Department develop two new permits and a corresponding guidance document.

- The first permit is the EZ permit. These are facilities located either at an adjacently expanded area to a well site to accommodate processing or on an existing well site. Regardless, in either case, the distance from the edge of the pad or expanded area to the nearest occupied dwelling is 1500' or greater. This is a more isolated location and thereby processing is more respectful towards the community and local impact. We need to give the industry an incentive to make better location choices. This is a way of achieving that goal. These are intermittent facilities. These locations the operator obtains a one year permit. With a minimum of nine months of absence or no activity, they can apply for a renewal for another year period. In that fashion, they can renew the permit up to two times, facilitating a total of 3 years of processing at that location. This provides sufficient opportunity to service wells nearby.
- The second permit is a restricted permit.
    - This permit is only issued for locations that are less than 1500' from the nearest occupied dwelling. There are cases where well pads have been sited too near homes and have resulted with unreasonable local impacts to the nearby neighbors. Often, it is these same cases where municipalities lack local zoning and planning. It is even more likely that these same municipalities will not address planning and zoning for a number of localized reasons, one being it may be very few families affected. However, the fact remains that well sites are located too near some homes and the impacts are unreasonable in terms of intolerable noise and at times air quality issues due to diesel exhaust fumes. Since there is a regulatory opportunity here, we are recommending that the opportunity be taken. If the operator is able to obtain waivers from all the neighbors within the 750' then they do not have to do the required mitigations as outlined below.

- This permit is a one-time temporary permit, three months with an option for a three month renewal. However, in the case of the neighbor's waving the mitigations, for the three month renewal the operator will need to obtain renewal waivers from all occupied dwellings within the 750'. This is to provide the neighbors with the opportunity to have mitigations in place now that they've had the experience, and perhaps an unreasonable impact.
    - Due to variations in topography, temperature, season and localized wind patterns there is a variety of experiences in which noise and air quality impacts affect the nearby neighbors. There are cases where homes at a 300' distance from a well site are not that inconvenienced. On the other hand, there are cases where a 500' distance is not adequate. It is not unusual for the nearby homeowner to not have had any contact with the operator regarding the site location since it is not located on their property, but rather on their neighbor's property. Generally, only the landowner where the well site is located had input into the well site location. It is clear that in some cases, based on experienced localized impact, neither 300' nor 500' distance is adequate. Now, there is a necessity to do more industrial activities on these sites that in some case may not be such a desirable location in regards to impacting the nearby neighbors. We are not opposed to the activity, but rather we desire to address impacts in such a way that all may thrive. This is the exact reasoning for these two options.
    - Notification – this is a different type of facility. Neighbors within 750' need to be given a notice that the permit is being applied for, what the facility is, and a contact person – name & phone number to contact in case of a problem. Presently, not all operators return calls of their neighbors. A neighbor may have a legitimate need to contact them. For example, in case of

too much idling diesel traffic and the result is they are having air impacts inside their home. This situation has been experienced the gas fields and it is one that an operator can handle with proper vehicle queuing. They may not necessarily know what is happening in the field lacking that phone call from an impacted neighbor. Included in this mailing is a fact sheet created by the Department that outlines noise and lighting impacts and available mitigations. The fact sheet also outlines the waiver process.

- Lighting – needs to be respectful of the neighbors. The lighting needs to be directed on the facility not a thousand feet to the neighbor's homes. Some operators are employing the use of Lunar Lighting while many are not. Lunar Lighting is an emerging technology in the oil and gas fields, in fact, as you can see here, http://www.texasoilgasmagazine.com/conferences-expos *The **Texas Oil & Gas "Emerging Technologies" Conference & Expo** will bring together industry experts who will discuss the emerging technologies, processes, and applications utilized in the Oilfield in Texas. The Conference Experts will speak about the developments that are evolving in the Mid-Stream, Up-Stream, & Down-Stream areas of the Oil & Gas Industry. Some of the topics covered will be Lunar Lighting, CNG Fleet & Commercial Vehicles, LNG: A Sustainable Energy Resource, HSE Training, and many more to come. Learn about the Challenges and How Effective Utilization of these Technologies can result in being more profitable and effective in the Industry. Visit the Expo to talk to Experts that are bringing in their latest technological advances to showcase for attendees. Network and build lasting relationships that will expand your marketplace and bring businesses together! You will want to be here at the Epic Conference and Expo of the Year!*

  Event Name: 2014 Texas Oil and Gas "Emerging Technologies" Conference & Expo
  Date: October 14-15, 2014
  Venue: Reliant Park, Houston, Texas
  Organizing Company: 4 X-Stream Media, Inc
  Contact Person: Leah Terry, Conference Director
  Contact Number: 210.853.0213 210.284.1231

Email: ***LeahTerry@TexasOilGasMagazine.com***

- Other resources on Lunar Lighting:
  - http://www.lunarlighting.com/
  - Youtube: http://www.youtube.com/watch?v=DmxWapYVuKs
  - http://www.azomining.com/equipment-details.aspx?EquipID=135
  - http://www.forconstructionpros.com/product/10764486/lunar-lighting-pty-ltd-lunar-lighting-tower

When operators choose to establish sites in close proximity to homes, within 750' they are simultaneously choosing to mitigate their impacts in every possible way to ensure that the neighbors are comfortable within their homes and that our rural and agricultural integrity remain in place. The fact is that operators have determined most often to comply with local ordinances at a minimum, or have not taken any steps towards mitigation regarding either lighting or noise issues in communities where there are no local ordinances. If the Commonwealth of Pennsylvania is going to be a leader in a world class shale gas play, then the operators need to be functioning as world class, appreciating and respecting the communities where they operate regardless of whether local ordinances exist. We know from experience that we are not able to be effective with every operator 'doing it right' every time. Therefore, the Department needs to create a basic floor of regulations that consider those whom now dwell within 750' of well pads and facilities and have experienced unreasonable impacts related to such issues as lighting and noise. The zoned communities may choose to build upon these mitigation regulations, but nevertheless, those that dwell within non-zoned communities still deserve and need these basic and reasonable mitigations should their municipality or county fail to act upon doing so.

- Noise – it is difficult to assess what types of noise beyond traffic may be created by a temporary waste fluids processing facility. We note that C.F.R. has a basic and reasonable regulation that applies to drilling, and in reality, should also apply to drilling and fracturing well sites in Pennsylvania. The regulation we refer to is C.F.R. Title 18, Chapter I, Subchapter E, Subpart F, 157.206 Standard Conditions (b)(5)(iii) ***Any horizontal directional drilling or drilling of wells which will occur between 10 p.m. and 7 a.m. local time must be conducted with the goal of keeping the perceived noise from the drilling at any pre-existing noise-sensitive area (such as schools, hospitals, or residences) at or below a night level (L_n) of 55 dBA.*** This may require the operator to erect a temporary, portable sound barrier or sound curtain. There is a Pennsylvania based company that offers such services. Oeler Industries, Inc. offers portable sound barrier products that may be used in both drilling and fracturing sites. Their products would also be useful at temporary waste fluids processing sites. When such products are indeed available, the neighbors need to be considered. The operator needs to do such mitigations. The fact of the matter is the operator chose the well site location, and they will be choosing the temporary waste fluids processing location. When they choose to operate within 750' of occupied dwellings, they have determined in the same mode to utilize noise abatement technologies. The Department needs to protect the environment of the neighbors who live within 750' of an active site. More information on Oeler Industries may be found here:
    - http://www.marcellusnoise.com/
    - http://www.marcellusnoise.com/fracking.html
    - http://www.marcellusnoise.com/drilling.html

- Volume – there needs to be a maximum processing volume attached to the permit to avoid these from becoming the size, scope and activity of a WMGR123 facility.
- Leak detection – we recommend the operator perform daily visible inspections and employ leak detection technologies along with secondary containment. Secondary containment requirements need to be consistent with the Department's most stringent and effective tank secondary containment requirements.

- **78.58(a)** We recommend that the permit specifically require that the processed fluids be either generated at the site or are intended to be used at the site.
  - We recommend that recordkeeping be involved in order that fluids are tracked. For example, in cases where fluids are generated at the site, there is recordkeeping of where the fluids are taken/used. In cases where the fluids are transported to the well site for use there is recordkeeping detailing the source of the fluids. This information needs to be interfaced with the Department's wastewater tracking system.
- **78.58(b)** Activity approval – these are standard processing operations. Any are suitable under these prospective permits.
- **78.58(c)** Process of drill cuttings – We are agreeable to the processing of cuttings at the well site.
- **78.58(d)** Residual waste – We are agreeable that the processing of generated residual waste shall comply with the requirements of the Solid Waste Management Act, including waste characterizations.
- **78.58(e)** Ease of operation – We recommend that two new permits be created for onsite processing at temporary locations as has been outlined above. Any effort the Department may make to do electronic permitting to assist the industry is reasonable. It is also reasonable that the public be able

to access this information online rather than have to do an in-person visit to the regional office.

- **78.58(f)** Characterization of waste – During the TAB meetings, the industry questioned the number of characterizations to be completed. One per well, or per truck; also noted was the time lag in obtaining the results and the transporting of the waste. They had discussed transfer stations, and one member of the public noted that present transfer stations were not working well in their county. Thus, this needs to have further discussion. There needs to be more information provided – what are the current characterizations indicating? Lacking this information, we recommend the Department err on the side of more stringent rather than less in the number of required characterizations. Concerning the time lag, that needs to be considered with the characterizations. It may be possible to pull all the samples as the solid waste is accumulating such that by the time the results are available the waste is ready to be hauled out. That may eliminate the need for a transfer station. Another option would be to ensure the temporary processing site is large enough to contain the waste until the waste may be hauled. Finally, the Department could review the appropriateness of transfer stations and possibly develop yet one more permit and guidance for such a location.

We respectfully request that the Department give careful consideration to our recommendations noted above. We desire that more consideration be given to those that dwell within 750' of well site locations. This is a first step in doing so. We are very seriously engaged in advocating the attainment of a delicate balance that allows all - public health and safety, community, the environment and the industry, to thrive. The flexibilities we have built into our recommendations create that opportunity. With consideration and adoption of our recommendations, we are able to support this provision.

78.59a. Impoundment embankments.

The industry has a huge need for water. Our rural, farmland and forested communities benefit from impoundments where in some cases due to freshwater withdrawal directly flowing freshwater lines, inbound water hauling may be eliminated from our roads. This greatly improves traffic congestion and air quality issues related to heavy diesel traffic. Impoundments also provide a storage component for the industry providing opportunities to store water for use during the seasonal low water periods when they may desire to fracture wells and many water withdrawal locations may be placed on pass-bys. C.O.G.E.N.T. fully supports the impoundment embankment standards and recommends their adoption at a minimum as is written.

78.59b. Freshwater Impoundments.

78.59b.(b) We recognize and appreciate the Department's effort to create an inventory of existing freshwater impoundments. While some counties such as Bradford County have done an excellent job in mapping Marcellus Shale infrastructure, that is not true of all counties. The Department recently introduced a new mapping system, and ideally all oil and gas infrastructure, including impoundments and compressor stations etc. need to become part of that mapping system. Achieving such a statewide mapping will provide an accurate resource for counties that have not created current mapping of facilities. Ideally, we'd also like to see an as built gathering line layer available. Many operators would willingly provide such valuable information to the Department. It will also assist those that dwell within the gas fields to have access to information concerning their changing rural, farmland and forested communities. We are also glad to see the Department recognizing the transfer of impoundments as we do know such cases have already occurred.

78.59b.(c) (e) (f) We support these well needed construction and restoration provisions. As the industry continues to expand in our region, impoundments are

an integral part of the development infrastructure and therefore construction and restoration regulation are necessary to adequately protect our water resources.

78.59b.(d) We are concerned about unauthorized individuals gaining access to the many sites located within our region. Landowners have been dismayed by third parties trespassing on well pads and impoundments fully knowing that such locations may be dangerous for the general public. Landowners have not readily understood why it is that some consider it their prerogative to not only trespass on their lands but also, an industrial work site at that. Landowners also have concerns about a variety of third party damage issues some of which have occurred that resulted in environmental damage on their property. Such an occurrence was recorded in March, 2012 regarding a spill of diesel fuel at a gas well in Bradford County's Springfield Township, Houseknecht 3H well site. Ten to Twenty gallons of diesel fuel were found in a farm field around the well, and some was discovered in a nearby unnamed tributary. In our region, where agriculture does continue to play a role in our regional economy, and includes organic producers, unauthorized third party access is an important concern. [http://www.stargazette.com/apps/pbcs.dll/article?AID=2012203090398] Therefore, we fully support the fencing provision at a minimum as it is written.

78.59b.(g)

We support the use of AMD in fracturing operations. When storing mine influenced water in a freshwater impoundment, we do have some concerns. We do not want to create new environmental issues created due to inadequate handling of MIW in freshwater impoundments. Frankly, we are concerned about AMD leaking into areas that are not historical coalfields where such pollution would be a new point source. We do agree with the testing of MIW at its source along with the record keeping component. Raw AMD, MIW of necessity must not be stored in a freshwater impoundment lacking testing that indicates that there is no contamination risk to nearby water resources. It is reasonable to store AMD, MIW in freshwater

impoundments near the source as it would not create a new environmental problem considering the historic nature of the location.

According to the definition of freshwater impoundment, the FWI is designed to only contain fluids such as surface water, ground water and other Department approved sources. Our only concern is that in consideration of AMD and MIW a reliable standard is applied that sufficiently and adequately protects our water resources in the event the FWI succumbs to unintended leakage. We also desire that appropriate consideration be given to the seasonal high groundwater table as indicated. We request that the Department consider our concerns with the aspects of this provision.

78.59c. Centralized Impoundments.

As a better environmental and community friendly practice, we support the use of modular above ground containment structures rather than centralized impoundments. We prefer the use of 100% closed loop systems whereby all fluids are appropriately contained in a manner that eliminates risks to public health and safety and the environment. There are operators that recycle, such as Cabot, who recycle 100% of their fluids without the use of centralized wastewater impoundments. We are not aware of any recent permits for centralized wastewater impoundments by another large operator in our region, Chesapeake Energy.

These provisions are most needful indeed. We support the requirements of monitoring wells, secondary liner and a leak detection system. We are however, concerned about operator's inadequate attention paid to the leak detection system and the opportunity to recirculate leaked fluids rather than correct the problem. The leak detection system actively engaged must be the exception not the daily method of operation. We are also concerned that the Department may not have adequate staffing to maintain as close an eye as may be necessary to such facilities due to the recirculation issue. The field staff generally is focused on the sites of action, drilling and fracturing, and rightly so. Often the CWI is located off the focus

of risk activity, thus a leak detection system engaged and not regularly inspected by the Department may provide the operator with opportunities to be complacent rather than actively concerned about the environment in which they operate. After all, it is the same operator who is choosing to use antiquated centralized wastewater impoundments as opposed to 100% closed loop systems. This is not to imply that these standards are antiquated, as they are in part at least currently recommended construction practices being codified. To be clear, what we do mean is that the concept of CWI is a method of the old ways. This is a world class shale play as has been pointed out many times. We, the residents whom live near such facilities, deserve them to be world class as well, and thus, 100% closed loop systems are the preferred practice.

While we are in support of these provisions, we also note that there are better practices utilized by many unconventional operators and therefore, we prefer to see the industry be encouraged to move away from this practice through regulation. There is one operator, Southwestern, [OHara Centralized Wastewater Impoundment, SWN, Jackson Twp, Susquehanna County, Permits 95-29-65420-021 and ESG13-115-0126] that we are aware continues to apply for permits for such facilities in our region. There are other operators across the state, such as Range Resources who are complacent in not moving towards better technology than these CWIs. This practice, in terms of shale gas and the great strides that have been made in our Commonwealth since the drilling began with a variety of technologies can be considered an antiquated process. We advocate that all CWIs at a minimum be evaluated and where deficient, be upgraded to meet these provisions or the CWI be closed. Ideally, we prefer to see the practice of CWIs cease in practice. When most operations are not utilizing these facilities, it makes sense to create more stringent requirements as are noted here, and move towards creating a level playing ground where public health and safety and the environment is equally considered by all operators with such facilities.

Generally, operators have definite terms with landowners as to the longevity of the agreement, such as ten years for example. We recommend that the landowner be provide with a fact sheet/information prior to the renewal of such an agreement that explains alternative procedures that may be employed to reach the same goal, and that is the processing of waste water. An informed landowner may prefer to have the impoundment location converted into a facility with aboveground storage containment or a series of tanks which provide for superior environmental protection. Generally, in more recent times, CWIs have been permitted with reference to servicing specifically named gas wells. We urge the Department to review the CWI inventory for where this information may be lacking and require the operator to provide such information. We urge the Department to create a linking database in order that once the named wells have been placed into production, that the CWI be restored to its prior land use/function. In the event the Department is unable to completely prohibit the CWI practice, we urge that a gradual phase out be initiated. In the view of adequately protecting water resources, it just makes no sense to allow this antiquated method to continue when closed loop and superior aboveground containment systems are fully capable of processing and storing large quantities of water with less environmental risk to our water resources, public health and safety and the environment. We request that the Department consider our concerns with this provision. We request as a better protection the elimination of CWIs, but at a bare bones minimum, reluctantly recommend the provisions as written.

78.60. Discharge requirements.

We fully support the inclusion of Chapter 105 requirements in conjunction with proposed provisions regulating CWIs. This includes the referenced definition in 105.1 for watercourse which is consistently applied in this proposed revision. We therefore, recommend this provision for adoption as presented.

78.61. Disposal of drill cuttings.

This provision deals directly with drill cuttings that are generated at the well site from above the casing seat and disposed into pits. With the precautions that are provided for as part of the casing and cementing plan §78.83c the cuttings may be disposed of in a pit at the well site providing they are not contaminated with a regulated substance as detailed and the disposal is not within 100' of a watercourse as noted in the language change. As noted above, and throughout this entire rulemaking, we support the definition of watercourse as noted in Chapter 105.1 as it lends to consistency across the regulations.

In regards to drill cuttings that are generated at the well site above the casing seat which are not contaminated with any regulated substance and the disposal is not within the stipulated setback of a watercourse or water supply providing they meet all other requirements such as removing the liquid fraction, etc. a land application is reasonably suitable. The new provision, which provides for a soil ratio along with the requirements of not spreading in saturated, snow covered or frozen ground lends success to an environmentally sound land application disposal method.

Finally, for drill cuttings generated at the well site from below the casing seat, where such waste is considered residual waste, it is necessary to take a closer look into what this actually means in concert with the quantity of cuttings generated and the environmental practice of safe and responsible disposal methods. These are contaminated drill cuttings that may qualify for both disposal as residual waste in pits or land application at the well site. The proposal is to create an approved listing of solidifiers, which certainly makes the process easier for both the Department and the operator. The proposal also provides for a three day advanced notification prior to disposal which may allow for adequate planning for the Department's staff to be onsite and perform an inspection of the work. Standing alone, those two provisions are both reasonable, and therefore, we do recommend both provisions for adoption. These two options are further proposed in sections 78.62 and 78.63. Our specific comments on these follow.

78.62. Disposal of residual waste – pits.

After the liquid fraction of the drill cuttings is removed, residual waste, including contaminated drill cuttings may be disposed of in pits providing the drill cuttings were generated on that specific site. Excluded from this disposal method is solid waste generated by hydraulically fractured unconventional wells and also, fluids processed in accordance to 78.58. The volume and contaminants make it very impractical to even consider onsite disposal for hydraulically fractured unconventional wells generated solid waste and fluids processed in accordance with 78.58. We therefore, fully support and recommend prohibiting site disposal of solid waste generated by hydraulically fractured unconventional wells and also, fluids processed in accordance to 78.58 as written.

78.62(a)(1-4,6-8,10) The changes here reflect the addition of residual, stimulation and references to Act 13, all which are needful. We therefore, recommend their adoption at the minimum as is written.

78.62(a)(5) The proposal also provides for a three day advanced notification prior to pit disposal which may allow for adequate planning for the Department's staff to be onsite and perform an inspection of the work. Therefore, we do recommend both provisions for adoption.

78.62(a)(9) While this provision is less detailed than a similar provision, 78.59b.(e) the required certification statement ideally will ascertain that the environment and specifically our water resources will be adequately protected. However, we suggest that just as in 78.59b.(e) this statement be part of this provision as well: *In no case shall the regional groundwater table be affected.* With this additional consideration we recommend this provision for adoption.

78.62(a)(11-18) The codification of pit construction standards that mirror those for temporary storage creates standard regulations for all pits, temporary and

permanent. All pits, whether temporary or permanent need to be constructed to the most rigorous and modern standards in order to adequately protect our water resources. We support that standardization for adoption.

78.62(b) This provision provides that residual waste not exceeding certain contaminate concentration levels may, while still contaminated be disposed of in an onsite pit. This pit of course meets these better construction standards, but nevertheless, we are considering the burial of contaminated residual waste. It is perhaps important to consider a few items. As noted on the Drilling Waste Information Management System, *"Onsite pit burial may not be a good choice for wastes that contain high concentrations of oil, salt, biologically available metals, industrial chemicals, and other materials with harmful components that could migrate from the pit and contaminate usable water resources."* [http://web.ead.anl.gov/dwm/techdesc/burial/index.cfm]

In regards to those contaminated residual wastes that do qualify for onsite disposal, we do have some concerns. Our concerns pertain to potentially larger volumes of cuttings per site relative to the upcoming technology change to conventional horizontal wells, and in the rare event, to those unconventional wells where such wells are not hydraulically fractured. The Department needs to view this with an eye to the future of a possible increase of conventional drilling. The renaissance of exploration may extend in a greater way to conventional drillers in the future. The price of oil is higher than in many years and a new operator, IMG Midstream is offering a new opportunity in the unconventional fields which they are now interested in applying to the conventional gas fields. *"In planning the projects, IMG found that the same constraints that stifle conventional gas producers' getting their product to market also apply to Marcellus companies. So, now, the company plans to source from both conventional and shale producers."* http://www.post-gazette.com/news/state/2014/01/08/IMG-Midstream-plans-small-plants-to-generate-electricity-from-gas/stories/201401080079
This new opportunity, distributed energy, is one whereby field gas is transported to a facility and through CHP electricity is generated and via the nearest substation

enters the electric grid. So, we are considering this with two viewpoints, one that conventional horizontal drilling may create per site a greater quantity of residual waste and distributed energy may increase drilling in the conventional gas fields. Thus, we are considering the possibility of an increasing load of contaminated residual wastes and whether it is appropriate to continue with onsite disposal.

PA Code 288 Residual Waste Landfills creates application and operating requirements for three specific kinds of landfills, Class I, Class II, and Class III. Application requirements include site analysis, cover and re-vegetation, water protection and monitoring, and closure provisions. Granted, oil and gas residual waste disposal pits are significantly smaller, but in consideration of small landfilling of contaminated residual wastes, it is appropriate to review what if any oversight may be missing as compared to a regulated residual waste landfill. For example, as part of the site analysis, the applicant is required to sample and describe certain characteristics of the aquifer for at least two quarters, including concentrations of arsenic, barium and lead. The applicant also has to provide a water quality monitoring plan. Upon closure of the facility, the applicant is required to provide a schedule of ongoing post-closure water quality monitoring, leachate collection and treatment, along with a description of the manner in which funds will be available to cover these and other required conditions.

We are concerned about the manner in which materials leaching may not be monitored in so many well site pit locations. We are concerned with the lack of oversight as compared to a regulated residual waste landfill, how likely it is that rural private water supplies may be impacted, and if so, the seriousness of such impacts and how the impacted homeowner's water supply will be remediated. In addition, it is important to note that in general, conventional drillers are much smaller operators than unconventional. Many notable conventional drillers of years gone by such as Pennzoil Prod. Co. has not spud a well in Pennsylvania since 2007. Many other less known operators have also ceased their activity in Pennsylvania. Thus, our concern lies with what happens in the long-term obligation when a

contaminated residual waste pit has unnecessarily impacted a water supply, whose obligation/liability does it then become? Again, we are really focused on the disposal of contaminated residual wastes and what that means in regards to onsite well disposal methods.

Clean Earth of Williamsport currently has a Beneficial Use R&D permit [WMGR097R017] *to demonstrate that drill cuttings and drilling mud generated during Marcellus Shale operations can be successfully processed and beneficial used as engineered fill at brownfield or Act 2 sites, as a construction material at other sites, and in construction of drill pads.*

http://www.pabulletin.com/secure/data/vol41/41-21/853.html

REGISTRATION UNDER RESIDUAL WASTE GENERAL PERMITS

Application(s) for Registration Received Under the Solid Waste Management Act (35 P. S. §§ 6018.101—6018.1003); the Municipal Waste Planning, Recycling and Waste Reduction Act (53 P. S. §§ 4000.101—4000.1904); and Residual Waste Regulations for a General Permit to Operate Residual Waste Processing Facilities and/or the Beneficial Use of Residual Waste Other Than Coal Ash

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Central Office: Division of Municipal and Residual Waste, Rachel Carson State Office Building, 14th Floor, 400 Market Street, Harrisburg, PA 17105-8472.

General Permit Application Number WMGR097R 017. Clean Earth, Inc., 334 South Warminster Road, Hatboro, PA 19040. The application is for a research and development project designed to demonstrate that drill cuttings and drilling mud generated during Marcellus Shale operations can be successfully processed and beneficial used as engineered fill at brownfield or Act 2 sites, as a construction material at other sites, and in construction of drill pads. The processing is limited to addition of a drying agent, such as Portland cement, cement kiln dust or sawdust to the drill cuttings or drilling mud. The proposed Clean Earth, Inc. processing facility is located at 212 Colvin Road in Williamsport, PA. The application for registration was deemed administratively complete by Central Office on May 9, 2011.

Comments concerning the application should be directed to Scott E. Walters, Chief, General Permits/Beneficial Use Section, Division of Municipal and Residual Waste, Bureau of Waste Management, P. O. Box 8472, Harrisburg, PA 17105-8472, 717-787-7381. TDD users may contact the Department through the Pennsylvania Relay service, (800) 654-5984. Public comments must be submitted within 60 days of this notice and may recommend revisions to, and approval or denial of the application.

On December 19, 2013 Penn State Extension hosted a webinar *"Drilling and Pipeline Cuttings Reclamation"* which provided an update regarding the progress made with the Beneficial Use Permit.

http://extension.psu.edu/natural-resources/natural-gas/webinars/drilling-and-pipeline-cuttings-reclamation/drilling-and-pipeline-cuttings-reclamation-powerpoint-december-19-2013/view

This is a very informative webinar, just full of interesting facts. One item that is mentioned is that *"The 10% not suitable for reuse exhibited the following characteristics: 1) (Naturally occurring radioactive material, norm above background) and 2) Inorganic constituents such as Arsenic, Lead, and Barium."* Because these cuttings are not suitable for reuse, their destination becomes a landfill that is properly authorized to accept contaminated drill cuttings. To be clear, we do understand that these are cuttings from both vertical and horizontal bores and strictly unconventional drilling. Thus, while these cuttings may be from deeper depths than the conventional residual waste contaminated cuttings referenced in this section, still, some of the contaminated cuttings may essentially come from shallower formations. Other contaminated substances that may be disposed of in the onsite pit are items other than the cuttings such as drilling muds and thus a soil component. Thus, there is good information here that we can at least compare to 40 C.F.R. 261.24 Table I (relating to the characteristic of toxicity). Arsenic, Lead and Barium are all constituents of unconventional drill cuttings and noted contaminants on Table I. These same contaminants may be common to conventional drilling and are contaminants that are of concern regarding residual waste landfills in PA Code 288.123.

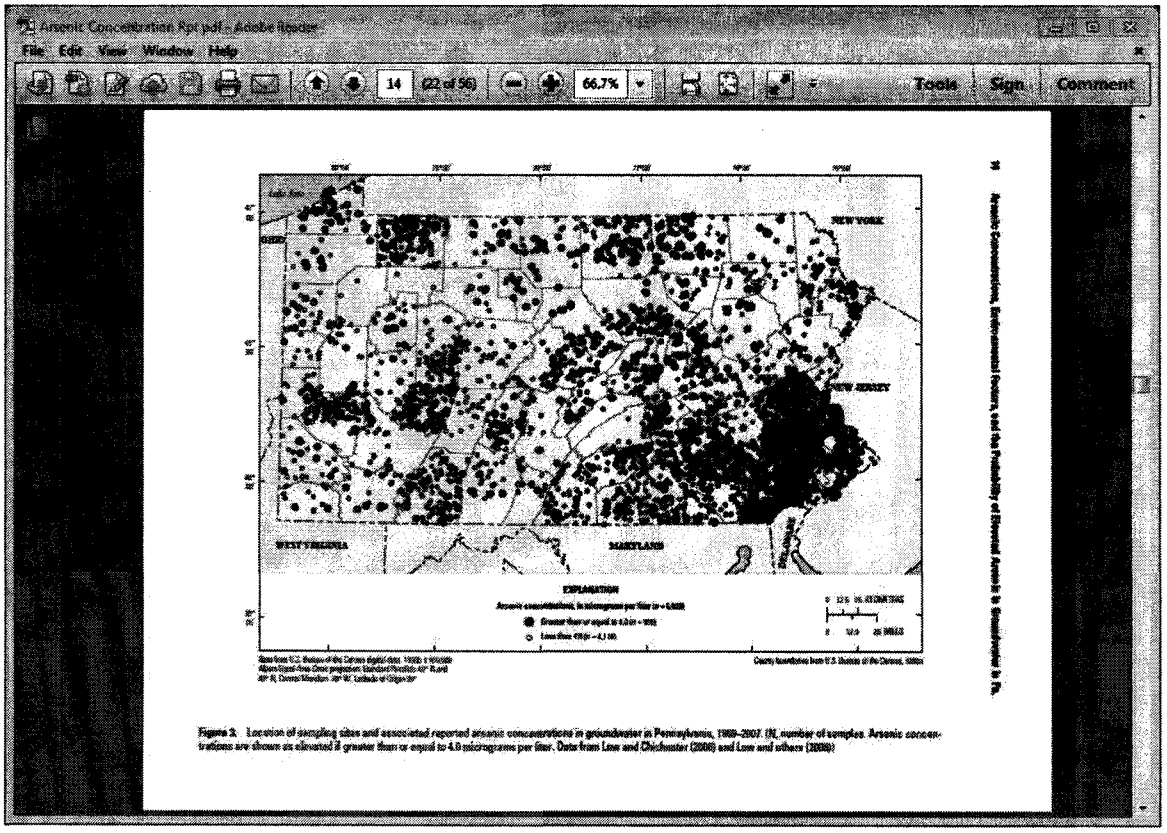
It is worthwhile to consider the presence of these same contaminants in conventional drilling onsite disposal. Here follows a discussion regarding arsenic as an example.

Arsenic – [Source: Drinking Water Quality in Rural Pennsylvania and the Effect of Management Practices 2009 , The Center for Rural Pennsylvania http://www.rural.palegislature.us/drinking_water_quality.pdf p8, 12 , 13, 18, 19
Source: Fact Sheet - Arsenic in Ground Water Resources in the United States http://pubs.usgs.gov/fs/2000/fs063-00/fs063-00.html#HDR2 Last modified: Wednesday, January 09 2013, 07:57:00 PM
Source: High Arsenic Levels Found in 8 Percent of Groundwater Wells Studied in Pennsylvania http://www.usgs.gov/newsroom/article.asp?ID=3564#.Uw0HZfldXpV **Released:** 4/17/2013 9:00:00 AM]

- Water samples collected indicated a presence of arsenic. *"Arsenic is a relatively new concern in drinking water with serious health effects at very low concentrations. It is thought to most often occur naturally from certain types of rocks but it can also come from treated lumber and pesticides."*
- Only 2 percent of the wells exceeded the health-based drinking water standard of 10 mg/L for arsenic. The maximum concentration observed was 35 mg/L but the majority of wells (89 percent) had arsenic concentrations below 6 mg/L. Wells with high arsenic occurred mostly in northern Pennsylvania regions, presumably due to the geology of these areas. The three northern regions of the state had significantly higher arsenic concentrations than the southern regions with the highest occurring in the northwest region. These results are similar to results reported by the U.S. Geological Survey (2000) for 578 private wells that were sampled in southeast and extreme western Pennsylvania. Arsenic is thought to originate primarily from natural geologic sources, thus, it would not be expected to vary significantly over time.
- Contamination of private wells can occur through the interaction of both natural and human causes. Leaching of arsenic from bedrock is an example of a natural source. Leaching from an oil and gas waste pit is an example of human causes.
- The well owners that participated in this study were made aware of problems that occurred in their water supply. .... Note that the percent avoiding water quality problems increased dramatically in each case. Pollutants with more severe or better documented impacts on human health, like lead, arsenic and E. coli bacteria, had the highest avoidance rates at the

end of the study. .... Since relative risk information was given to each well owner in the Penn State Cooperative Extension fact sheets included with each water test report, it is not surprising that well owners responded with greater actions for pollutants with greater risks.

- Arsenic is also a human health concern because it can contribute to skin, bladder and other cancers (National Research Council, 1999).
- The National Research Council (1999) recommended lowering the current maximum contaminant level (MCL) allowed for arsenic in drinking water of 50 μg/L (micrograms per liter), citing risks for developing bladder and other cancers. The U.S. Environmental Protection Agency (USEPA) will propose new and likely lower, arsenic MCL during 2000 (U.S. Environmental Protection Agency, 2000). This fact sheet provides information on where and to what extent natural concentrations of arsenic in ground water exceed possible new standards.
- As the concentration for a possible new MCL decreases, the likelihood of exceeding that standard increases. Although homeowners with private wells are not regulated, a lower drinking-water standard would mean that more homeowners will be consuming water with concentrations that exceed a standard.



Source: http://pubs.usgs.gov/sir/2012/5257/support/sir2012-5257.pdf

Figure 3. Location of sampling sites and associated reported arsenic concentrations in groundwater in Pennsylvania 1969-2007. (N, number of samples. Arsenic concentrations are shown as elevated if greater than or equal to 4.0 micrograms per liter. Data from Low and Chichester (2006) and Low and others (2008))

- On the above map, reported arsenic concentrations in Pennsylvania groundwater are noted not only in the Northern Tier Region, but also across the vast Marcellus Play including, areas that are also locations prone to conventional/shallow oil and gas drilling. These are same areas where folks rely on private water sources, wells and springs. These are the same locations where contaminated drilling cuttings may be disposed in pits.

- *"This research is not intended to predict arsenic levels for individual wells; its purpose is to predict the probability of elevated levels of arsenic in groundwater to help public health efforts in Pennsylvania," said USGS scientist Eliza Gross, who led the study. "The study results and associated probability maps provide water-resource managers and health officials with useful data as*

they consider management actions in areas where groundwater is most likely to contain elevated levels of arsenic."

The Pennsylvania Department of Health plans to use the maps as an educational tool to inform health professionals and citizens of the Commonwealth about the possibility of elevated arsenic in drinking water wells and to help improve the health of residents, particularly in rural communities.

Arsenic occurs naturally and, in Pennsylvania, is most common in shallow glacial and shale/sandstone type aquifers, particularly those containing pyrite minerals. Arsenic can also result from human activities. Geologic conditions, such as fractures, and chemical factors in groundwater, such as low oxygen, extreme pH, and salinity, can cause arsenic to leach from rocks, become mobile, and contaminate wells distant from the source. Groundwater with elevated arsenic levels – more than 4 micrograms per liter -- can be found in scattered locations throughout Pennsylvania.

Arsenic in drinking water has been linked to several types of cancer, reproductive problems, diabetes, a weakened immune system, and developmental delays in children.

Here is an example from Kanawha County, West Virginia that indicates the amount of Arsenic and other contaminant levels which may leach into soil from improperly buried contaminated pit waste. There is not an easy way to obtain such information from Pennsylvania pit waste lacking the investigation through many file reviews. We just wanted to provide an example of what soil tests may reveal in regards to Arsenic leaching. We are quite aware of the disparity between PA and WV regulations. Again, we are more interested in what a soil sample may reveal regarding contaminated pit waste and nearby private water supplies, especially in view that water supplies within the Northern Tier Region at times have indicated existing

pre-drill sample results have indicated a presence of arsenic. We are concerned about such water supplies and the risk of a further increase of arsenic levels. This report is attached in a separate attachment labeled *Arsenic – example of pit soil screening level 5714_EA*. It is relevant to note that this particular operator, Cabot Oil and Gas also operates in Pennsylvania's Northern Tier Region; attached please find the corresponding completion report. The contaminated soil in this case reveals an arsenic concentration of 16mg/kg. According to this report, the EPA Soil to Groundwater screening level reveals .292 mg/kg as compared to this particular Soil to Groundwater screening calculated to 5.8 mg/kg. Please refer to the attached report for further details regarding this environmental assessment.

- As per 40 C.F.R. 261.24 Table I (As of July 1, 2011): Arsenic's Regulatory Level is 5 mg/L (Maximum Concentration of Contaminants for the Toxicity Characteristic). According to the regulation, which is only revised for "residual" the thresholds for Arsenic, for concentration of contaminants in the leachate from the residual waste are as follows.
    - Does not exceed 50% of Table I - or 2.5 mg/L
    - Does not exceed 50x the primary maximum contaminant level under §109.202; which for arsenic is .010 mg/L or 50x - .5 mg/L
    - As per the previous map, Arsenic concentrations are shown as elevated if greater than or equal to 4.0 micrograms per liter.

Our concern here lies with the fact that there is a greater risk here due to the fact that arsenic is already present in water supplies and that the addition of onsite contaminated residual waste pits may create an unnecessary risk to nearby water supplies. Pits also lack onsite monitoring. Certainly there are options here. Requiring monitoring is one option. Reducing the acceptable contamination level is another. Better yet, we recommend that onsite contaminated residual waste pit

burial be eliminated in favor of centralized disposal where such contaminants are more easily, properly and adequately monitored.

Since the Department has access to information regarding residual waste contaminants that are common to onsite residual waste pit burial, we recommend that the Department review such information along with the enormous amount of water sampling that has been done in areas prone to drilling in order to determine based on present water quality whether there are sufficient safeguards in place to adequately protect water supplies in the event of water resource impacts. This is new information that the Commonwealth has been gathering since the unconventional development began and this is a relevant and necessary review. We recommend centralized landfilling of all contaminated residual waste and request the Department consider this information and eliminate onsite contaminated residual waste pit burial.

78.63. Disposal of residual waste – land application.

78.63(a)(1) The option of land application at the well site is available providing the operator satisfies the requirements. The waste must be generated at that well site. Residual waste generated by hydraulic fracturing of unconventional wells and generated by processing pursuant to §78.58 may not be disposed of by land application. We support this provision for adoption as written.

78.63(a)(2, 3) The changes here reflect the references to Act 13 which are needful. We therefore, recommend their adoption at the minimum as is written.

78.63(a)(5) The proposal also provides for a three day advanced notification prior to pit disposal which may allow for adequate planning for the Department's staff to be onsite and perform an inspection of the work. Therefore, we do recommend both provisions for adoption.

78.63 (20) The proposal incorporates 25 Pa. Chapter 102. We support consistency across the code and recommend this provision for adoption.

78.63(21) (19) To determine compliance with this section, the Department may require the owner or operator to conduct soil surveys, monitoring or chemical analysis.

We support appropriate and reasonable oversight that ensures that the land application is in compliance. We recommend this provision for adoption at a minimum as is written.

78.63(21)(b) We are recommending the same language as is noted in 78.62(b)(1-4) as a point of consistency with disposal of contaminated residual waste including drill cuttings. Additionally, we request that our previous comment above for 78.62 regarding contaminated residual waste and arsenic be also considered in response to this provision.

78.63(21)(c) *The owner or operator may request to dispose of residual waste, including contaminated drill cuttings, in an alternate manner from that required in subsection (a) by submitting a request to the Department for approval. The request shall be made on forms provided by the Department and shall demonstrate that the practice provides equivalent or superior protection to the requirements of this section.*

We want to be clear that in absence of oversight that would normally occur in a landfill situation related to contaminated residual waste disposal including drill cuttings, that we prefer regulated landfill disposal and strongly discourage the Department from approving alternate disposal requests for contaminated residual wastes including drill cuttings. Our concerns lie with protecting our water resources and a variance of oversight in the manner in which landfilled contaminated residual waste is handled as compared to contaminated residual wastes, including drill cuttings as generated by the oil and gas industry. There needs to be a consistency of not only regulations, but also, oversight and on-going monitoring of contaminated residual waste regardless of the disposal locations. More consistency and ease of monitoring is available at centralized locations and we advocate to that end.

78.64. Containment around oil and condensate tanks.

Recent Marcellus Shale history has provided reason to extend this provision to include condensate tanks. Appropriate secondary containment is reasonable and an excellent precautionary measure to adequately protect our water resources. The results of what happens when inadequate containment is relied upon around condensate tanks is detailed in the attached occurrence from one site operated by Cabot in West Virginia. This is relevant as we have seen, corporate personalities are not state specific; they do cross lines especially when regulations prove to be less than a floor and insufficient to effective address environmental impacts or adequately protect water resources. Please refer to attached – *Condensate Spill – lacking secondary containment 2026EA.* In this case, lacking adequate secondary containment, the soil, nearby ditch became contaminated by brine and petroleum. Please refer to the attached environmental assessment for further details. We recommend this provision be adopted as written.

78.64a. Containment systems and practices at unconventional well sites.

Well sites are often located near our homes, schools and even local hospitals. These are industrial sites located in areas that traditionally have not been industrial activity locations. Often they are areas that previously supported agriculture, were forested and may be near private water supplies, and within high quality or exceptional value watersheds. In the Northern Tier Region it is not uncommon for a pond, trickle down stream, wetland, creek, or even a river to be nearby or adjacent to a well pad. There are many chemicals and regulated substances including solid waste that may either be used or generated at the well site. Therefore, in order to adequately protect our water resources and soil, containment structures need to be sufficient to prevent both spills to the ground and from leaving the well site. We recommend at a minimum this provision be adopted as written in its entirety.

78.65 Site restoration

78.65(c) The edge of the play is becoming visible in Wyoming County. There have been dry holes drilled and plugged. There have been well sites built never to see any equipment arrive on-site. Occasionally, since these have been locations of test wells, they are smaller in scope and size such that the operator was not required to have an Expedited Erosion & Sediment Stormwater General Permit and so they did not obtain one. An example of such a site is related to the Chief Oil & Gas Drill Operate Well Permit #131-20127 AMERICAN ASPHALT UNIT 1H OG WELL [Eaton Township]. Since there is no record of an E&S permit, there is also no record on Efacts of any inspections that may have occurred regarding this site. Further it is unclear whether the operator had a PCSM plan according to the DEP Efacts records being no E&S permit had been previously issued. This site was built several years ago. The operator determined to never drill a well there. Recently, this site has been restored. There is no follow up inspection recorded on Efacts. Since the Department was not provided with any plans it remains unclear whether the operator did in fact adhere to procedures that restored the site to the actual *"approximate original conditions including preconstruction contours, and can support the land uses that existed prior to".* This is particularly important where operators are ambitious but lack full understanding of their leasehold. Ideally, we do not want to see any well sites that serve no purpose other than land disturbance to be developed across our landscape. Well sites must not be developed lacking a full purpose to drill and lack any oversight towards development or restoration of the same site. This is an important reason why every well site needs to be required to have an Expedited E&S permit if for no other reason than to ensure that the site is fully restored according to the regulations and that at a minimum there has been a post restoration inspection. The Efacts system currently does not retain information regarding DOW permit renewals. This permit may have been renewed at least once, but it also remains unclear whether or not the well site was restored within the 30 day period previously prescribed in this provision.

78.65(d) There needs to be a mechanism in place whereby the Department reviews the original site with the restoration plan. This is very important in regards to (iii) *All areas of the site not needed to safely operate the well are restored to approximate original conditions, including preconstruction contours, and can support the land uses that existed prior to the oil and gas activities to the extent practicable.* As an example, Chesapeake's permit ESX11-131-0034 FALCONERO LOCATION [Forkston Township] was previously an agricultural field that on the downhill side had supported a diversion ditch that protected water run-off from reaching the neighbor's property. The neighbor's home is located on the downhill side and lacking a properly constructed diversion ditch, the neighbor's in-ground pool and home will become the route for all water run-offs from the field. When the operator was restoring the site post plugging, [this was a dry hole] there was no effort being made to accommodate for the previous diversion ditch. Fortunate for the neighboring landowner, he was home and watching – primarily due to concerns; what was occurring on the adjacent property. When he noticed they were not reconstructing the diversion ditch, he went to speak to the workers. The workers indicated to him, by showing him the plans, that there was no reference to restore the ditch and in fact there was no record of the ditch. The adjacent landowner contacted the operator only to no avail with the common response "not our fault" as often was the prescribed response to problems landowners experienced. Property owners must not be expected to photograph every part of preconstruction contours of their or adjacent properties. In cases of producing wells where full restoration may not occur for decades, no one will recall the original contours and features such as pre-existing and necessary diversion ditches when submitted plans lack these details. Nearby property owners need to be protected from unnecessary and excessive water run-off that may affect their property, especially when it was a pre-existing feature. It is fortunate for the adjacent property owner that he was able to articulate his concerns to the workers and have a successful response whereby the diversion ditch was reconstructed during the site restoration. However, this is one case, and one case in which restoration occurred in a very short interval of time subsequent to the drilling and plugging of a dry hole. That may not be the case in

years to come when plans are erroneous and there are completely different landowners involved that may not remember such features as pre-existing and needful, functioning diversion ditches. The Department needs a mechanism in place to deal with such issues in the future as they no doubt will occur.

Another situation that needs to be considered is when a well is plugged but the operator does not restore the site due to other business arrangements. One such location where this was experienced is Carrizo's ESX10-131-0025 SHIELDS WELL SITE [Monroe Township]. This location subsequently became the site for a pipeline staging area for a gathering line project. Then, subsequent to that development, the site became a staging area for the Mehoopany Wind Farm. We certainly have no issue with the utilization of an area that was constructed to support heavy equipment being used in either construction project. Rather our concern lies with the possibility where this may occur and then the operator and possibly the Department loses track of the site and the requirement to be restored. In review of Site ID 737797 the site restoration inspection is noted along with Violation Inspection ID: 2062442 *Failure to meet requirements of permit, rules and regulations, or order of DEP.* Thus, the Department needs to have a mechanism in place pertaining to similar situations.

78.65(g) The surface landowner needs to be involved when the operator is determining to dispose of contaminated drill cuttings or residual waste on-site. There needs to be a mechanism in place whereby the surface landowner may object to such disposals, at the very least to have their concerns addressed in the process if not to deny such disposal should they desire. Not all leases, not all landowners were aware of such possibilities that their property could essentially become a micro-landfill that is neither fully regulated nor monitored. Therefore, the landowner does need to be involved in this process. We agree that regardless of contamination or not, when disposal is on-site, the landowner does need to be aware of the contents and exact location. There needs to be a requirement that this disclosure is provided in all property transactions to the future surface landowners.

We request the Department consider this information provided and that it be incorporated into this provision. With these additions, we recommend this provision as written.

78.66. Reporting and remediating releases.

This section is the codification of the spill policy. Due to events that have occurred such as those in Bradford County's Rome [Permit 015-20944; Inspection ID 1924655; Violations 598502, 598503] and Wilmot Townships [Permit 015-22087; Inspection ID 2054656; Violations 635518, 635519; Permit 015-21995; Inspection ID 2089544, Violations 646007, 646008, 646009], and throughout our region, we recommend the codification of these provisions as written that provide more stringent requirements regarding the reporting and corresponding remediation at well sites which many times are located near our homes and schools. It is imperative that the spill policy be codified at least as stringent as it is written. With sites so close to private water supplies and even some public water supplies, including those of hospitals, it is relevant to have a record of any spill that may be later attributed to the impact of all water resources. It is of merit to note that in the case of the YARASAVAGE blowout [Wyoming County, Washington Township, 2013] the DEP did sample the nearby hospital's water supply. One operator in our region [Cabot] is complying with Act 2 for their remediation practices. We encourage this option as a preferred remediation release and desire to see it used by all operators.

http://www.pabulletin.com/secure/data/vol43/43-32/1485c.html
LAND RECYCLING AND ENVIRONMENTAL REMEDIATION UNDER ACT 2, 1995 PREAMBLE 3

The Department has taken action on the following plans and reports under the Land Recycling and Environmental Remediation Standards Act (35 P. S. §§ 6026.101—6026.907).

Heitsman 2V/4H Wellsite, Troy Road (T-388), Dimock Township, Susquehanna County, James Pinta, Civil & Environmental Consultants, Inc., has submitted a Final Report on behalf of his client, Andy Mehalko, Cabot Oil & Gas, 5 Penn Center West, Suite 401, Pittsburgh, PA 15276, concerning the remediation of soil impacted by brine from an initial release from the top of a tank located on the well pad. The report documented attainment of the Statewide Health Standard and Background Standard for soils and was approved on July 3, 2013. The report was submitted within 90 days of the release.

78.67. Borrow pits.

With the addition of so many small borrow pits dotting our rural landscape servicing the gas industry, we certainly appreciate standardizing, identification and restoration practices throughout the Commonwealth. We recommend that in such locations, that beneficial use be investigated concerning the application of certified uncontaminated drill cuttings in the use of blending with burrow pit soils in order to aid in restoration of the previous land contours and possible revegetation. The Department needs to encourage beneficial use of uncontaminated drill cuttings. While it may be ideal to utilize such as material in the manufacturing of asphalt pavement and concrete products, lacking endorsement by PennDOT as an approved material will greatly hamper the practical use of uncontaminated drill cuttings as applied to both local and state roads. There may be a practical way through the use of uncontaminated drill cuttings to better restore burrow pits and aid in stabilization and creating minimal erosion. With consideration given to our suggestion, we recommend this provision at minimum as written.

78.68. Oil and gas gathering lines.

Corrosion control requirements as stipulated in Act 13 of 2012 are included in 78.68(h). In addition, it is necessary to add another provision to extend PA ONE CALL to this section. Specifically, we recommend this rulemaking's regulatory language be inclusive regarding the necessity of owners and operators of all gathering lines, inclusive of all Classes, 1-2-3-4, both conventional and unconventional be required to comply with the Underground Utility Line Protection Law. Third party damage to gathering lines may create unnecessary environmental impacts. These situations are worthy to avoid. Excavators do not want to commence project work lacking knowledge of what may be below his worksite/project. They do not want to have issues, injuries, lost time/downtime, insurance claims and the cleanup afterwards. These lines are not currently protected under the UULP. Currently, there are only 45 of 120 PIOGA Producer members; of which about half of Shale Gas Operators currently comply with the UULP. As a matter of public health and safety and environmental protection, we

recommend that mandatory participation in the UULP be required for all Classes 1-2-3-4 of conventional and unconventional gathering lines.

78.68(4)(d) In regards to the backfilling of gathering lines, it is specifically noted that the water infiltration rates should not be decreased. There may be sites where this will be difficult to achieve. Many lines are being placed in native undisturbed soils with infiltration characteristics that have developed over a long period of time. Please consider modifying the wording in those case by case situations to allow the industry to achieve the best possible infiltration rate for the backfilled soils.

We are concerned about the impact of pipeline stream crossings. Conservation agencies work with landowners on a daily basis to install forested buffers along the Northern Tier Region's many streams. Now the pipeline companies are undoing much of what conservation agencies and landowners are accomplishing every time they cross a stream. We recommend a requirement for operators to plant new buffers elsewhere for every acre they destroy. This would greatly increase the integrity of our watersheds. The pipeline companies are required to replace wetlands they destroy, but not riparian corridors, which are equally important. NRCS normally requires a 180' buffer along a stream. So if you tally up every pipeline right-of-way that crosses a stream @100' wide X 180' X 2 (for each side of the stream) - we're looking at a significant amount of acreage of forested buffers that are being lost.

We request this recommendation be added to the rulemaking and with that addition we recommend this provision for adoption as written.

78.68a. Horizontal directional drilling for oil and gas pipelines.

The Department needs the latitude to review stream crossings in glacial till areas that are highly subject to continual erosion due to recent flooding. There are areas where Northern Tier Region watersheds have lost and are continually losing trees

and vegetation. These same streams may be locations for pipeline crossings. Some operators will submit both a trench and HDD plan, while others may only submit one or the other. Ideally, we recommend that operators submit both plans to the Department with their preference noted. For those glacial till stream crossings, we recommend the Department evaluate whether or not the operator's trench plan involves the removal of further trees, shrubs and other vegetation in a stream highly susceptible to erosion issues. Those plants help further ensure the integrity of that stream more than a trenched pipeline crossing. In streams of that nature, where the operator is proposing such a crossing, a proper evaluation needs to be done regarding how likely an HDD operation will be successful and the riparian buffer remains. These areas are not only important locations for immediate downstream neighbors, but also the entire watershed as the Susquehanna River Basin is having an increasing amount of sediment issues. Further, in such crossings the operator can benefit by meeting with the Department's watershed program staff who are able to explain to them the exact nature of not only stream bank erosion but also, stream bed deterioration that does occur and the nature of both can affect the safe operation of their pipeline during serious flooding. Ideally, we want to see pipelines safely installed in such areas at deeper depths below the stream bed in order to avoid pipeline failures. We recommend the adoption of these recommendations as written along with serious consideration to our above noted suggestion.

78.68b.Temporary pipelines for oil and gas operations.

There has been much variation operator to operator and region to region in regards to the operations of temporary pipelines. Not all temporary pipeline operations have been adequate. In this instance brine was discharged from a pipeline, serious enough to warrant further investigation by the Attorney General's Environmental Crimes Section.

AG: Gas pipeline leak fouls well site
By Monica Pryts

WEST SALEM TOWNSHIP — A Cortland, Ohio, company that operates a natural gas pipeline in West Salem Township has been charged by the

http://www.sharonherald.com/local/x546360316/AG-Gas-pipeline-leak-fouls-well-site
December 1, 2009

Pennsylvania Attorney General's office with illegally discharging oil and other waste in the township.

Energy Exploration & Development LLC, formerly known as Energy Exploration Inc., 2202 Niles-Cortland Road NE, was charged Nov. 16 with unlawful conduct for allegedly dumping oil and brine, or salt, water from a section of pipeline along state Route 358, according to a news release issued Tuesday.

Between July 11 and Aug. 13, oil and brine water stained a 30-foot area of soil and vegetation near an abandoned gas well site. The waste was contained to a "relatively small area," AG Deputy Press Secretary Nils Frederiksen said.

Pipeline inspectors from the state Department of Environmental Protection found the polluted area this summer and Mercer County District Attorney Robert G. Kochems referred the case to the Attorney General's Environmental Crimes Section.

The company had no permit from DEP to dump waste in that location. DEP in July 2008 and July 2009 sent the company violation notices that they failed to install measures that would prevent pollution.

"Unfortunately some people don't get the message," Frederiksen said.

DEP told the company to replace a plastic tank at the end of the pipeline with a metal one, but they failed to follow orders, and the pollution and criminal charges could have been prevented.

"A year later we have a problem," he said.

Court records show the company is owned by John and Toni Ross, and Ross told investigators Sept. 17 that oil and brine water were discharged from the pipeline and the plastic tank had split open.

The area has been cleaned up and Frederiksen said he didn't believe there was a large amount of damage, but any damage must be governed.

"Those rules are there to protect people and protect the environment," he said.

The company is charged with violating Pennsylvania's Oil and Gas Act and Solid Waste Management Act for dumping waste without a DEP permit, a third-degree misdemeanor that carries a fine of $1,000 to $2,500 a day.

They're also charged with failing to properly maintain a natural gas pipeline, an ungraded misdemeanor with a fine of up to $5,000.

The company could also be responsible for cleanup costs and everything will be calculated when the case is closed, Frederiksen said.

"We hit the company in the pocketbook," he said.

A message left for the company early Tuesday evening wasn't returned.

http://www.attorneygeneral.gov/press.aspx?id=4874

December 1, 2009

Attorney General Corbett announces criminal charges against gas pipeline company from Ohio

HARRISBURG - An Ohio business that operates a natural gas pipeline in northwestern Pennsylvania has been charged with illegally discharging oil and other waste in Mercer County.

Attorney General Tom Corbett said agents from the Attorney General's Environmental Crimes Section filed criminal charges against Energy Exploration & Development LLC (formerly known as Energy Exploration, Inc.), 2202 Niles-Cortland Road NE, Cortland, Ohio.

Corbett said that between July and August 2009, oil and brine water was allegedly discharged from a section of pipeline located along State Route 358 in West Salem Township, Mercer County, staining a 30 foot area of soil and vegetation near an abandoned gas well site.

"Pennsylvania's environmental laws exist to safeguard our natural resources and protect our citizens," Corbett said. "Businesses have a responsibility and

obligation to take proper steps to ensure that the environment is not harmed by their activity."

The discovery of the polluted area by DEP pipeline inspectors resulted in a referral by Mercer County District Attorney Robert G. Kochems to the Attorney General's Environmental Crimes Section.

According to the criminal complaint, records from the Pennsylvania Department of Environmental Protection (DEP) indicated that no permit had been issued to Energy Exploration & Development allowing the dumping or disposal of waste at that location. Additionally, DEP records indicate that the company had received Notices of Violation in July 2008 and July 2009 for allegedly failing to install measures to prevent pollution from occurring along the pipeline.

Energy Exploration & Development is charged with violating Pennsylvania's Oil and Gas Act and Solid Waste Management Act, including one count of dumping waste without DEP permit, a third-degree misdemeanor punishable by a fine of $1,000 to $2,500 per day, along with one count of failing to properly maintain a natural gas pipeline, an ungraded misdemeanor punishable by a fine of up to $5,000.

Criminal charges were filed before Greenville Magisterial District Judge Brian Arthur, who has scheduled a preliminary hearing for 11:15 a.m. on December 14, 2009.

The case will be prosecuted in Mercer County by Deputy Attorney General Amy J. Carnicella of the Attorney General's Environmental Crimes Section.

Corbett thanked the Mercer County District Attorney's Office and the Pennsylvania Department of Environmental Protection for their cooperation and assistance with this investigation.

(A person charged with a crime is presumed innocent until proven guilty.)

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Creating standards that will adequately protect our water resources especially in areas of stream crossings are an excellent initiative. At a minimum, we recommend these provisions for adoption.

78.69. Water management plans.

This provision codifies Department policy that has been effective since 2008. The SRBC withdrawal model is extended into the Ohio River Basin. The STRONGER, September 2013 Review has recommended that [page 60] the Department *"clearly indicate what is required in a water management plan and make those plans available to the public." (STRONGER 2013 Guidelines Section 9.3.)* C.O.G.E.N.T. supports this recommendation and the provision as it is currently written.

78.70. Road-spreading of brine for dust control and road stabilization.

78.70(a) We recommend the elimination of this exception: *The use of drilling, hydraulic fracture stimulation flowback, plugging fluids or production brines mixed with well servicing or treatment fluids,* ***except detergents,*** *may not be used for dust suppression and road stabilization.* Generally, exceptions confuse and weaken regulations. The public generally wants assurance that brine generated from hydraulic fracturing fluids is not being applied on roads near their homes and private water supplies. Often homes are situated close to the road and the private water supply may be located within 100' of a qualifying road surface. We therefore urge the Department to modify this provision to apply solely to fluids generated from conventional formations. With this consideration, we clearly note that there are no acceptable conditions to permit unconventional flowback, plugging fluids, or production brines to be used in dust suppression and road stabilization and therefore, recommend the adoption of the provision to that end.

78.70a Pre-wetting, anti-icing and de-icing.

We recommend the elimination of this exception: *The use of drilling, hydraulic fracture stimulation flowback, plugging fluids or production brines mixed with well servicing or treatment fluids,* ***except detergents,*** *may not be used for pre-wetting, anti-icing and de-icing activities.* Generally, exceptions confuse and weaken regulations. The public generally wants assurance that brine generated from hydraulic fracturing fluids is not being applied on roads near their homes and private water supplies. Often homes are situated close to the road and the private water supply may be located within 100' of a qualifying road surface. We therefore urge the Department to modify this provision to apply solely to fluids generated from conventional formations. With this consideration, we clearly note that there are no acceptable conditions to permit unconventional flowback, plugging fluids, or production brines to be used in dust suppression and road stabilization and therefore, recommend the adoption of the provision to that end.

78.73. General provisions for well construction and operation.

78.73(c) (Includes Conventional Drillers)

78.73(d)

The STRONGER, September 2013 Review [page 51] encourages the Department *to consider regulations to require operators to evaluate and mitigate potential risk of hydraulic fracturing communication with active, abandoned or orphaned wells and other potential conduits that penetrate target formations or confining formations above. (STRONGER Guidelines Section 9.2.1)*

Provisions 78.73(c) and 78.73(d) provide for the following:

1- Visually monitoring during stimulation activities
2- Immediately notifying the Department of any change to the orphaned or abandoned well
3- Take action to prevent pollution of waters or discharge to the surface
4- An operator who alters an orphaned or abandoned well by hydraulic fracturing is responsible to plug that well.

There are some inherent problems with this provision. First, does it really meet the STRONGER recommendation? The STRONGER recommendation clearly notes mitigate the potential of risk with three types of wells – active, abandoned and orphaned. The procedure of visually monitoring an orphaned or abandoned well does not appear to be a method that may actually make an incident less severe should the unexpected event occur. Once the 'visual' is available, it is too late to prevent a geyser communication. Visual monitoring is inadequate mitigation of potential risk. Secondly, the provision does not include an evaluation of active wells. There needs to be an evaluation to determine whether or not certain well/s may need to be shut-in during the stimulating activity. Third, after the incident of environmental harm, the provision requires that the operator plug the abandoned or orphaned well. The noted STRONGER recommendation reads as a pro-active evaluation. The provision reads as a reaction to an environmental problem.

Therefore, we suggest the following. Once the identification has been completed as provided in 78.52a wells that are evaluated 'at risk' are then mitigated and thus, pro-actively measures are taken to make an incident less severe. For example, an *'at risk'* active well may be shut-in during stimulation activities. An 'at risk' orphaned or abandoned well is plugged in advance of the stimulation activities. An orphaned or abandoned well that is not considered to be 'at risk' but is nearby, may be effectively monitored by using technologies. There are numerous down hole technologies that operators have available that can monitor for changes that would reveal that there is a trend or change in the orphaned or abandoned well. At that point, they would need to notify the Department and then perhaps plugging would be the course of action.

We realize that this is a more pro-active approach than the proposed provision. Since the provision was written, it has come to light that conventional drillers are commencing with horizontal operations at shallower depths than the unconventional drillers. These provisions need to be considered with that aspect.

The operator, by doing the identification after the well spud has been done, has ample opportunity to change their drilling plan and thus, totally avoid any responsibility for plugging an orphaned or abandoned well.

Act 13 of 2012 §3211(f) Well Permits. Drilling – The Act provides for a 24 hour notice of commencement of drilling, and in the case of unconventional wells, the cementing of all casing strings, pressure tests of production casing, stimulation, abandoning, or plugging of an unconventional well. However, as noted in the STRONGER September, 2013 Review [page 52] there is no requirement that the *operators monitor the annulus during fracture stimulation.* Further, the Review recommends *that the State consider requiring operators to monitor for operational and mechanical changes including annular pressures, during hydraulic fracturing to focus on specific factors that could be affected. (STRONGER 2013 Guidelines Section 9.2.1)*

We therefore, strongly suggest that the Department implement this recommendation as a provision in this rulemaking.

78.75a. Area of Alternative methods. The Department has regulatory authority since February, 2011 to designate alternative areas if the Department determines that well drilling requirements beyond those provided under Chapter 78 are necessary to drill, operate or plug a well in a safe and environmentally-protective manner. The STRONGER Review, September 2013 [page 83] notes that *"Finally, the oil and gas regulations at section 78.75a allow DEP to establish areas of alternative methods in a manner similar to the development of a guidance document to establish more stringent requirements than those established by the regulations."*

§ 78.75a. Area of alternative methods.

(a) The Department may designate an area of alternative methods if the Department determines that well drilling requirements beyond those provided in this chapter are necessary to drill, operate or plug a well in a safe and environmentally protective manner.

(b) To establish an area of alternative methods, the Department will publish a notice in the Pennsylvania Bulletin of the proposed area of alternative methods and provide the public with an opportunity to comment on the proposal. After reviewing any comments received on the proposal, the Department will publish a final designation of the area and required alternative methods in the Pennsylvania Bulletin.

(c) Wells drilled within an area of alternative methods established under subsection (b) must meet the requirements specified by the Department unless the operator obtains approval from the Department to drill, operate or plug the well in a different manner that is at least as safe and protective of the environment as the requirements of the area of alternative methods.

Source

The provisions of this § 78.75a adopted February 4, 2011, effective February 5, 2011, 41 Pa.B. 805.

The Department is recognized by the STRONGER Review, September, 2013 as having State/Regional Variations in Criteria, yet the Department has not implemented the use of this provision. This provision was created with our Northern Tier Region in mind, a Region that is prone to gas migration. Until we are at zero gas migration impacts or other unforeseen trends, we recommend that this provision is implemented as it was designed. While beyond the scope of this rulemaking, it is important to note our concerns regarding this particular provision. Recently, it seems that there may not be as many reported/determined water contamination cases. We are unaware whether that result is the effect of better

practices which resulted from the February 2011 improvements in cementing and casing regulations or the fact that there are considerably less wells now being drilled. This provision to our understanding was to provide additional water protections for areas such as our region which has been somewhat prone to gas migration. As we inquired at a 2013 TAB meeting, the gas migration cases such as Sugar Run, Wilmot Township, Bradford County have had a lack of progress/success in solving the problem. We are concerned about this. This incident was first reported in September of 2010, and we've now surpassed three years with no resolution. Many homes were affected to which home treatment was considered a solution. But it remains that the Susquehanna River and Sugar Run continue to display symptoms of methane migration.

At a 2013 TAB meeting, it was stated that that 20 wells have been addressed in that area, and a recent review of Wilmot Township compliance reports reveal a large number of wells with poor cement jobs. However, the environmental impact remains. The operator, Chesapeake Energy has received penalty in part because of this environmental incident. This issue is bringing to mind concerns that need to be addressed. Section 78.75a has not yet been addressed or put into practice since it became effective in 2011. This was a measure in large part that will prevent future gas migrations. These measures need to be made a reality now that they have been effective for practically three years. When there are better methods and regulations to ensure the public's health, safety and integrity of private water supplies in the Northern Tier Region, they need to be utilized.

Additionally, there needs to be a limit defined as to the time period that is actually allowable for an operator to continue drilling more wells in either the township/county/state when an environmental impact such as the methane migration into the Susquehanna River and Sugar Run remains unsolved. It makes no sense to keep drilling in area where there are already an abundance of wells with poor cement jobs, where there has been no resolution to the problem. Therefore, we suggest a five year review, that when there is no resolution by that period of

time, all drilling by that operator in the corresponding township cease and all emphasis be placed completely on resolving the issue. Should the operator not be currently operating in that municipality, then another serious action is warranted to gain their attention and emphasis to resolving an environmental issue created by the operator.

78.121. Production reporting.

It is necessary that production reporting be instituted on a monthly basis. Landowners have a very difficult time reconciling their royalty production details and waiting six or more months to be able to actually compare such figures. Now is the time to re-evaluate this section. When this provision was created with a six month reporting period, landowner/royalty owner considerations were not part of the discussion. Due to numerous problems with royalty payments the time has come to not only consider this, but make a modification. Most gas producing states issue production reports monthly.

EIA 2012 TOP 10 GAS PRODUCING STATES
PRODUCTION REPORTING SCHEDULE

RANK	STATE	REPORTING SCHEDULE	WEBSITE
1	Texas	Monthly	http://www.rrc.state.tx.us/data/production/
2	Louisiana	Monthly	http://dnr.louisiana.gov/index.cfm?md=pagebuilder&tmp=home&pid=209
3	Pennsylvania	Semi-Annually	https://www.paoilandgasreporting.state.pa.us/publicreports/Modules/Welcome/Agreement.aspx
4	Oklahoma	Monthly	http://www.occeweb.com/og/OGforms/form%201004.pdf
5	Wyoming	Monthly	http://wogcc.state.wy.us/choicestats.cfm?Oops=#oops#&RequestTimeOut=6500
6	Colorado	Monthly	http://cogcc.state.co.us/
7	Federal Offshore	Monthly	http://www.eia.gov/oil_gas/natural_gas/data_publications/eia914/eia914.html
8	New Mexico	Monthly	https://wwwapps.emnrd.state.nm.us/ocd/ocdpermitting/Reporting/Production/C115BalancingDetail.aspx
9	Arkansas	Monthly	http://www.aogc.state.ar.us/JDesignerPro/JDPArkansas/default.htm
10	West Virginia	Annually	http://www.dep.wv.gov/oil-and-gas/databaseinfo/Pages/default.aspx

This is a world class play; Pennsylvania is expected to be the #2 gas producing state as was noted at the 2013 year end. http://stateimpact.npr.org/pennsylvania/2013/12/17/pennsylvania-is-fastest-growing-state-for-natural-gas-production/ The Commonwealth needs to seriously apply this fact to not only monthly production reporting but also to supplying royalty owners with the tools they need to protect their interests. As the #2 gas producing state and the corresponding production that entails, the time has come when the reporting needs to be revised to a monthly schedule. While we do understand the production reporting is a self-reporting non-audited system, it is still better than a total lack of information in which royalty owners would otherwise have access. Providing transparency for the Commonwealth's royalty owners, in turn protects the Commonwealth's royalty tax revenues. Therefore, we strongly advocate that the production reporting be changed to monthly.

78.122. Well record and completion reports.

78.122(11-13) We recommend for adoption the proposed required reporting of methane being encountered in other than a target formation, as well as, the country of origin and manufacture of tubular steel products used in the construction of the well, and any borrow pit used for site development if any be included in the drillers log.

78.122(i) The descriptive list needs to be further detailed to include diesel fuel and the corresponding CAS. This provides for another level of transparency that is needful as a result of the recent EPA memorandum regarding the permitting of diesel fuel in hydraulic fracturing operations.

78.122(viii) The total volume of recycled water used needs to be further detailed to include the source of such water when it is processed at a temporary well site or other temporary location and whether that recycled water was generated at that particular well site or from another. This information will provide for a level of transparency regarding the justification of temporary on-site processing or whether sufficient volumes are more readily available for use at a WMGR123 location.

78.122(9) We recommend that any associated fresh water or flowback centralized waste water impoundment and any off-site temporary waste processing facility also be indicated. This will assist the Department in tracking the activity regarding such facilities and whether or not the last identified associated well has been completed such that the corresponding facility will now be moving towards closure and site restoration [that is for the impoundments]. With this modification, we recommend this provision for adoption.

78.123. Logs and additional data.

78.123(d) We recommend that the deadline extension shall be for entire period of the five years, rather than an additional five years. The Department needs to anticipate that wells will be flipped to other operators and with that, perhaps the details may not always transfer to the new owner. The longer the time passes; often records become lost or destroyed. Ideally, we want to see every operator comply with the three year filing. An additional two year extension shall be the exception to the rule, and therefore, we recommend the Department have a conservative view with any extensions that may be approved. With consideration of this modification we recommend this section for adoption as it is written.

Subchapter G. BONDING REQUIREMENTS

78.301. Scope.
78.302. Requirement to file a bond.
78.303. Form, terms and conditions of the bond.
78.306. Collateral bonds – letters of credit.
78.308. Collateral bonds – negotiable bonds.
78.309. Phased deposit of collateral.
78.310. Replacement of existing bond.

While Act 13 of 2012 laid out the bonding framework, we are not comfortable with the overall bonding schedule. The bonding schedule as proposed is woefully optimistic and inadequate. We especially recommend that the Department take a

closer review of the costs entailed with plugging unconventional wells. There is information available from the Cabot plugging and other dry holes that have been encountered in the Northern Tier Region.

http://www.post-gazette.com/powersource/companies-powersource/2014/03/03/Act-13-impact-fees-plunge-in-natural-gas-prices-led-to-more-plugged-wells/stories/201403030176

As excerpted:

In a few instances, Marcellus wells were plugged after mechanical failure, Mr. Jankura said. "One of the common things that could happen during the frack job [is] the connection of the pipe could break," he said.

Or there could be a crack in the cement casing.

That was the case with several Cabot Oil & Gas wells in Dimock Township, Susquehanna County. The DEP began investigating the cause of gas migration in Dimock and linked the contamination to Cabot's wells, although the company continues to disagree with that finding.

Nevertheless, Cabot — calling three such wells "unviable" — decided to plug them in 2011. ***According to public filings, it paid $2.1 million to do so, at an average well cost of $700,000.***

A more typical plugging cost for an unconventional well is around $100,000, according to DEP and industry estimates. *It involves setting cement plugs where the well comes in contact with oil, gas or water, and spacing the plugs with bentonite gel, to reduce costs.*

While Marcellus operators often say that shale wells will produce for decades, they may not be economic for that long. ***When the cost of maintaining the well outstrips the value of its bounty, operators will either plug it or sell it to a smaller company, according to Austin Mitchell, a researcher at Carnegie Mellon University who studies well plugging economics.***

For some Marcellus wells, that time has already come.

Range Resources Corp., the Texas-based operator that was first to the scene of the Marcellus and drilled its first unconventional well here in 2003, has plugged 62 wells so far.

"It's a combination of operational and technical [reasons]," said Matt Pitzarella, a spokesman for the company. "Almost all of the vertical [plugged] wells, they were test wells."

In 2011, Range drilled a horizontal well in Donegal Township, in Washington County, which produced a decent amount of gas and natural gas liquids. The company plugged it just two years later because Range developed newer, more productive wells nearby.

"We're drilling them better, completing them better," Mr. Pitzarella said.

The cost to maintain a well, including inspecting it, sometimes means it's not worth keeping an older, less productive well active. If the company already has recovered its development cost and broken even, it might plug an older well, he said.

"It's almost always because you have a more efficient multi-well pad nearby," he said.

There are also other factors.

"We might have been trying a new area. We may have been testing a new technique and it wasn't optimal," Mr. Pitzarella said. "Or we may hit a fault."

We are concerned regarding a known trend that smaller operators may overtime obtain ownership of marginal unconventional wells and not have the funds to plug and will abandon wells. We are concerned about an unforeseen incident, such as so large in scope that it may conceivably result in a financial hardship that an operator abandons wells. Lacking adequate bonding, we are very concerned that we may add to our heritage of legacy wells, but with much larger problems being the footprint of unconventional wells are so much larger. When we hear the industry say we are going to be here for a very long time and we will not be abandoning wells, it is easy enough to view the state of Wyoming whom now is dealing with a recent play [1995-2004] boom that has left them already with 1,200 abandoned wells that need plugging. We need not be so self-assured by an industry that has a heritage of not always necessarily leaving an area better than when they arrived. This only benefits industry of not funneling appropriate funds for bonding and potentially leaving further extended generations of drillers to pay increasing plugging fees for other's misdeeds, along with the Department's further inability to address an additional backlog of wells that may threaten public health and safety and the environment, especially our water resources.

With conventional operators, such as Penneco now drilling conventional lateral wells, it is imperative that the Department further review the conventional bonding

schedule to ensure that it is adequate to address those types of abandon wells in the future.

The Department's Fact Sheet on Oil and Gas Drilling and Production in Pennsylvania states as noted below.

OIL AND GAS WELL BONDS

Wells drilled in Pennsylvania after April 17, 1985, must be bonded. The bond is a financial incentive to ensure that the operator will adequately perform the drilling operations, address any water supply problems the drilling activity may cause, reclaim the well site, and properly plug the well upon abandonment. The bond amount for a single well is $2,500; a blanket bond to cover any number of wells is $25,000. For unconventional wells, bond is determined by the number of wells the operator has; and, ranges from $10,000 per well up to a blanket bond covering all wells of $600,000.

Based on the information provided along with comparison to this bonding summary, it is clear that Act 13 of 2012 did not properly consider all relevant information with the calculation of the new bonding schedule. Some of this information, such as conventional horizontal wells and the state of Wyoming's recent boom and bust 1,200 abandoned wells were not even news items in 2012. In further consideration, that the bonding is a *"financial incentive to ensure that the operator will adequately perform the drilling operations, address any water supply problems the drilling activity may cause, reclaim the well site, and properly plug the well upon abandonment,"* we do lack confidence that the present bonding schedule is sufficient to make those goals a reality. We strongly recommend that the Department consider our concerns regarding the bonding issue and revise these sections towards more stringent requirements.

OTHER RELATED SURFACE ISSUES NOT COVERED IN THIS RULEMAKING:

1. **Issues relative to locations where there are no local ordinances to protect nearby residents in order that they may be comfortable within their homes.**

Since it is not uncommon to have sites within hundreds of feet of homes it is important to provide for a common sense approach to such situations that will create appropriate guidelines when there is no local planning or zoning in place.

Our Northern Tier Region, primarily as a cultural aspect of our rural population does not have an abundance of zoning and planning in the communities where much of this development is occurring. Are the concerns and impacts of those whom live so very close any less important than their counterparts in zoned communities? We would say no. What we see is that generally, there is enough wide open space here in our Region that a good operator is more often than not able to site the edge of a well pad easily beyond 750 feet from the nearest occupied dwelling. With the advent of horizontal drilling, there is much flexibility whereby the operator may make better siting choices. Landowners generally have an opportunity to discuss the well site location with the operator when it is located within their property boundary and may advocate moving the well site location within parameters that are acceptable to the operator. Those that are often not included in this conversation are the nearby neighbors whom on occasion have the well site location sited closer to their home than the location landowner and at times may suffer tremendous and unnecessary impacts. Often such poor sitings may have been avoided. Operator's land men advised folks during the leasing period that these were temporary events. We've learned they are anything but temporary as they return again and again. These events can be described as nothing short of intermittent at best. We've also learned they are not temporary events as they do not occur for a two week interval at the maximum. Rather, they can very well last for several months as some operators now spud holes for anywhere between 3 and 9 or even 12 wells and move the rig on-site to just keep drilling and later fracturing. Consider for example, the Plushanski Well Pad located in Lemon Township, Wyoming County. There are 13 wells permitted for this location. Lemon Township lacks local planning, zoning and ordinances.

PLUSHANSKI WELL PAD				DRILLING ACTIVITY ON WELL PAD FROM 5/24/2013 SPUD THROUGH 2/26/2014	
LEMON TWP WYOCO				9 MOS FOR SIX WELLS	
RIG MOVED OUT AROUND 2/26/2014					
AUTHORIZATION	PERMIT	WELL NAME	ISSUED	SPUD	INSPECTIONS
971623	131-20293	PLUSHANSKI WEST 3H	5/20/2013	5/24/2013	5/31/2013 12/27/2013 1/3/2014 1/21/2014 2/6/2014 2/19/2014
971626	131-20295	PLUSHANSKI WEST 5H	5/20/2013	5/24/2013	5/31/2013 6/26/2013 6/27/2013 10/1/2013
971625	131-20294	PLUSHANSKI EAST 4H	5/20/2013	5/24/2013	5/31/2013 1/30/2014
994202	131-20294	PLUSHANSKI EAST 4H	10/11/2013		
994187	131-20292	PLUSHANSKI WEST 2H	10/2/2013		5/31/2013 12/4/2013
968015	131-20286	PLUSANSKI EAST 1H	4/30/2013		5/31/2013 12/10/2013 12/19/2013
981286	131-20333	PLUSHANSKI EAST 9H	7/24/2013		
981289	131-20334	PLUSHANSKI WEST 10H	7/24/2013		11/20/2013
971633	131-20297	PLUSHANSKI WEST 7H	5/20/2013	5/24/2013	5/31/2013 6/26/2013 10/10/2013
971634	131-20298	PLUSHANSKI EAST 8H	5/20/2013	5/24/2013	5/31/2013 8/5/2013 10/23/2013 10/25/2013
971630	131-20296	PLUSHANSKI EAST 6H	5/20/2013	5/24/2013	5/31/2013 6/24/2013 7/15/2013 11/8/2013
981290	131-20335	PLUSHANSKI WEST 11H	7/24/2013		
971621	131-20292	PLUSHANSKI WEST 2H	5/20/2013		11/25/2013 12/4/2013

This is an example of when drilling multiple wells in succession may work well. There were no serious violations or spills, which only makes sense really. The more stationary an industrial location is, the better opportunity for effective controls. Also, it works well for the Department's inspectors having continual opportunity to inspect the same operation for compliance. This type of operation may work well when the neighbors are sufficiently in the distance and do not experienced intolerable, tremendous noise levels. The nearest neighbor at this location is roughly 650' while most are beyond 750' and even a 1,000' or more. The Department needs to consider cases where extended drilling and fracturing events occur such as this and the neighbors are within 750' of the well pad edge that may need noise abatement measures such as temporary, portable sound barriers or sound curtains. The neighbors need to be able to be comfortable within their homes when site activity continues beyond 30 continual day's duration. Due to local topography and other factors, it may not be necessary at every site for the operator to provide noise mitigation measures during drilling and fracturing. However, for those few neighbors that do need such protective measures, there needs to be a reasonable mechanism to provide them. This is the pathway to reaching the delicate balance where all may thrive.

We also want to be clear on this aspect. We certainly are not opposed to multi-well pads. In fact, we are encouraged to see a well site with a 13 well plan. More wells equate to less land disturbance and all issues that may relate to that. Where our concerns lie are noise, light, increasing air emissions and water

quality issues in an area just a few years ago was primarily family living environs and not industrial resource extraction locations. Therefore, it is necessary to consider and implement mitigations in order for operations such as these to be Marcellus Shale success stories.

While successive drilling and fracturing saves operators considerable money through a one rig transport event, it is an undue hardship on those that live too close and have to endure tremendous and intolerable noise with industrial activity 24/7 for months and months on end. Certainly with the cost savings they reap in such an event, there is a reasonable opportunity to apply a portion of savings to the installation of temporary, portable sound barriers or sound curtains.

Small, rural municipalities fail to act and create local planning and zoning for a number of reasons. One, they have a small population and perhaps even a smaller number of their residents are affected by these situations. It is a matter of economics that they choose not to spend either tax dollars or impact fee revenue on creating such ordinances that may only benefit a small minority of residents. Secondly, they lack sufficient support staff to administer the necessary ordinances as they have been advised to not use impact fee monies to pay salaries and benefits. Third, they may lack enough interested residents to complete the complement of a municipal planning commission and zoning hearing board. In rural areas, it is not uncommon to have a lack of positions filled for basic municipal positions such township auditor, constable or committee person for example. Fourth, it is not uncommon for municipalities to be concerned about reprisals should they implement ordinances that the gas industry may challenge and further impact their township financial considerations with expenses related to litigation which they may ill afford. While it may be said that small municipalities may join together and create multi-municipal plans, due to rural culture again that is not always feasible as

their neighboring municipality's residents may not be similarly impacted where they may be interested in forming a multi-muni plan alliance.

It is because of these situations, and the fact that all residents regardless whether they live in a zoned municipality or not, need to be availed of basic and reasonable mitigation measures that provide for them to be comfortable within their homes during well site drilling and fracturing activities while simultaneously assuring them of their safety. A family's worth and the value of their home must not be dictated by whether or not they live in a responsive zoned community. All families contribute to the social framework of our Commonwealth and need to be similarly regarded as having such value. It is also because of topography and personal preferences that we suggest that nearby residents have an option to sign a waiver and decline such mitigation measures. There is no need to require mitigation measures when clearly they are not needed. Not all residents may be equally affected by noise or lighting due to seasonal variations, tree buffers, elevation as compared to the site location, having young children, school age children, chronically ill or infirmed family members in the home. Unreasonable, intolerable noise levels for example in such situations may be extremely hard to bear. Care of an infant with such noise, children needing to do homework and be well rested for the next day of school, adults needing to have a good night sleep for the next day of work or those suffering from chronic and infirmed health issues need to have the benefit of mitigation measures. Others may not have such an experience or need, and they may very well, and rightly so, choose to sign a waiver for mitigation measures. Had the gas industry made good choices in sitings in regards to proximity to homes, it would not be necessary to deal with this situation. The sad fact is they have not in some cases chosen to site well pads and other facilities in a responsible manner or voluntarily utilize available mitigation technologies. When they fail to operate in such a manner, they have effectively chosen to be regulated to do so. That is where local planning and zoning are appropriate. The Commonwealth needs to recognize the short falls to local planning and zoning

and step in where that local planning is nonexistent in order to aid those residents living nearby well sites and facilities. When there is no available entity available to assist those with impacts from neighboring properties where they had or have no avenue available to them it is only reasonable that the Commonwealth provide reasonable and adequate measures to assist.

a. **Noise** - When it comes to noise, we are not referencing noise that windows are closed and the noise is absent or at tolerable levels. We are specifically referencing industrial noise from gas operations that are so tremendously and intolerably loud that sleeping is difficult or interrupted, common in-home activities such as TV watching is difficult since the site volumes overwhelm the TV and similar in-home activities to which the resident has no available means to adapt. Again, we are not referring to noise levels that may be considered annoying, but rather those noise levels which prevent normal and reasonable living conditions within one's home. In regards to well site drilling, fracturing and other intermittent facility operations, we recommend the noise level does not exceed a noise standard of 60dbA at the nearest property line or the applicable standard imposed by Federal law, whichever is less. - At a minimum, we recommend that the C.F.R. Title 18, Chapter I, Subchapter E, Subpart F, 157.206 Standard Conditions (b)(5)(iii) ***Any horizontal directional drilling or drilling of wells which will occur between 10 p.m. and 7 a.m. local time must be conducted with the goal of keeping the perceived noise from the drilling at any pre-existing noise-sensitive area (such as schools, hospitals, or residences) at or below a night level (L_n) of 55 dBA*** be adopted for all well pads and other facilities located in non-zoned municipalities with occupied dwellings within 750' of the well pad edge, thus requiring proper noise mitigation unless waived by all those occupying dwellings within that distance. This is an extremely liberal noise threshold

given that fact that ambient noise samplings in our rural areas have indicated results of 35 decibel levels.

i. This may require the operator to erect a temporary, portable sound barrier or sound curtain. There is a Pennsylvania based company that offers such services. Oeler Industries, Inc. offers portable sound barrier products that may be used in both drilling and fracturing sites. When such products are indeed available, the neighbors need to be considered. The operator needs to do such mitigations. The fact of the matter is the operator chose the location. When they choose to operate within 750' [from the well pad edge] of occupied dwellings, they have determined in the same mode to utilize noise abatement technologies. The Department needs to protect the environment of the neighbors who live within 750' [well pad edge] of an active site. More information on Oeler Industries may be found here:

- http://www.marcellusnoise.com/
- http://www.marcellusnoise.com/fracking.html
- http://www.marcellusnoise.com/drilling.html

b. **Lighting –** The lighting needs to be respectful of the neighbors. The lighting needs to be directed on the facility not a thousand feet to the neighbor's homes. Some operators are employing the use of *Lunar Lighting* while many are not. *Lunar Lighting* is an emerging technology in the oil and gas fields, in fact, as you can see here, http://www.texasoilgasmagazine.com/conferences-expos *The Texas Oil & Gas "Emerging Technologies" Conference & Expo will bring together industry experts who will discuss the emerging technologies, processes, and applications utilized in the Oilfield in Texas. The Conference Experts will speak about the developments that are evolving in the Mid-Stream, Up-Stream, & Down-Stream areas of the Oil & Gas Industry. Some of the topics covered will be Lunar Lighting, CNG Fleet & Commercial Vehicles, LNG: A Sustainable Energy Resource, HSE Training, and many more to come. Learn about the*

Challenges and How Effective Utilization of these Technologies can result in being more profitable and effective in the Industry. Visit the Expo to talk to Experts that are bringing in their latest technological advances to showcase for attendees. Network and build lasting relationships that will expand your marketplace and bring businesses together! You will want to be here at the Epic Conference and Expo of the Year!

Event Name: 2014 Texas Oil and Gas "Emerging Technologies" Conference & Expo
Date: October 14-15, 2014
Venue: Reliant Park, Houston, Texas
Organizing Company: 4 X-Stream Media, Inc
Contact Person: Leah Terry, Conference Director
Contact Number: 210.853.0213 210.284.1231
Email: LeahTerry@TexasOilGasMagazine.com

i. Other resources on *Lunar Lighting*:

1. http://www.lunarlighting.com/
2. Youtube: http://www.youtube.com/watch?v=DmxWapYVuKs
3. http://www.azomining.com/equipment-details.aspx?EquipID=135
4. http://www.forconstructionpros.com/product/10764486/lunar-lighting-pty-ltd-lunar-lighting-tower

ii. When operators choose to establish sites in close proximity to homes, within 750' they are simultaneously choosing to mitigate their impacts in every possible way to ensure that the neighbors are comfortable within their homes and that our rural and agricultural integrity remain in place. The fact is that operators have determined most often to comply with local ordinances at a minimum, or have not taken any steps towards mitigation regarding either lighting or noise issues in communities where there are no local ordinances. If the Commonwealth of Pennsylvania is going to be a leader in a world class shale gas play, then the operators need to be functioning as world class, appreciating and respecting the communities where they operate regardless of local ordinances. Since we know from experience that we are not able to be effective with every operator 'doing it right' every time, the Department needs to create a basic floor of

regulations that provide that those that now dwell within 750' of well pads and facilities [edge of site locations] have issues such as lighting and noise regulated with a basic floor of regulations. The zoned communities may choose to build upon these mitigation regulations, but nevertheless, those that dwell in non-zoned communities are still deserving of these basic and reasonable mitigations whether or not their municipality or county fail to act upon doing so.

c. **Setbacks** – We recommend that all setback distances related to occupied dwellings be measured from either the edge of the well site or the limit of disturbance. Noise is not specifically contained at the wellbore; rather noise is generated at every location on the well site from the access road to the actual well site. It is more reasonable that all setbacks related to the noise issue are measured from the edge of the activity. We prefer a 750' setback from the edge of the well site to all occupied dwellings. This distance provides the operator with an opportunity to avoid noise abatement measures in many instances. This measure provides for further dispersion of VOCs and HAPs generated on the well site which is of benefit to the nearby residents. This distance also provides for a better safety buffer. With consideration to incidents such as that have occurred with ATGAS, POWERS, YARASAVAGE, MAZZARA and now LANCO, the Department is gathering further information concerning the effects beyond the well site towards what distances are affected in the case of an unexpected incident. While in contrast to the number of wells drilled these may not be considered frequent occurrences, they are nevertheless lessons learned in how close is too close to site dangerous industrial operations that may have blowouts, fires, explosions and large spills affecting nearby resident's public health and safety. The Department needs to continue to accumulate this data

and create measures that will provide that safe distances are determined and residents will be safe.

d. **Contact** – On occasion, those nearby well sites are affected by operations during drilling and fracturing events. The operator needs to be required to provide residents within 750' of the well pad edge a key contact person when necessary. Such impacts may be the accumulation of diesel fumes within their home that may easily be corrected by the proper queuing of sand trucks for example. The operator may not be aware that the residents are having this problem lacking that phone call. We do not want to see the neighbors approaching a busy well site in order to gain assistance; they need a point of contact. Not all operators are responding to residents' inquiries now that all their agreements have been signed. Well sites also change ownership and the residents may not be aware of the new contact that may be able to assist them.

Mitigations for noise and lighting can be very helpful to creating that delicate balance where all may thrive. Not every well site is going to need these mitigations and not every neighbor will desire them. They need to be offered to all those living within 750' of the well pad edge whom can benefit from them should they feel they need them to be comfortable within their homes, or they can sign a waiver. Some residents may desire only noise mitigation and not lighting mitigations, some may desire both. Therefore, the waiver needs to be a two-step process, as we see no need to for mitigation measures not desired by the neighbors within 750' of the well pad edge.

It is imperative that the Commonwealth approach this issue in such a manner that we experience a Marcellus Shale success story. Ideally, we are seeking a balance where all may thrive. When an operator effectively chooses not to do reasonable and adequate mitigations that provide their neighbors to be comfortable within their homes during site activity; the result is not a Marcellus Shale success story.

When operators advertise or state at meetings they will comply with all local ordinances, knowing full well there are none, that is not a Marcellus Shale success story. There is a delicate balance that may be reached where all may thrive. There are opportunities for well sites and facilities to be located near homes and essentially within the shadows of each other and the residents are not inconvenienced and uncomfortable. This is possible. Unfortunately, when operators refuse to return calls from their neighbors to discuss legitimate site specific situations, residents have no avenues to advocate for reasonable mitigation measures when there are no local ordinances in place. Lacking regulations, there is no way to ensure that every time a family's request will be considered or acted upon. Thus, it is imperative that the Department fully consider the welfare of the well site's and facility's neighbors and institute common sense guidelines in regulatory language to ensure the Commonwealth does have a Marcellus Shale success story and we reach that delicate balance where all may thrive, public health and safety, environment, community, industry, all balanced with respect, consideration and the needs of each other. Therefore, we recommend that the Department consider this information we have provided along with its reasonable nature and establish provisions in this rulemaking we are so strongly advocating.

2. **Act 13 Provisions**
    a. **Well Permits –** The requirements in Act 13 §3211. Well Permits. We recommend these be added to the rulemaking due to the uncertain present status of Act 13 of 2012 and the Commonwealth Court. Specifically, these provisions, including the documentation of water supplies within 1,000 feet of a conventional bore and 3,000 feet of an unconventional bore become part of the regulatory language herein. We also advocate for amending the conventional bore given recent consideration to conventional drillers commencing with the use of horizontal drilling within shallower formations. It is necessary for the provision to also include the requirement for mailing of the plats to

landowners as specified in the Act, the various 24 hour notices, and all other requirements as specified in Act 13 §3211.

b. **Well location restrictions –** The requirements of Act 13 §3215. Well location restrictions. We recommend these be added in their entirety to the rulemaking due to the uncertain present status of Act 13 of 2012 and the Commonwealth Court. Of special concern to us are those provisions relating to 100/300' distance to blue-lined stream, spring or body of water; including the edge of the disturbed area 100' setback to any blue-lined stream, spring or body of water; within 300' of a wetland and maintaining the 100' setback from wetlands. We also recommend the provisions related to the protective waiver be included in the regulatory language of this rulemaking. Additionally, the 750' additional protective measures need to be included. And all provisions related to floodplain activity need to be included in the regulatory language as well.

c. **Presumption –** The requirements of Act 13 §3218. Protection of Water Supplies. We recommend these be added in their entirety to the rulemaking due to the uncertain present status of Act 13 of 2012 and the Commonwealth Court. We are especially concerned about our not having these hard fought protections as a result of court decisions to which our Region was not even considered a party. These protections are very important to our region and they all, especially the presumption, need to be adequately and sufficiently detailed within the regulatory language of the rulemaking.

d. **Air emissions –** The requirements of Act 13 §3227. Air contaminant emissions. We recommend these be added in their entirety to the rulemaking due to the uncertain present status of Act 13 of 2012 and the Commonwealth Court. It has taken several years to move forward with the unconventional air emissions inventory. We need this regulatory language in effect regardless of the status of Act 13 of 2012.

e. **Act 13 of 2012, Subchapter E** - We recommend these provisions be added in their entirety to the rulemaking due to the uncertain present status of Act 13 of 2012 and the Commonwealth Court. These are very needful tools for the DEP to utilize with respect to environmental protection. We therefore recommend that these provisions be included in the rulemaking's regulatory language.

f. **Act 13 of 2012 Setbacks** - *The 2012 Oil and Gas Act extended the setback distance for unconventional wells from 200 feet to 500 feet from existing buildings or water wells, unless consent is provided by the owner of the building or water well. 58 Pa.C.S. § 3215(a).*

The Act established a 1,000-foot setback for an unconventional well from a water supply extraction point used by a water purveyor, unless written consent is provided by the water purveyor. 58 Pa.C.S. § 3215(a).

We recommend these provisions be added in their entirety to the rulemaking due to the uncertain present status of Act 13 of 2012 and the Commonwealth Court. These are very needful, protective public health and safety measures for the DEP to utilize with respect to environmental protection. As previously discussed in our comment, we'd even prefer to see the 500' measure modified to 750' as measured from either the pad edge or limit of disturbance; at least in rural locations where there are no existing local ordinances. We therefore request consideration for our preference, but nevertheless recommend that these provisions at a minimum as written be included in the rulemaking's regulatory language.

g. **Well Plugging Funds.** - §3271 Well plugging funds. Recent events brought to light in both Pennsylvania and Wyoming necessitate in our comment regarding the stipulated surcharge. Pennsylvania has a long legacy inventory of wells needing attention. This is the direct result of the historical conventional drilling operations in Pennsylvania for well over one hundred years. The costs associated with plugging every abandoned and orphaned well can not even be adequately

calculated. We are now in the Grand Era of Marcellus Shale. Exploitation in earnest will continue within our Commonwealth for decades to come. There have been events where these old wells have created problems with the new unconventional drilling. They have the potential to be serious environmental problems and at times, already are. We therefore, recognize that while this is a huge problem, we are not sufficiently attacking it with the current fee surcharge structure. We recommend therefore, that the $50 abandon well surcharge specified in Act 13 of 2012 be revised to $100. We recommend that the $100 surcharge for wells to be drilled for oil production be revised to $200. We recommend that the $200 surcharge for wells to be drilled for gas production be revised to $400. While these amounts are increased 100%, in reference to the cost of a drilling permit and these surcharges as compared to the entire expense of drilling a well, these are really modest expenses. However, they will provide a much greater basis for the Department to increase emphasis on this environmental problem. Additionally, it was recently noted that the state of Wyoming is having serious problems with abandoned wells, and they are not from a hundred years gone by. They are in fact, from a more recent history, from 1995-2004, Wyoming's recent boom years. The boom years have left the state with 1,200 abandoned wells that require plugging. Companies are not taking responsibility. Therefore, we are concerned about our old inventory of wells being augmented with a new batch of abandoned wells as we are experiencing a drilling renaissance. The Department needs to take advantage of this renaissance opportunity through a modestly increased surcharge to work towards cleaning up the legacy of the past generations of Pennsylvania drillers.

3. **Setback Provisions for non-zoned locations may be waived by landowner** – Many of our rural municipalities' lack planning and zoning that

would adequately provide for reasonable setbacks related to sites located near homes. It is becoming plainer with each dangerous incident that has occurred whether it be the ATGAS [Bradford Co.], YARASAVAGE, MAZZARRA [Wyoming Co.] and most recently, LANCO [Greene Co.] indicate that when there is a problem, there is an area much too close. In the case of ATGAS and YARASAVAGE a blowout occurred where flowback water was flowing too near homes. In the case of MAZZARRA, treated flowback water flowed until it was contained in the basement of a nearby home. And, LANCO, thank goodness there were no homes within 1,000 feet, but if there had been within 500', we are concerned how the intense heat would've affected a home within 500' and the safety, health and welfare of the residents. There are many benefits to horizontal drilling, and one which has not been adequately realized is that these sites do not have to be so very close to adjacent homes. There can be adequate setbacks adopted. We recognize the right of the subsurface owner to exercise their gas rights, so, we advocate that in situations where future well pads and impoundments are proposed that a minimum setback to occupied dwellings be designated that may be waived by the homeowner. The homeowner may choose to live closer should they determine to make that informed choice. Reasonable and appropriate setbacks provide a measure of protection for public health, safety and the environment, that presently some folks have been neither adequately nor currently provided. We recommend 1,000' setback for a well pad and 500' for an impoundment facility. We would also be inclined to agree with a 750' setback, however, that distance would involve appropriate mitigations that may be needful in some cases to provide for residents to be comfortable within their homes. We recommend 1,200' setback from the nearest occupied dwelling or 200' from the nearest lot line, whichever is greater, for compressor stations, gas processing facilities, dehydration facilities, and natural gas distributed energy facilities. These measures are based on experience with incidents as mentioned and by Northern Tier folk's experiences where sites have been permitted to close to their homes for

basic living comfort. We need to be serious with reaching that delicate balance where all may thrive. Folks need and deserve to be comfortable within their homes and safe. When the local governing body fails to act regarding these basic protections, the Commonwealth needs to have a simplistic approach that will provide for these basic and most needful protections.

4. **Well pad spacing - *New Provision: Well Pad Spacing***

Well pad spacing – not addressed in this rulemaking is a minimum distance for well pad spacing. Horizontal drilling provides the advantage of more wells per pad, and thus better spacing. Our communities are more impacted with more pads than otherwise is needful. Our region is not an arid, flat, unpopulated area. Well pad spacing patterns of the past are not reasonable operations here. Operators must utilize appropriate well spacing development plans, ideally with a minimum 3,000' spacing between pads. Operators advised landowners of 3,000' spacing when the development commenced. Minimum 3,000' well pad spacing is workable. When the industry first arrived here in the Northern Tier Region, some operators advised that they would have 3,000' well pad spacing, [between pads on that particular row]. While that spacing is workable within our communities, many pads are spaced much closer, and some that are much too close. Effective fracture propagation provides for a certain reasonable distance and thus spacing. Not all operators are adhering to such a practice, and not all the time. Below are examples of a few Northern Tier sites that are much to close, these are perhaps the worst of the well pad inventory. There are many more pads that are spaced with less than 2,000' spacing and more with less than 3,000' spacing. Ideally, the technology is available, that our communities can be pretty much guaranteed with a minimum 3,000' well pad spacing and the distance between well rows, can be an effective 3 miles. The lengths of horizontal bores have created this placement equation. However, not all operators are proceeding with responsible pad placement strategies. We therefore, recommend that the rulemaking be revised to

incorporate such a strategy floor that will protect the integrity of our rural, farmland and forested communities and with that, future land use options for landowners. Please note that the development in Sullivan County is proceeding at a much slower pace and thus, we are not yet aware of such instances there. Creating a provision now, may result in preventing future poor pad placements in Sullivan County and all our counties from such that the rest of our region has experienced.

- **Susquehanna County, Springville Township,** MOGRIDGE PAD, permits 115-20654, 115-20655, and 115-20653 all are unconventional horizontal wells and CHUDLEIGH PAD, permit 115-20189 an unconventional horizontal well; from well bore to well bore the distance is less than 850'. Notably, the well pad edge to well pad edge measure is considerably less.
- **Wyoming County, Meshoppen Township**, BREWER PAD, permits 131-20376, 131-20341, and 131-20340 are all unconventional horizontal wells and REIMILLER PAD, permits 131-20214, 131-20215, 131-20255 and 131-20256 are all unconventional horizontal wells. The distance from well bore to well bore is less than 500', and for all intents and purposes, these well pads are essentially back to back.
- **Bradford County, Springfield Township,** HARKNESS 3H PAD, permit 015-20278, is an unconventional horizontal well and HARKNESS 2H PAD, permit 015-20277 is an unconventional horizontal well. The distance from well bore to well bore is approximately 674'. Notably, the well pad edge to well pad edge measure is considerably less, approximately 367'.
- **Tioga County, Sullivan Township**, EMSPON R 235 1H PAD, permit 117-20278 and HEPLER D 235, permits 117-21534, 117-21533. All permits are unconventional horizontal bores and the distance

between the individual pad well bores are approximately 1,134'. Notably, the distance, well pad edge to well pad to edge is much closer.

- Another item we have noticed is in locations where the Susquehanna River bed has not been leased. In such locations, the laterals are much shorter and the well sites are also closer. An examination of well sites and wells of Citrus Energy in Washington Township, Wyoming County clearly indicates what may happen in such situations. We end up with more disturbed land, more earth disturbance issues, more well sites and more gathering lines. One well site has even been built practically on the river bank, save the location of the adjacent railroad track. This is not good planning if protecting the river is the ideal. The well sites in this area, especially, 131-20158, 131-20143, 131-20024, 131-20315, 131-20313, 131-20316, 131-20025, 131-20255, 131-20215, 131-20214, 131-20222, 131-20256, 131-20032 need to be reviewed with the laterals and determine how likely it is that there may have been more well sites and wells than may be necessary due to the location of the river and inadequate or absent guidelines on the manner of development in relationship to non-leased riverbed locations. The Department needs to review this area along with the development of other near river locations and determine the manner in which a regulation or other mechanism may create better outcomes. We need to do this better. There needs to be a mechanism in place that creates that avenue.

5. **Waste Hauling Certification** – We draw your attention to the STRONGER Review, September 2013, page 30.

   RECOMMENDATION II.10.A. *The review team recommends that DEP consider whether a program for certification of commercial waste haulers is appropriate. (STRONGER 2013 Guidelines Section 4.2.5.)*

RECOMMENDATION II.10.b. *The review team recommends that DEP develop a training program to ensure E&P waste hauler compliance with regulations under the Solid Waste Management Act. (STRONGER 2013 Guidelines Section 4.2.5.)*

The purpose of the STRONGER Review is to offer recommendations for program improvement. When a STRONGER Review provides such recommendations, it is necessary for the Department to advance with those improvements that will add additional measures to protect public health and safety and the environment. Therefore, we recommend that the Department follow through with these recommendations and create any regulatory language and corresponding guidance documents that may be necessary.

6. Conventional Horizontal Drilling

Penneco and other conventional drillers are exploring the use of horizontal drilling as a new method within the conventional oil and gas fields. Since this is a relatively new variation of conventional drilling, we caution the Department in regards to the manner in which the proposed rulemaking may be revised in relation to conventional drillers. We urge the Department to err on the side of more stringent not less in order to be adequately prepared for the manner in which horizontal drilling may affect environmental protection within shallower depths closer to our water resources.

OTHER ISSUES not included in this rulemaking C.O.G.E.N.T. recommends be addressed in the future:

1. Recommendation – Staffing - Sept 2013 STRONGER page 19

While not necessarily part of a rulemaking, we do want to encourage the Department to continue to evaluate staffing needs regularly. We are aware that subject to the pending fee increase, the Department does intend to add a complement of new staff positions.

Recommendation I.6.a.
The review team recommends that DEP continue to evaluate whether it has sufficient staff and funding resources to manage current and projected oil and gas well development activities, including resources to address emergency issues if an operator is unwilling or unable to assume liability. (STRONGER 2013 Guidelines Section 3.1.d.)
Recommendation I.6.b.
The review team recommends that DEP conduct a workload analysis, as part of its program evaluation, to determine which program areas and geographic areas that additional staff may be needed in the future. (STRONGER 2013 Guidelines Section 4.2.3.2.)

2. Prohibit the use of diesel or similar substances in drilling and fracturing

On February 5, 2014 the EPA issued a memorandum, guidance document and other materials relative to the use of diesel fuel and similar substances in hydraulic fracturing. The EPA is permitting the use of diesel fuel and similar substances in both drilling and hydraulic fracturing. This is a primary example of where Pennsylvania can do better. Pennsylvania needs to do better. The Commonwealth has an obligation to balance the needs of industry with public health and safety, community, and the environment. Pennsylvania's unconventional shale gas resources lie largely beneath much of rural Pennsylvania, where many residents rely on private water wells and springs for their drinking water sources. The Department needs to consider all available technologies and the manner in which diesel fuel and similar substances may be utilized in the extraction of shale gas resources in rural Pennsylvania. The Department needs to create a regulatory framework that prohibits the use of diesel fuel and thus encourages the use of water resource friendly, non-toxic alternatives that will enable our water resources to be adequately protected.

During 2011, Tioga County, a county in our region had at least nine wells which have been hydraulically fractured using the CAS 8008-20-6 which is one of the five diesel CAS's noted by EPA on their Fact Sheet. http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/upload/epa816f14001.pdf Attached please find the associated Hydraulic Fracturing Fluid Product Component Information Disclosures as posted on FracFocus.

The use of diesel is a concern recently noted in the February 2014 EPA Fact Sheet, *"Diesel fuels may contain a number of chemicals of concern including benzene, toluene, ethylbenzene, and xylene compounds (BTEX). BTEX compounds are highly mobile in ground water and are regulated under the SDWA national primary drinking water regulations (NPDWRs) because of the risks they pose to human health."* http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/upload/epa816f14001.pdf

Diesel and other toxic chemicals may be avoided in drilling and fracturing as a result of environmentally friendly technological advances. Diesel alternatives such as hydro-carbon based fluids and synthetic fluids are available. These diesel alternatives are optimized to have properties similar to have properties similar to diesel to function as: fluid-loss additives, carrier fluid (for gelling additives) and winterizing agents for extreme cold/winter treatments. Both alternatives are said to be more environmentally and toxicologically benign than conventional diesel fuels. Several oil/gas producers and oilfield services companies currently employ or produce diesel-free substitutes in their chemicals. [http://www.gwpc.org/sites/default/files/event-sessions/Bergman_Ron_0.pdf slide 12]

As an example, Halliburton has the three Halliburton proprietary CleanSuite™ production enhancement technologies for both hydraulic fracturing and water treatment. http://www.halliburton.com/public/news/pubsdata/press_release/2011/corpnws_050211_1.html?SRC=ElPasoandHalliburton

In August of 2013, The Pennsylvania based Center for Sustainable Shale Development issued 14 performance standards. In part, Performance Standard No. 7 states *"Operators will not use diesel fuel in their hydraulic fracturing fluids."* Thus, there is reason that at least some operators are concerned about the use of diesel fuel in their subsurface operations.

Carrizo Oil & Gas Inc., operates within the Northern Tier Region. In February, 2012 Carrizo had a blowout at the MARCELLUS BAKER 4H WELL located in Forest Lake Township, Susquehanna County. As noted in the NOV, The department "strongly" recommended that Carrizo halt all fracturing operations in the state "until the cause of this problem and a solution are identified." Carrizo had a blowout March 15, 2013 on the YARASAVAGE well pad located in Washington Township, Wyoming County. On March 1, 2013 their MAZZARRA pad spilled 9,000 gallons of treated flowback of which some was contained in the basement of a nearby home. A home's basement is not a proper containment structure. We are still awaiting news of the final investigation results and the consent order agreement regarding these last two events.

Thus, we were very interested in Carrizo's representative's perspective when asked about CSSD's performance based standards. In response to the issuance of these performance based standards, Richard Hunter, vice president of investor relations for Carrizo Oil & Gas Inc., stated, *"We're a pretty small company," Hunter said Tuesday. "If this becomes industry standard, then, of course, we'll consider it. But we're already a licensed operator. Government agencies certify operators."* http://www.naturalgasintel.com/articles/print/4614-cssd-says-membership-will-grow-slowly-but-producers-cautious

In other words it is clear that some operators require a regulatory framework to move towards modern methods otherwise, they will be complacent.

This is another example where despite better practices an operator determines to do it 'their own way'. The purpose of regulations at times is to create a level playing field where public health and safety and the environment, thus our community at large are adequately protected. This is especially important when so many well pads and other facilities are located in close proximity to homes, schools and even our local hospitals. Industry trade groups, industry suggestions, and even industry peer pressure at times have had insufficient

results with all operators ceasing to utilize less than modern standards. However, unfortunate, the only recourse is to create regulation that eliminates poor choices of operations and provides a better pathway towards those that are of a higher quality. This is the manner in which we walk together towards reaching that delicate balance where all may thrive. Therefore, we recommend that the Department create the necessary regulatory framework that prohibits the use of diesel fuel and similar substances for drilling and hydraulic fracturing subsurface operations.

We appreciate the Department moving forward to codify Act 13's environmental protections. The codification of policies will strengthen the Department's ability to enforce compliance. The addition of new provisions will provide for more stringent regulations and environmental protections for operations located within and around our rural, farmland and forested communities which many times are in close proximity to our homes and schools. We strongly urge the Department to refrain from a two-tiered approach when creating a regulatory framework for both conventional and unconventional operations. This is a world class play; Pennsylvania is now expected to be the number two gas producing state in the nation. With a world class play, come world class obligations, first to the Department to ensure that our public health and safety, environment and communities are adequately protected with consideration to the needs of industry. Secondly, there is an ever increasing obligation upon the industry to be considerate and respectful of all our resources including environmental resources of air, water and soil, our communities and public health and safety. By working together, by working towards the center ground, we are confident that we can reach that delicate balance where all may thrive. This rulemaking process is one step in the right direction to make this world class play an example of how that delicate balance may

be reached. We request that all provisions apply to all existing and future well sites, wells and other facilities, as that is imperative to creating a better development plan, for providing measures that ensure our public health and safety, environment and communities are adequately protected, and it is an important step towards achieving the delicate balance where we all may thrive, including industry. We appreciate the opportunity to submit comments on this most important rulemaking which directly affects our region.

Sincerely,

Emily E. Krafjack

Emily E. Krafjack
President

WR-35

Date July 13, 2005
API # 47- 039 - 05714

State of West Virginia
Division of Environmental Protection
Section of Oil and Gas
Well Operator's Report of Well Work

Farm Name: Dennis & Christine Smartley Operator Well No.: Raymond City #11

LOCATION: Elevation: 1051.99' Quadrangle: Bancroft
District: Union County: Kanawha
Latitude: 6550' feet South of 38° DEG. 32' MIN. 30" SEC.
Longitude: 1068' feet West of 81° DEG. 45' MIN. 00" SEC.

Casing & Tubing Size	Used in Drilling	Left In Well	Cement Fill Up Cu. Ft.
13 3/8"	28'	28'	N/A
9 5/8"	586'	586'	280
7"	2311'	2311'	465
4 1/2"		5070'	350
2 3/8"		4904'	

Company: Cabot Oil & Gas Corporation
900 Lee Street East, Suite 500
Charleston, WV 25301

Agent: Thomas S. Liberatore
Inspector: Carlos Hively
Permit Issued: 3/30/2005
Well Work Commenced: April 10, 2005
Well Work Completed: May 10, 2005
Verbal Plugging:
Permission granted on:
Rotary X Cable
Total Depth (feet) 5085'
Fresh Water Depths (ft) 92'
Salt Water Depths (ft) None reported
Is coal being mined in area (Y / N) ? Y
Coal Depths (ft) 378'-380', 445'-447'

OPEN FLOW DATA

Producing Formation Marcellus Shale / Huron Shale Pay Zone Depth (ft) 5042'-4801' / 4381'-3866'

Gas: Initial Open Flow TSTM MCF/d Oil: Initial Open Flow 0 Bbl/d
Final Open Flow 348 (COMMINGLED) MCF/d Final Open Flow 0 Bbl/d
Time of open flow between initial and final tests 96 Hours
Static rock pressure 360 psig surface pressure after 14 Hours

Second Producing Formation Devonian Shale Pay Zone Depth (ft) 3334'-3306'

Gas: Initial Open Flow TSTM MCF/d Oil: Initial Open Flow 0 Bbl/d
Final Open Flow 348 (COMMINGLED) MCF/d Final Open Flow 0 Bbl/d
Time of open flow between initial and final tests 96 Hours
Static rock pressure 360 psig surface pressure after 14 Hours

NOTE: ON BACK OF THIS FORM PUT THE FOLLOWING: 1.) DETAILS OF PERFORATED INTERVALS, FRACTURING OR STIMULATING, PHYSICAL CHANGE, ETC. 2.) THE WELL LOG WHICH IS SYSTEMATIC DETAILED GEOLOGICAL RECORD OF ALL FORMATIONS, INCLUDING COAL ENCOUNTERED BY THE WELLBORE

For: CABOT OIL & GAS CORPORATION
By: [signature] Drilling Superintendent
Date: 7/22/05

RECEIVED
Office of Oil & Gas
Office of Chief
JUL 26 2005
WV Department of Environmental Protection

KAN 5714

AUG 26 2005

STAGE	PERFS	ACID 15% HCl	FOAM	SAND (lbs)	NITROGEN (scf)	BDP	ATP	MTP	ISIP
1-Marcellus Shale	5042-4801 (35)	250 gal	80Q	4,000	452,496	2476	2893	3104	2471
2-Huron Shale	4381-3866 (37)	500 gal	80Q	10,000	819,823	2410	2535	2640	1880
3-Devonian Shale	3334-3306 (29)	250 gal			404,725	1594	1650	1734	1300
4-Berea	2642-2656 (29)	500 gal	80Q	4,000	423,989	3207	3362	3537	2724

FORMATION	TOP	BOTTOM	REMARKS
Sand and Shale	0	378	
Coal	378	380	
Sand & Shale	380	445	
Coal	445	447	
Sand & Shale	447	860	
Sand	860	894	
Shale	894	904	
Sand	904	946	
Shale	946	967	
Sand	967	992	
Shale	992	1010	
Sand	1010	1026	
Silt & Shale	1026	1125	
Sand	1125	1250	
Sand & Shale	1250	1530	
Sand	1530	1570	
Silt & Sand	1570	1660	
Salt Sand	1660	1965	
Big Lime	1965	2161	
Shale	2161	2169	
Injun	2169	2212	
Silt & Sand	2212	2397	
Shale	2397	2624	
Sunbury Shale	2624	2642	
Berea Sand	2642	2656	
Shale	2656	3866	
Huron Shale	3866	4382	
Shale	4382	4765	
Rhinestreet Shale	4765	4992	
Marcellus Shale	4992	5045	
Onondaga	5045	5085	TD

AUG 2 6 2005

Environmental Assessment for 47-039-05714, Raymond City #11, Kanawha County, West Virginia

George Monk and Molly Schaffnit
Poca, West Virginia
November 2009

Description of Site

The site is immediately off of Harmon's Creek Road on the Kanawha County side of the Putnam and Kanawha County lines, north of Charleston. The well was drilled in 2005 to the Marcellus formation and that and two other Devonian shale formations were fractured according to the operator's completion report filed with the state.[1]

George originally visited the site in November 2008 but because of construction equipment parked on the pad (for a waterline being installed along Harmon's Creek Road) his observations were limited to the perimeter of the pad and the production equipment.[2]

We returned to the site with one of the surface owners on 20 July 2009. Our objective at that time was to try to determine the location of the pit and possible location of the land application of drill waste. What we found was a large area on the pad, north of the wellhead, where sections of thick black plastic were sticking up out of the ground. The exposed plastic surrounded an area that was bare of vegetation in some places, sparsely vegetated in others. The owner told us that this was where the pit had been located when the well was drilled. He also indicated north of the pad where he and his wife had observed a powdery "cement colored" substance on leaves and vegetation. This was the presumed land application area.

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[1] The well completion report is available online at http://downloads.wvgs.wvnet.edu/BatchInfo/kanawha/4703905714compO.tif.

[2] Photographs of the site taken in November 2008 are on the *Gas Well Study, 2008* portion of our website: http://members.citynet.net/sootypaws/Woods/gaswell/comments/otherwells/5714.html. A secondary containment dike for the condensate storage tank was constructed in October 2009.

We received permission from the surface owners and began to assess the site.[3]

Description of Pad and Surroundings

The cleared area for the pad was about 100 by 200 feet, oriented roughly west to east with the wellhead more or less in the center. There seems to have been little required in the leveling of the site as there was not a cut into a hillside. The fill slope was short and the sedimentation control along the northern edge of the site consisted of a branch and log barrier. A pipeline to a nearby compressor station passed along the northern edge of the site.

The pad had a slant and depressions. The highest part of the pad was at the southeast corner, above the paved Harmon's Creek Road. From south to north there was a slight downward slope with the lowest portion of the pad being where the pit had been. It was in this area where we observed standing water in the form of shallow puddles.

Vegetation coverage on the fill slope and the southeastern corner was the best on the site. There were areas not related to the exposed plastic perimeter where coverage was sparse, similar to what we've seen at other sites reclaimed at about the same time by this operator.

A steep hillside at the north of the pad drops to a hollow. About 326 feet from the well, according to our GPS, is a spring-fed cistern on the surface owners' property.

Exposed Plastic Perimeter

Exposed black plastic created a perimeter that was roughly 15 feet wide and 100 long. At the western end within this perimeter there was no vegetation at all. Vegetation became progressively less sparse towards the east.[4] There was a portion of thick steel cable emerging from approximately the center of the space within the perimeter of exposed plastic.

Soil in this area was a fine, tan colored clay. There were small patches of darker material showing and next to one of the exposed pieces of plastic this darker material had the appearance of drill waste -- dark gray, cement-like in appearance.

When the chloride test sample for S5 was collected, less than 2 inches below the surface a dark gray horizon was encountered, similar to the

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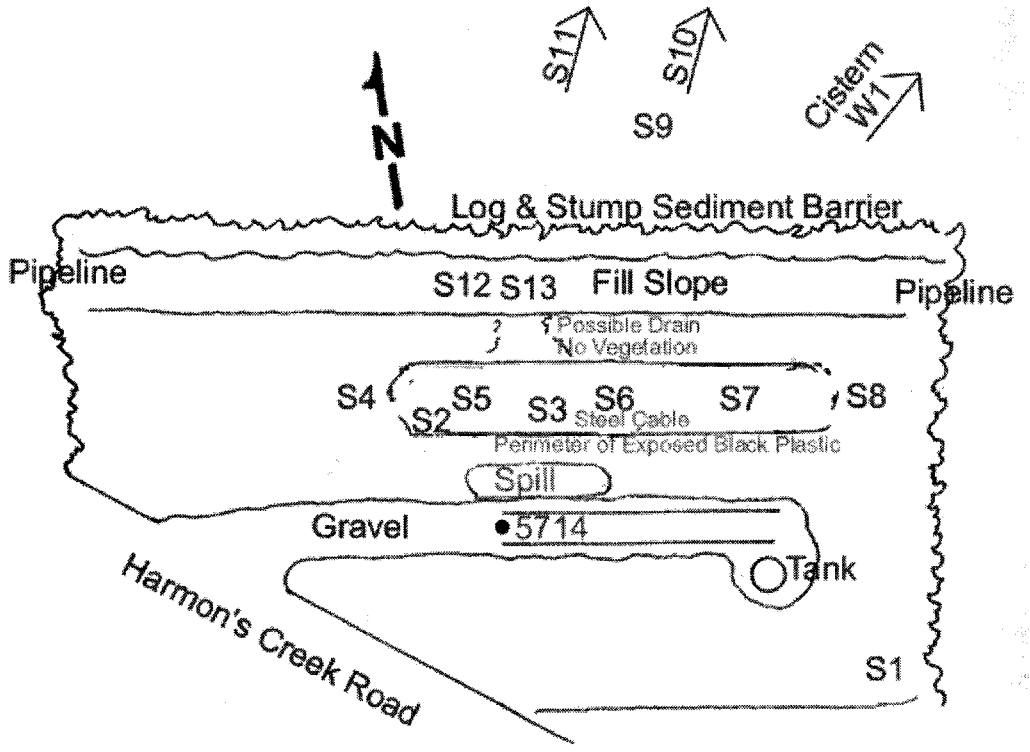
[3] The surface owners had a verbal agreement with the operator that all drill waste was to be disposed of off site. This was also the understanding of neighboring surface owners.

[4] The predominate form of vegetation on the pad is tall fescue grass. At least one variety of tall fescue is vulnerable to high chloride in soil which prohibits germination. See David A. Munn and Raymond Stewart, 1989, "Effect of Oil Well Brine on Germination and Seedling Growth of Several Crops," *Ohio Journal of Science.*

cement-like material. When the laboratory sample was collected at the same location as S5, the dark gray horizon extended from about 2 inches below the surface to as far was we excavated during sample collection, 6 inches. About a foot east of this location, there was dark gray colored soil on the surface. The only place when collecting samples where we encountered what we believe to be drill waste was within the exposed plastic perimeter.



Soil Testing

For preliminary soil and water testing we used Hach Quantab low range chloride test strips with an effective range of concentrations between 30 and 650 mg/l.[5] For lower concentration tests we consider Quantab 0.2 and 0.4 as trace and 0.6 and 0.8 as <30 mg/l chloride.

All but one of the samples collected were soil samples and were taken to try to assess two different issues. On the pad itself, soil samples were taken to try to determine the extent and nature of soil contamination in the pit area. Away from the pit area, soil samples were taken on the hillside below the pad on the north side to try to determine if this was the application area for liquid drill waste. All soil samples, except 5714-A for laboratory analysis, were taken from the surface.

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[5] A description of how we use the Quantab test strips is available on our website, George Monk and Molly Schaffnit, *Environmental Assessment -- Chloride Testing*, Sootypaws website.

One water grab sample was taken from the spring-fed cistern on the hillside below the pad to test the water for chloride.

Hach Quantab Soil Test Locations

During our initial visit to the site (20 July 2009) we tested the cistern's water (<30 mg/l chloride, sample W1) and took two soil samples from the pad within the exposed plastic perimeter where there was no vegetation. Those samples (S2 and S3) showed the presence of chloride at >650 mg/l.

A second visit to the site (on 26 July 2009) was made. After measuring the extent of the black plastic and bare and sparsely vegetated area, we created a traverse line through the length of this affected area, with markers set 28 feet apart. Five markers were set, with the central marker next to a piece of thick steel cable that projected from the soil's surface.[6] These are samples S4-S8 on the map. Samples S4 and S8 were taken outside the perimeter of exposed black plastic.

North of the pad, on the hillside below, three locations were tested (S9 - S11). According to our GPS these were roughly 116 to 216 feet from the wellhead.

On a third visit (6 August 2009) we tested two spots located on the fill slope of the pad (samples S12 and S13) to the north of the perimeter of exposed plastic, where we believed drainage from the pit area possibly was taking place. We also took samples for laboratory analysis in the same location at S5.

High Chloride Locations

The only soil locations that tested greater than a trace concentration of chloride were within the perimeter of exposed black plastic: the two initial soil tests S2 and S3 (>650 mg/l) and the later tests S5 (>650 mg/l), S6 (331 mg/l) and S7 (136 mg/l) along the traverse. One soil test, the easternmost sample on the traverse, S8, showed less than 30 mg/l (Quantab 0.6).

Low Chloride Locations

Soil tests carried out beyond the black plastic perimeter all showed just a trace of chloride or, at the eastern end of the traverse at S8, < 30 mg/l. The water grab sample from the cistern below the site tested at less than 30 mg/l (Quantab 0.8 on the scale of the test strip).

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[6] We have assumed that this is close to the center of the closed pit. We believe the piece of steel cable was used to puncture and hold the folded ends of pit liner while the pit contents were buried. We observed a similar piece of steel projecting above the surface of the closed pit of 47-079-01492, a well operated by a different company.

Table 1. Sample Locations and Chloride Concentrations

ID	Sample Location	Chloride
S1	Soil test sample from southeast corner of pad.	trace
S2	Soil test sample from north of well in area bare of vegetation, inside of exposed black plastic perimeter.	>650 mg/l
S3	Soil test sample from north of well in area bare of vegetation, inside of exposed black plastic perimeter.	>650 mg/l
S4	Soil test sample from westernmost point of traverse, outside of exposed black plastic perimeter.	trace
S5	Soil test sample 28 feet east of S4 on traverse, inside exposed black plastic perimeter.	>650 mg/l
S6	Soil test sample 28 feet east of S5 on traverse, inside exposed black plastic perimeter, next to piece of steel cable.	331 mg/l
S7	Soil test sample 28 feet east of S6 on traverse, inside exposed black plastic perimeter.	136 mg/l
S8	Soil test sample 28 feet east of S7 on traverse, outside exposed black plastic perimeter, at the easternmost end of the traverse.	<30 mg/l
S9	Soil test sample from wooded slope below pad.	trace
S10	Soil test sample from wooded slope below pad, further down slope than S9.	trace
S11	Soil test sample from wooded slope below pad, further down slope than S10.	trace
S12	Soil test sample from fill slope below northern edge of pad.	trace
S13	Soil test sample from fill slope below northern edge of pad, northeast of S12.	trace
5714-A	Soil sample for laboratory analysis, the same location as S5 but from 4-5 inches below the surface.	2,550 mg/l
W1	Water grab sample from spring-fed cistern downhill from pad.	<30 mg/l
Note: Samples taken from surface except where noted. Locations shown on map.		

Laboratory Analysis

We collected two samples of the pit material on 6 August 2009 and sent one to Pace Analytical Laboratories for analysis. The sample submitted to Pace (5714-A) was collected at between 4 and 5 inches below the surface,

where the material appeared to be entirely pit waste by its color and consistency. The sample was collected exactly from the same location as S5.

Table 2. Laboratory Analysis for 5714-A

	Concentration	CAS Number
Chloride	2550 mg/kg	16887-00-6
Arsenic	16 mg/kg	7440-38-2
Barium	203 mg/kg	7440-39-3
Cadmium	Not Detected	7440-43-9
Calcium	37100 mg/kg	7440-70-2
Chromium	27.9 mg/kg	7440-47-3
Lead	23.4 mg/kg	7439-92-1
Magnesium	6400 mg/kg	7439-95-4
Sodium	1230 mg/kg	7440-23-5
Radium 226	1.57 pCi/g	13982-63-3
Radium 228	1.35 pCi/g	15262-20-1

Site Assessment

The following assessment is based only on the concentrations of arsenic and lead found by the laboratory in the sample 5714-A, from within the perimeter of exposed plastic. Three of the metals are not considered a concern – calcium, magnesium and sodium – even though their concentrations were high.[7] Radium 226 and Radium 228 had concentrations within the normal background range.

The other five metals tested for were selected because they tend to appear in high concentrations in drill waste. Comparison with state soil background levels shows that the arsenic and lead concentrations were higher than the maximum.[8] Our assessment is based on these two metals, though we are also concerned with the high concentration of chloride in the sample. We believe chloride is directly impacting vegetation on the surface. As mobilizer and transporter of metals of concern, a high chloride concentration also has an influence on how we must assess the site.

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[7] The Sodium Adsorption Ratio (SAR) for the sample was 1.55.

[8] West Virginia soil background concentration levels are found in Table 2-3 of West Virginia Department of Environmental Protection, 2001, *West Virginia Voluntary Remediation and Redevelopment Act: Guidance Manual Version 2.1.*

The conceptual model for this site includes a number of factors, some already mentioned such as the presence of a spring-fed cistern down hill.[9] This cistern marks a point where nearby ground and surface water are hydrologically connected.

The Tolley residence and vegetable garden is about 200 feet from the laboratory sample location.[10] The spring-fed cistern is located about 300 feet in the opposite direction. City water has recently become available to residents, but some may still use similar cisterns.

The operator's well completion report notes fresh water 92 feet below the surface, though it is possible that a perched aquifer also exists much closer to the surface as is found elsewhere on this ridge. A mile away, the seasonal high water table is just a few feet from the surface.

After the well has finished production and equipment has been removed, the pad would make an ideal homesite because of its location next to the paved road and easy access to utilities. For this reason, and also because of the existing Tolley residence, we consider this a residential site.

We noted deer hoof prints in the vicinity of the hot spot and believe that deer are attracted to this location because of the salts in the soil which they ingest.[11]

Our assessment concerns are, as derived from the site description: possible effects to surface and ground water; possible effects to humans as they live, play and garden nearby (and possibly in the future, on the site); and possible ecological effects to wildlife and vegetation.

Table 3. Screening Levels for Soil to Ground Water

	Concentration mg/kg	EPA Soil to Groundwater mg/kg	WV Soil to Groundwater mg/kg
Arsenic	16	0.292	5.8
Lead	23.4	13.5	270

EPA's soil to groundwater screening levels shows there should be a concern for both arsenic and lead's concentrations in the sample. The EPA

[9] At this time the cistern is not being used for domestic or agricultural water supply.

[10] According to Annette Tolley, the well is 185 feet from her home and the vegetable garden is approximately 100 feet from the well.

[11] Taylor Campbell et al, 2004, "Unusual white-tailed deer movements to a gas well in the central Appalachians," *Wildlife Society Bulletin*. This study found deer traveling up to 6 km to visit a spot contaminated by gas well brine.

has two default Dilution-Attenuation Factors (DAF), a factor of 1 and a factor of 20.[12] The state's soil screening levels (taken from the de minimis soil screening levels in 60CSR3) use a DAF of 20 and still arsenic's concentration is almost 3 times higher.

There is a possibility that groundwater is being negatively affected by pit waste.

Table 4. Screening Levels for Residential Soil

	Concentration mg/kg	EPA Residential Soil mg/kg
Arsenic	16	0.389
Lead	23.4	400

Residential soil screening levels show that the arsenic concentration is 41 times the EPA's soil screening level. There is a strong possibility that current residents living nearby are being negatively affected by exposure to arsenic, and a similarly strong possibility that future residents on the site would be affected.

Table 5. Ecological Soil Screening Levels

	Concentration mg/kg	NOAA SQuiRTs Eco-SSL mg/kg	EPA Eco-SSL mg/kg
Arsenic	16	5.7 (mammals)	43 (avian) 2000 (mammals)
Lead	23.4	0.0537 (mammals)	11 (avian) 56 (mammals)

The NOAA ecological soil screening levels are much more protective than the EPA's and are based on recent research. There are no overriding reasons to use Eco-SSLs (such as endangered species or climax habitat), but we believe they need to be taken in consideration. Vegetation has been adversely affected and wildlife is attracted to the site by the presence of salts in the soil. Wildlife, such as deer, which is hunted and consumed by humans,

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[12] The DAF is a mathematical expression of the diminution of a contaminant's concentration upon entering a large aquifer. See [New Jersey Department of Environment Protection], 2008, *Guidance for the Determination of the Dilution-Attenuation Factor for the Impact to Ground Water Quality.*

provides an additional pathway of exposure for the chemicals of concern on the site.

Conclusions

Soil testing for chloride was not able to show whether or not land application of liquid pit waste occurred on the hillside to the north of the site. Land application, if it occurred, happened in 2005 and chloride doesn't reside in soil for long periods of time. Other types of soil testing, such as for elevated sodium or heavy metals, should be used in a situation of this sort.

Soil testing was able to show the extent of surface contamination from the contents of the pit but did not seem to show migration of the contamination to elsewhere on the site or to off the site. We were not able to visit the site during a heavy rain to see how the pad's drainage worked. It is possible that the pit area drains west, toward the Tolley residence across Harmon's Creek Road, instead of north. Diminishing surface chloride concentrations on the eastern segments of the traverse suggest that the pit's liner bottom may not be intact.

Heavy equipment and pipe parked on the pit area in 2008 and early 2009 while a water line was being installed along Harmon's Creek Road may have been a factor toward the disturbance of pit material and liner. The primary factor was the shallow and improper burial of the pit's contents. The shallow burial of pit waste and destruction of pit liner cover occurred earlier, during reclamation of the site by the operator after completion of the well. The highest point on the pad, where sample S1 was taken, was constructed of soil scraped from other parts of the pad as bits of torn black plastic and orange plastic fencing, used around the pit, attest. The state's regulations do not offer guidance, though other states require encapsulation of the pit's contents and a soil cover of at least 18 inches.[13] The Argonne National Laboratory recommends a minimum of 3 feet cover.[14]

Site assessment based on laboratory results from a single sample indicate that further assessment is required if the operator wishes to defer remediation. Screening levels for arsenic show that there's a concern for groundwater contamination and for the health of current nearby residents and potential future residents on the site.

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[13] Commonwealth of Pennsylvania, *Pennsylvania Code, Chapter 78.62*, subsections (A)17 and (A)18.

[14] Argonne National Laboratory, *Fact Sheet - Onsite Burial (Pits, Landfills). Drilling Waste Management.*

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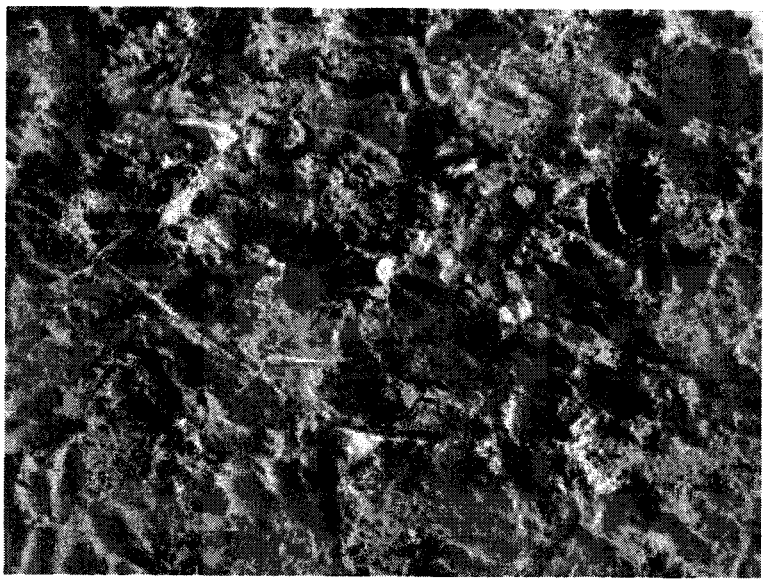
West Virginia Department of Environmental Protection. 2001. *West Virginia Voluntary Remediation and Redevelopment Act: Guidance Manual Version 2.1.* West Virginia Department of Environmental Protection, Office of Environmental Remediation. Table 2-3: Natural Background Levels of Inorganics in Soil in West Virginia and Surrounding Areas was used. http://www.wvdep.org/show_blob.cfm?ID=3200&Name=RemediationGuidanceVersion2-1.pdf

Photograph 1. View of the pit area showing perimeter of exposed black plastic (indicated by red circles). Molly is standing at easternmost edge of perimeter about 100 feet away. Sparsely vegetated area with highest chloride tests is in foreground. Photograph was taken looking east.

Photograph 2. Portion of exposed black plastic. Deer tracks are visible in foreground.



Photograph 3. Taken in October 2009, this photograph shows extensive deer activity at the location where samples S2, S3 and S5 were taken. The location for sample S5 and laboratory sample 5714-A is indicated by the green shotgun shell.

Photograph 4. Piece of steel cable emerging from surface. This is the approximate center of the perimeter of exposed black plastic and is the location of soil test S6.

Photograph 5. Traverse through pit area with locations of soil samples. Residence is on other side of Harmon's Creek Road. Photograph taken looking west.

Photograph 6. Looking up hillside below the well toward the northern edge of the pad. The hillside grade is approximately 36%. This photograph was taken from the cistern area.

Photograph 7. The spring-fed cistern below the well pad. The cement block cistern is covered with sheets of metal roofing and its overflow drainage is visible in the foreground.

Environmental Assessment for 47-039-02026, Raymond City #6, Kanawha County, West Virginia

George Monk and Molly Schaffnit
Poca, West Virginia
June 2009

Description of site
The well site is on a ridge between Harmon's Creek and Kelly's Creek Roads with its access road off Harmon's Creek Road.

The site is sparsely vegetated with a fringe of pine trees showing where the former cleared extent was. The well was drilled in the mid-1960s and according to state records never had a workover.

Significant clusters of deer tracks were used to identify possible locations of soil contamination from brine. Sparse vegetation on the site was an additional possible indicator.

In January 2008 the tank was allowed to overflow and crude petroleum and brine flowed down the hillside using an existing ditch. The tank in September 2008 had the required secondary containment constructed and the area was seeded. Several weeks later the road was graded, including part of the pad.

We began our examination of this site in September 2008.[1] Originally, we focused on equipment and maintenance of the site but beginning in 2009 we expanded our evaluation using this site as a way to develop our techniques for environmental assessment.[2]

The map shows approximate locations for soil sampling, features (such as supposed pit and "notch"), and scrap pipe and other metal from the operation of the well.

Soil testing
Soil samples were collected and testing was done by mixing an equal amount of soil sample with distilled water, shaking the mixture for 30

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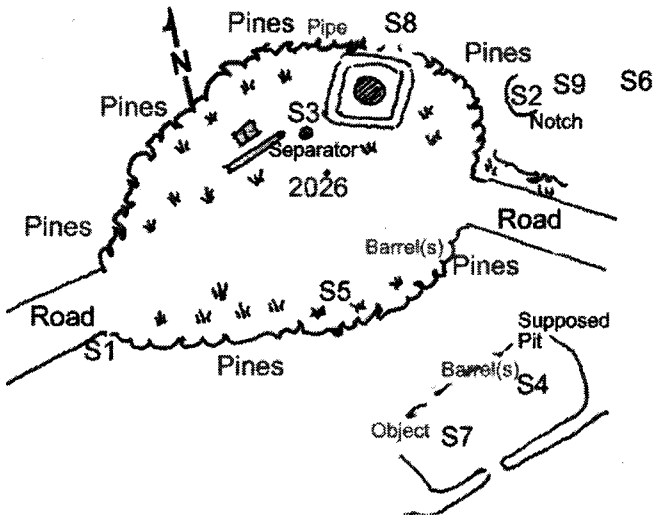
[1] Monk and Schaffnit, 2009, *Gas Well Study, 2008.*
[2] Monk and Schaffnit, "Environmental Assessment" web page.

seconds and letting settle. A Quantab chloride titrator test strip was used determine concentration of chlorides.[3]



Soil test locations

Soil testing occurred on two dates, 27 April 2009 and 20 May 2009. The first set of tests were locations called S1 through S4.[4] The second set of tests enhanced our understanding of the site and were S5 through S9.

Test locations were determined in order to see if we could evaluate the following issues we found in our evaluation. There were two locations (S2 and S3) that showed an unusually high number of deer tracks that we wanted to test to see if they had elevated chlorides.

Another location (S4 and S7) appeared to be an unfilled drilling waste pit. We wanted to see if soil there showed elevated chlorides.

The final set of tests examined the ditch behind the tank that was contaminated by brine and crude petroleum in January 2008 (S8); the hillside below the notch (S6 and S9), one of the heavily deer tracked spots we tested; and finally a test of the soil on the pad itself to see if a situation of elevated chlorides was a reason for lack of vegetation (S5).

High chloride locations

High chloride concentrations were found in the soil in three locations: the notch (136 mg/l), by the separator (136 mg/l) and the ditch contaminated

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[3] Otton and Zielinski, 2000, *Simple techniques for assessing impacts of oil and gas operations on Federal Lands: a field evaluation at Big South Fork National River and Recreation Area, Scott County, Tennessee (online edition).*

[4] Monk and Schaffnit, "47-039-02026" web page.

in January 2008 (42 mg/l). The notch (S2) and the separator (S3) locations showed evidence of unusual deer activity. High soil chlorides here seems to indicate that where we see high level deer tracking at other sites we can expect also to find elevated chlorides.

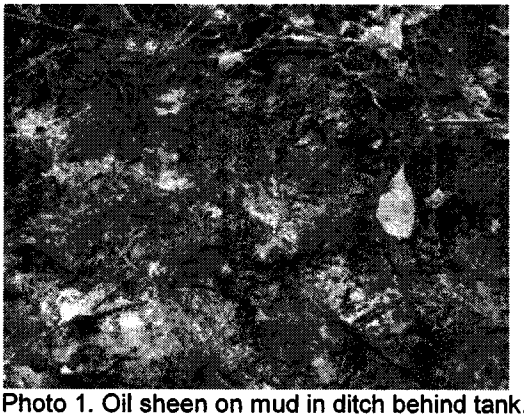

Photo 1. Oil sheen on mud in ditch behind tank.
Location of sample S8.

The contaminated ditch showed a lower concentration of chlorides (S8). When the soil sample was taken the petroleum contamination of the soil was still evident in the form of an oily sheen on the mud. This sample, after mixing with distilled water, had a strong condensate odor when the lid of the container was removed. The condensate odor never went away.

Trace and no chloride locations

Three locations showed no evidence of chlorides -- the control sample (S1) taken at the edge of the pad from undisturbed area; a sample from the pad itself (S5); and a sample down the hillside from the notch (S6).

Three samples showed trace chlorides (less than 30 mg/l, the lower limit of the test we used). Two of those samples were from the supposed pit (S4 and S7). The third sample was a short distance downhill from the notch. This sample was taken where a piece of black plastic from the notch rested (S9).

Testing didn't show one way or the other if the supposed pit was a drill waste pit or not. Chlorides would be expected but not necessarily high chlorides. At the same time, soil chlorides possibly would diminish over time in response to weathering.

The two tests down the hillside from the notch seem to indicate that there is no serious migration of chlorides from the site.

Conclusions

Our evaluation allows some conclusions but in other instances opens the door for more questions. Our testing seems to show that unusual deer tracking is a sign of brine contamination of soil. The contamination by the separator wasn't entirely unexpected because of the purpose of that piece of equipment.

Photo 2. Photograph of notch taken in February 2009 showing extensive deer tracking.

What has happened to cause the soil at the notch to be contaminated is one of the questions we'll try to resolve in the future. Fragments of black plastic (pit liner?) seem to indicate that it might be a workover pit but we've been told by the Office of Oil and Gas that no permitted workover has taken place at this site. Soil here always shows signs of moisture, unlike most areas of the pad, and that raises other questions. Does soil contaminated with chlorides hold moisture better? Is there something happening at this spot so that fluids (either water or brine) from below the surface are appearing here?

Poor vegetation on the pad probably isn't caused by chloride contamination, though chlorides do inhibit the germination and development of some varieties of Tall Fescue, the operator's seed of choice.[5] Vegetation problems are most likely due to the continual grading the road and pad receive -- at least once every year or two. The pad was seeded after construction in September 2008, but shows poor growth and no germination at all by the separator. The operator needs to change practices at this site so grass can grow properly.

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[5] Munn and Stewart, 1989, "Effect of Oil Well Brine on Germination and Seedling Growth of Several Crops."

Nothing was done by the operator to mitigate the effects of contamination of the soil by the crude petroleum and brine spill of January 2008. While eventually petroleum hydrocarbons will be broken down by soil bacteria, it appears that this will take years to happen. A question here is whether the high chloride content of the soil inhibits these bacteria.

Soil sample locations

ID	Description	Chlorides
S1	Control, edge of pad	none
S2	Notch	136 mg/l
S3	By separator	136 mg/l
S4	Supposed pit, 6 inches below surface	trace
S5	Pad, between well and supposed pit	none
S6	Below notch, further than S9	none
S7	Supposed pit, 17 inches below surface	trace
S8	Ditch, below tank	42 mg/l
S9	Below notch, between S2 and S6	trace
Note: Samples taken from surface except where noted. Locations shown on map.		

Sources

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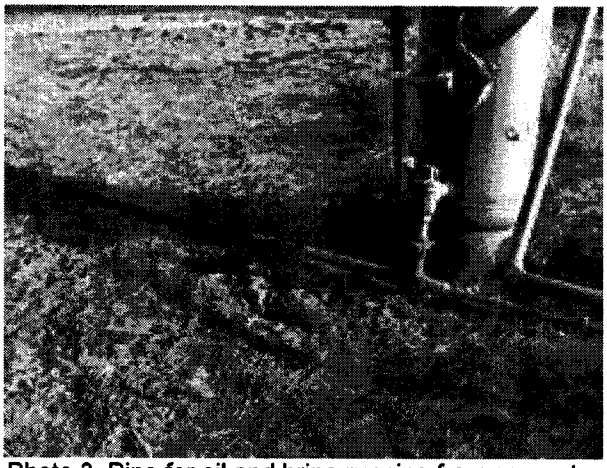

Photo 3. Pipe for oil and brine running from separator to tank (not shown). Great numbers of deer tracks along here to right up against separator.

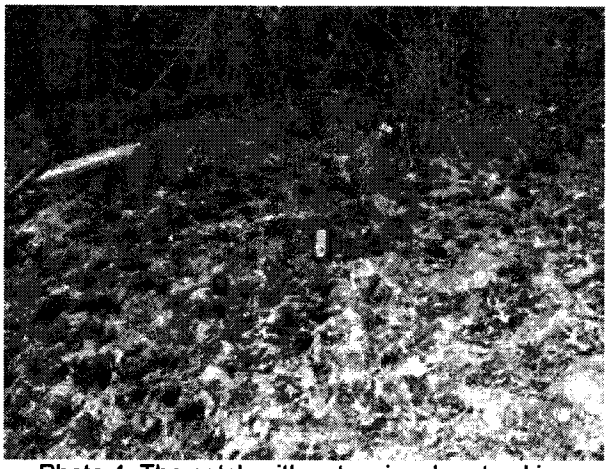

Photo 4. The notch with extensive deer tracking at time soil sample (S2) is being taken. GPS device is in center of photograph.

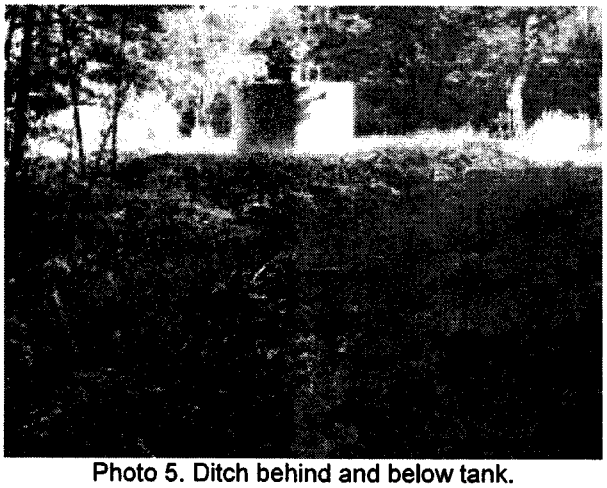

Photo 5. Ditch behind and below tank.
The ditch goes a short way down hillside.

Photo 6. This photo was taken in the supposed pit,
showing high bank. The bank appears
to be artificial.

Comments or questions? Email gmonk@citynet.net.

United States Environmental Protection Agency

Fact Sheet: Implementation of the Safe Drinking Water Act's Existing Requirements for Oil and Gas Hydraulic Fracturing Activities Using Diesel Fuels

The EPA has released an interpretive memorandum to clarify Underground Injection Control (UIC) program requirements under the Safe Drinking Water Act (SDWA), for underground injection of diesel fuels in hydraulic fracturing for oil and gas extraction. The agency has also released technical guidance containing recommendations for EPA permit writers to consider in implementing these UIC Class II requirements.

The EPA has developed the memorandum and technical guidance to achieve the following objectives:

- To explain that any owner or operator who injects diesel fuels in hydraulic fracturing for oil or gas extraction must obtain a UIC Class II permit before injection;
- To explain the agency's interpretation of the SDWA statutory term "diesel fuels" for permitting purposes; and,
- To describe existing UIC Class II program requirements for permitting underground injection of diesel fuels in hydraulic fracturing and to provide recommendations for the EPA's permit writers to consider in implementing these requirements to ensure protection of underground sources of drinking water (USDWs).

A key component of our nation's energy future is the safe, responsible development of oil and gas resources. If produced responsibly, natural gas has the potential to improve air quality, stabilize energy prices, and provide greater certainty about future energy reserves. The EPA is committed to working with co-regulators and other stakeholders to ensure that shale gas development occurs safely and responsibly and to encourage use of best practices.

The technical recommendations in the guidance are for EPA Regional Offices to consider when permitting diesel fuels hydraulic fracturing wells. EPA permit writers have the discretion to consider alternative approaches that are consistent with statutory and regulatory requirements. The EPA technical recommendations are consistent with best practices listed in state regulations, model guidelines and voluntary standards developed by industry and stakeholders. States and tribes responsible for issuing UIC and oil and gas well permits and/or updating regulations will find the recommendations useful in improving the protection of USDWs and public health wherever hydraulic fracturing is practiced.

The EPA recognizes that in addition to diesel fuels, other substances included in some hydraulic fracturing fluids contain of chemicals of concern. The EPA will work with states and industry to explore approaches to promote voluntary use of safer alternatives in hydraulic fracturing fluids.

REGULATION OF HYDRAULIC FRACTURING USING DIESEL FUELS

Underground injection of fluids through wells is subject to the requirements of the SDWA except where specifically excluded by the statute. In the 2005 Energy Policy Act, Congress revised the

SDWA definition of "underground injection" to specifically exclude hydraulic fracturing fluids from UIC regulation except where diesel fuels are used (SDWA Section 1421(d)(1)(B)). UIC regulations prohibit any underground injection except as authorized by rule or by permit. Thus, owners or operators who inject diesel fuels for hydraulic fracturing related to oil and gas operations must obtain a UIC permit before injection begins. Owners or operators injecting diesel fuels for hydraulic fracturing without a UIC permit may be subject to enforcement action under Section 1423 of the SDWA.

Hydraulic fracturing fluids are commonly a mixture of water, chemical additives and proppants. The types and concentrations of chemical additives and proppants used in hydraulic fracturing fluids vary depending on site-specific conditions and are usually tailored to needs of the project. In some instances diesel fuels have been used as an additive to achieve a variety of fluid properties. Diesel fuels may contain a number of chemicals of concern including benzene, toluene, ethylbenzene, and xylene compounds (BTEX). BTEX compounds are highly mobile in ground water and are regulated under the SDWA national primary drinking water regulations (NPDWRs) because of the risks they pose to human health.

WHEN DOES A HYDRAULIC FRACTURING ACTIVITY REQUIRE A UIC CLASS II PERMIT?

Owners or operators who inject diesel fuels for hydraulic fracturing related to oil and gas operations must obtain a UIC permit before injection begins. Consistent with the SDWA, the following five Chemical Abstract Service Registry Numbers (CASRN) represent the most appropriate interpretation of the statutory term "diesel fuels" to use for permitting diesel fuels hydraulic fracturing under the UIC Program nationwide, at this time:

- **68334-30-5 Primary Name: Fuels, diesel** Common Synonyms: Automotive diesel oil; Diesel fuel; Diesel oil (petroleum); Diesel oils; Diesel test fuel; Diesel fuels; Diesel fuel No. **1;** Diesel fuel [United Nations-North America (UN/NA) number 1993]; Diesel fuel oil; European Inventory ofExisting Commercial Chemical Substances (EINECS) 269-822-7.

- **68476-34-6 Primary Name: Fuels, diesel, No.2** Common Synonyms: Diesel fuel No. 2; Diesel fuels No. 2; EINECS 270-676-l ; No. 2 Diesel fuel.

- **68476-30-2 Primary Name: Fuel oil No. 2** Common Synonyms: Diesel fuel; Gas oil or diesel fuel or heating oil, light [UN 1202] No. 2 Home heating oils; API No.2 fuel oil; EINECS 270-671-4; Fuel oil No.2; Home heating oil No. 2; No.2 burner fuel; Distillate fuel oils, light; Fuel No. 2; Fuel oil (No. 1 ,2,4,5 or 6) [NA1993].

- **68476-31-3 Primary Name: Fuel oil, No. 4** Common Synonyms: Caswell No. 2 333AB; Cat cracker feed stock; EINECS 270-673-5; EPA Pesticide Chemical Code 063514; Fuel oil No. 4; Diesel fuel No. 4.

- **8008-20-6 Primary Name: Kerosene** Common Synonyms: JP-5 navy fuel/marine diesel fuel; Deodorized kerosene; JP5 Jet fuel; AF 100 (pesticide); Caswell No. 517; EINECS 232-366-4; EPA Pesticide Chemical Code 063501; Fuel oil No. 1; Fuels,

kerosine; Shell 140; Shell sol 2046; Distillate fuel oi ls, light; Kerosene, straight run; Kerosine, (petroleum); Several Others. The EPA may periodically update this list if new products are identified as diesel fuels.

Diesel fuels are sometimes used in oil and gas well development and production applications other than hydraulic fracturing. In non-injection applications the use of diesel fuels is not subject to UIC Class II permitting requirements because they are considered to be part of the well construction process and not injected for purposes of hydraulic fracturing.

TECHNCIAL GUIDANCE:

The revised guidance provides an overview of existing program requirements and technical recommendations pertaining to the follow aspects of Diesel Fuels hydraulic fracturing permitting:

- Permit application submission and review process
- Information submitted with the permit application
- Wells authorized under permits
- Permit duration and well closure
- Area of Review
- Well construction and mechanical integrity testing
- Well operations, monitoring and reporting
- Financial responsibility
- Public notification and environmental justice

FOR MORE INFORMATION:

- The guidance and other related documents are available at **Hydraulic Fracturing Under the Safe Drinking Water Act,** http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/hydraulic-fracturing.cfm.

- Information on agency-wide activities is available at **Natural Gas Extraction – Hydraulic Fracturing** provides more information on agency-wide activities, www.epa.gov/hydraulicfracturing.

Hydraulic Fracturing Fluid Product Component Information Disclosure

Fracture Date	8/5/2011
State:	PENNSYLVANIA
County:	Tioga
API Number:	37-117-20323
Operator Name:	Seneca Resources Corporation
Well Name and Number:	Pino 1H 50122
Longitude:	-77.152634
Latitude:	41.741102
Long/Lat Projection:	NAD83
Production Type:	Gas
True Vertical Depth (TVD):	6,600
Total Water Volume (gal)*:	4,327,773

Hydraulic Fracturing Fluid Composition:

Trade Name	Supplier	Purpose	Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient Concentration in Additive (% by mass)**	Maximum Ingredient Concentration in HF Fluid (% by mass)**	Comments
32% Hydrochloric Acid	Universal Well Services	Acid	Hydrogen Chloride	7647-01-0	32.00%	0.0471%	
NE-90	Universal Well Services	Non-Emulsifier	Methanol	67-56-1	60.00%	0.00015%	
			Isopropanol	67-63-0	10.00%	0.00003%	
			Heavy Aromatic Naphtha	64742-94-5	5.00%	0.00001%	
			Polyethylene Glycol	25322-68-3	5.00%	0.00001%	
			EO-C7-9-iso, C8-rich alcohols	78330-19-5	5.00%	0.00001%	
			EO-C9-11-iso, C10-rich alcohols	78330-20-8	5.00%	0.00001%	
			2-ethylhexanol	104-76-7	10.00%	0.00003%	
			Napthalene	91-20-3	1.00%	0.00000%	
Iron Sta IIC	Universal Well Services	Iron Control	Ethylene Glycol	107-21-1	30.00%	0.00032%	
Unihib A	Universal Well Services	Corrosion Inhibitor	Methanol	67-56-1	30.00%	0.00008%	
			C10-C16 Ethoxylated Alcohol	68002-97-1	30.00%	0.00008%	
			Isomeric Aromatic Ammonium Salt	Proprietary	10.00%	0.00003%	
			Petroleum Naphtha	64741-68-0	10.00%	0.00003%	
			Light Aromatic Solvent Naphtha	64742-95-6	10.00%	0.00003%	
			2-substituted Aromatic Amine Salt	Proprietary	5.00%	0.00001%	
			Kerosene	8008-20-6	5.00%	0.00001%	
			Hydrotreated light distillates	64742-47-8	5.00%	0.00001%	
			Kerosine (petroleum), hydrodesulfurized	64742-81-0	5.00%	0.00001%	
			Isopropyl Alcohol	67-63-0	5.00%	0.00001%	
			1,2,4- Trimethylbenzene	95-63-6	5.00%	0.00001%	
			1,3,5- Trimethylbenzene	108-67-8	1.00%	0.000003%	

			Diethylbenzene	25340-17-4	1.00%	0.000003%	
			Cumene	98-82-8	1.00%	0.000003%	
			Xylene	1330-20-7	1.00%	0.000003%	
			Formaldehyde	50-00-0	1.00%	0.000003%	
			Naphthalene	91-20-3	1.00%	0.000003%	
Unislik ST 50	Universal Well Services	Friction Reducer	Hydrotreated Light Distillate	64742-47-8	30.00%	0.01890%	
ScaleHib 100	Universal Well Services	Scale Inhibitor	Ethylene Glycol	107-21-1	60.00%	0.00990%	
Unigel CMHPG	Universal Well Services	Gelling Agent	No Hazardous Components			0.00000%	
LEB-10X	Universal Well Services	Enzyme Breaker	Ethylene Glycol	107-21-1	60.00%	0.00000%	
Sand (Proppant)	Universal Well Services	Proppant	Silica	14808-60-7	99.90%	12.25398%	
Water		Carrier/Base Fluid				87.61579%	
BioRid 20L	Tetra	Biocide	2,2-Dibromo-3-nitrilopropionamide	10222-01-2	20.00%	0.00003%	
			Sodium Bromide	7647-15-6	15.00%	0.00003%	

* Total Water Volume sources may include fresh water, produced water, and/or recycled water

** Information is based on the maximum potential for concentration and thus the total may be over 100%

All component information listed was obtained from the supplier's Material Safety Data Sheets (MSDS). As such, the Operator is not responsible for inaccurate and/or incomplete information. Any questions regarding the content of the MSDS should be directed to the supplier who provided it. The Occupational Safety and Health Administration's (OSHA) regulations govern the criteria for the disclosure of this information. Please note that Federal Law protects "proprietary", "trade secret", and "confidential business information" and the criteria for how this information is reported on an MSDS is subject to 29 CFR 1910.1200(i) and Appendix D.

Hydraulic Fracturing Fluid Product Component Information Disclosure

Fracture Date:	6/6/2011
State:	PENNSYLVANIA
County:	Tioga
API Number:	37-117-20777
Operator Name:	Seneca Resources Corporation
Well Name and Number:	Valides 4H 50263
Longitude:	-77.10455
Latitude:	41.739056
Long/Lat Projection:	NAD83
Production Type:	Gas
True Vertical Depth (TVD):	6,104
Total Water Volume (gal)*:	3,038,952

Hydraulic Fracturing Fluid Composition:

Trade Name	Supplier	Purpose	Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient Concentration in Additive (% by mass)**	Maximum Ingredient Concentration in HF Fluid (% by mass)**	Comments
32% Hydrochloric Acid	Universal Well Services	Acid	Hydrogen Chloride	7647-01-0	32.00%	0.04800%	
NE-90	Universal Well Services	Non-Emulsifier	Methanol	67-56-1	60.00%	0.00016%	
			Isopropanol	67-63-0	10.00%	0.00003%	
			Heavy Aromatic Naphtha	64742-94-5	5.00%	0.00001%	
			Polyethylene Glycol	25322-68-3	5.00%	0.00001%	
			EO-C7-9-iso, C8-rich alcohols	78330-19-5	5.00%	0.00001%	
			EO-C9-11-iso, C10-rich alcohols	78330-20-8	5.00%	0.00001%	
			2-ethylhexanol	104-76-7	10.00%	0.00003%	
			Napthalene	91-20-3	1.00%	0.00000%	
Iron Sta IIC	Universal Well Services	Iron Control	Ethylene Glycol	107-21-1	30.00%	0.00033%	
Unihib A	Universal Well Services	Corrosion Inhibitor	Methanol	67-56-1	30.00%	0.00009%	
			C10-C16 Ethoxylated Alcohol	68002-97-1	30.00%	0.00009%	
			Isomeric Aromatic Ammonium Salt	Proprietary	10.00%	0.00003%	
			Petroleum Naphtha	64741-68-0	10.00%	0.00003%	
			Light Aromatic Solvent Naphtha	64742-95-6	10.00%	0.00003%	
			2-substituted Aromatic Amine Salt	Proprietary	5.00%	0.00001%	
			Kerosene	8008-20-6	5.00%	0.00001%	
			Hydrotreated light distillates	64742-47-8	5.00%	0.00001%	
			Kerosine (petroleum), hydrodesulfurized	64742-81-0	5.00%	0.00001%	
			Isopropyl Alcohol	67-63-0	5.00%	0.00001%	
			1,2,4- Trimethylbenzene	95-63-6	5.00%	0.00001%	

			1,3,5- Trimethylbenzene	108-67-8	1.00%	0.00000%	
			Diethylbenzene	25340-17-4	1.00%	0.00000%	
			Cumene	98-82-8	1.00%	0.00000%	
			Xylene	1330-20-7	1.00%	0.00000%	
			Formaldehyde	50-00-0	1.00%	0.00000%	
			Naphthalene	91-20-3	1.00%	0.00000%	
Unislik ST 50	Universal Well Services	Friction Reducer	Hydrotreated Light Distillate	64742-47-8	30.00%	0.01530%	
ScaleHib 100	Universal Well Services	Scale Inhibitor	Ethylene Glycol	107-21-1	60.00%	0.01030%	
Unigel CMHPG	Universal Well Services	Gelling Agent	No Hazardous Components			0.00000%	
LEB-10X	Universal Well Services	Enzyme Breaker	Ethylene Glycol	107-21-1	60.00%	0.00001%	
Sand (Proppant)	Universal Well Services	Proppant	Silica	14808-60-7	99.90%	11.07900%	
Water		Carrier/Base Fluid				88.80171%	
BioRid 20L	Tetra	Biocide	2,2-Dibromo-3-nitrilopropionamide	10222-01-2	20.00%	0.00230%	
			Sodium Bromide	7647-15-6	15.00%	0.00170%	

* Total Water Volume sources may include fresh water, produced water, and/or recycled water

** Information is based on the maximum potential for concentration and thus the total may be over 100%

All component information listed was obtained from the supplier' s Material Safety Data Sheets (MSDS). As such, the Operator is not responsible for inaccurate and/or incomplete information. Any questions regarding the content of the MSDS should be directed to the supplier who provided it. The Occupational Safety and Health Administration' s (OSHA) regulations govern the criteria for the disclosure of this information. Please note that Federal Law protects "proprietary", "trade secret", and "confidential business information" and the criteria for how this information is reported on an MSDS is subject to 29 CFR 1910.1200(i) and Appendix D.

Hydraulic Fracturing Fluid Product Component Information Disclosure

Fracture Date:	6/17/2011
State:	PENNSYLVANIA
County:	Tioga
API Number:	37-117-20820
Operator Name:	Seneca Resources Corporation
Well Name and Number:	Valides 6H 50326
Longitude:	-77.104496
Latitude:	41.739281
Long/Lat Projection:	NAD83
Production Type:	Gas
True Vertical Depth (TVD):	5,941
Total Water Volume (gal)*:	5,180,910

Hydraulic Fracturing Fluid Composition:

Trade Name	Supplier	Purpose	Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient Concentration in Additive (% by mass)**	Maximum Ingredient Concentration in HF Fluid (% by mass)**	Comments
32% Hydrochloric Acid	Universal Well Services	Acid	Hydrogen Chloride	7647-01-0	32.00%	0.03567%	
NE-90	Universal Well Services	Non-Emulsifier	Methanol	67-56-1	60.00%	0.00012%	
			Isopropanol	67-63-0	10.00%	0.00002%	
			Heavy Aromatic Naphtha	64742-94-5	5.00%	0.00001%	
			Polyethylene Glycol	25322-68-3	5.00%	0.00001%	
			EO-C7-9-iso, C8-rich alcohols	78330-19-5	5.00%	0.00001%	
			EO-C9-11-iso, C10-rich alcohols	78330-20-8	5.00%	0.00001%	
			2-ethylhexanol	104-76-7	10.00%	0.00002%	
			Napthalene	91-20-3	1.00%	0.00000%	
Iron Sta IIC	Universal Well Services	Iron Control	Ethylene Glycol	107-21-1	30.00%	0.00024%	
Unihib A	Universal Well Services	Corrosion Inhibitor	Methanol	67-56-1	30.00%	0.00006%	
			C10-C16 Ethoxylated Alcohol	68002-97-1	30.00%	0.00006%	
			Isomeric Aromatic Ammonium Salt	Proprietary	10.00%	0.00002%	
			Petroleum Naphtha	64741-68-0	10.00%	0.00002%	
			Light Aromatic Solvent Naphtha	64742-95-6	10.00%	0.00002%	
			2-substituted Aromatic Amine Salt	Proprietary	5.00%	0.00001%	
			Kerosene	8008-20-6	5.00%	0.00001%	
			Hydrotreated light distillates	64742-47-8	5.00%	0.00001%	
			Kerosine (petroleum), hydrodesulfurized	64742-81-0	5.00%	0.00001%	
			Isopropyl Alcohol	67-63-0	5.00%	0.00001%	
			1,2,4- Trimethylbenzene	95-63-6	5.00%	0.00001%	

			1,3,5- Trimethylbenzene	108-67-8	1.00%	0.00000%	
			Diethylbenzene	25340-17-4	1.00%	0.00000%	
			Cumene	98-82-8	1.00%	0.00000%	
			Xylene	1330-20-7	1.00%	0.00000%	
			Formaldehyde	50-00-0	1.00%	0.00000%	
			Naphthalene	91-20-3	1.00%	0.00000%	
Unislik ST 50	Universal Well Services	Friction Reducer	Hydrotreated Light Distillate	64742-47-8	30.00%	0.01730%	
ScaleHib 100	Universal Well Services	Scale Inhibitor	Ethylene Glycol	107-21-1	60.00%	0.01260%	
Unigel CMHPG	Universal Well Services	Gelling Agent	No Hazardous Components			0.00000%	
LEB-10X	Universal Well Services	Enzyme Breaker	Ethylene Glycol	107-21-1	60.00%	0.00001%	
Sand (Proppant)	Universal Well Services	Proppant	Silica	14808-60-7	99.90%	11.83202%	
Water		Carrier/Base Fluid				88.05065%	
BioRid 20L	Tetra	Biocide	2,2-Dibromo-3-nitrilopropionamide	10222-01-2	20.00%	0.00276%	
			Sodium Bromide	7647-15-6	15.00%	0.00207%	

* Total Water Volume sources may include fresh water, produced water, and/or recycled water

** Information is based on the maximum potential for concentration and thus the total may be over 100%

All component information listed was obtained from the supplier' s Material Safety Data Sheets (MSDS). As such, the Operator is not responsible for inaccurate and/or incomplete information. Any questions regarding the content of the MSDS should be directed to the supplier who provided it. The Occupational Safety and Health Administration' s (OSHA) regulations govern the criteria for the disclosure of this information. Please note that Federal Law protects "proprietary", "trade secret", and "confidential business information" and the criteria for how this information is reported on an MSDS is subject to 29 CFR 1910.1200(i) and Appendix D.

Hydraulic Fracturing Fluid Product Component Information Disclosure

Fracture Date:	5/8/2011
State:	PENNSYLVANIA
County:	Tioga
API Number:	37-117-20853
Operator Name:	SENECA RESOURCES CORPORATION
Well Name and Number:	Lehmann 1H 50348
Longitude:	-77.137109
Latitude:	41.746623
Long/Lat Projection:	NAD83
Production Type:	Gas
True Vertical Depth (TVD):	6,380
Total Water Volume (gal)*:	3,412,497

Hydraulic Fracturing Fluid Composition:

Trade Name	Supplier	Purpose	Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient Concentration in Additive (% by mass)**	Maximum Ingredient Concentration in HF Fluid (% by mass)**	Comments
15% Hydrochloric Acid	Universal Well Services	Acid	Hydrogen Chloride	7647-01-0	15.00%	0.04860%	
NE-90	Universal Well Services	Non-Emulsifier	Methanol	67-56-1	60.00%	0.00016%	
			Isopropanol	67-63-0	10.00%	0.00003%	
			Heavy Aromatic Naphtha	64742-94-5	5.00%	0.00001%	
			Polyethylene Glycol	25322-68-3	5.00%	0.00001%	
			EO-C7-9-iso, C8-rich alcohols	78330-19-5	5.00%	0.00001%	
			EO-C9-11-iso, C10-rich alcohols	78330-20-8	5.00%	0.00001%	
			2-ethylhexanol	104-76-7	10.00%	0.00003%	
			Napthalene	91-20-3	1.00%	0.00000%	
Iron Sta IIC	Universal Well Services	Iron Control	Ethylene Glycol	107-21-1	30.00%	0.00033%	
Unihib A	Universal Well Services	Corrosion Inhibitor	Methanol	67-56-1	30.00%	0.00009%	
			C10-C16 Ethoxylated Alcohol	68002-97-1	30.00%	0.00009%	
			Isomeric Aromatic Ammonium Salt	Proprietary	10.00%	0.00003%	
			Petroleum Naphtha	64741-68-0	10.00%	0.00003%	
			Light Aromatic Solvent Naphtha	64742-95-6	10.00%	0.00003%	
			2-substituted Aromatic Amine Salt	Proprietary	5.00%	0.00001%	
			Kerosene	8008-20-6	5.00%	0.00001%	
			Hydrotreated light distillates	64742-47-8	5.00%	0.00001%	
			Kerosine (petroleum), hydrodesulfurized	64742-81-0	5.00%	0.00001%	
			Isopropyl Alcohol	67-63-0	5.00%	0.00001%	
			1,2,4- Trimethylbenzene	95-63-6	5.00%	0.00001%	

			1,3,5- Trimethylbenzene	108-67-8	1.00%	0.00000%	
			Diethylbenzene	25340-17-4	1.00%	0.00000%	
			Cumene	98-82-8	1.00%	0.00000%	
			Xylene	1330-20-7	1.00%	0.00000%	
			Formaldehyde	50-00-0	1.00%	0.00000%	
			Naphthalene	91-20-3	1.00%	0.00000%	
Unislik ST 50	Universal Well Services	Friction Reducer	Hydrotreated Light Distillate	64742-47-8	60.00%	0.02110%	
ScaleHib 100	Universal Well Services	Scale Inhibitor	Ethylene Glycol	107-21-1	60.00%	0.01230%	
Unigel CMHPG	Universal Well Services	Gelling Agent	No Hazardous Components			0.00000%	
LEB-10X	Universal Well Services	Enzyme Breaker	Ethylene Glycol	107-21-1	60.00%	0.00001%	
Sand (Proppant)	Universal Well Services	Proppant	Silica	14808-60-7	99.90%	12.29202%	
Water		Carrier/Base Fluid				87.56490%	
BioRid 102	Tetra	Biocide	Sulfamic acid, N-Bromo, sodium salt	1004542-84-0	10.20%	0.00131%	
			Di-bromo nitrilopropionamide	10222-01-2	18.30%	0.00235%	

* Total Water Volume sources may include fresh water, produced water, and/or recycled water

** Information is based on the maximum potential for concentration and thus the total may be over 100%

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Hydraulic Fracturing Fluid Product Component Information Disclosure

Fracture Date:	5/8/2011
State:	PENNSYLVANIA
County:	Tioga
API Number:	37-117-20855
Operator Name:	SENECA RESOURCES CORPORATION
Well Name and Number:	Lehmann 3H 50350
Longitude:	-77.137213
Latitude:	41.74665
Long/Lat Projection:	NAD83
Production Type:	Gas
True Vertical Depth (TVD):	6,519
Total Water Volume (gal)*:	3,150,741

Hydraulic Fracturing Fluid Composition:

Trade Name	Supplier	Purpose	Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient Concentration in Additive (% by mass)**	Maximum Ingredient Concentration in HF Fluid (% by mass)**	Comments
15% Hydrochloric Acid	Universal Well Services	Acid	Hydrogen Chloride	7647-01-0	15.00%	0.02570%	
NE-90	Universal Well Services	Non-Emulsifier	Methanol	67-56-1	60.00%	0.00008%	
			Isopropanol	67-63-0	10.00%	0.00001%	
			Heavy Aromatic Naphtha	64742-94-5	5.00%	0.00001%	
			Polyethylene Glycol	25322-68-3	5.00%	0.00001%	
			EO-C7-9-iso, C8-rich alcohols	78330-19-5	5.00%	0.00001%	
			EO-C9-11-iso, C10-rich alcohols	78330-20-8	5.00%	0.00001%	
			2-ethylhexanol	104-76-7	10.00%	0.00001%	
			Napthalene	91-20-3	1.00%	0.00000%	
Iron Sta IIC	Universal Well Services	Iron Control	Ethylene Glycol	107-21-1	30.00%	0.00018%	
Unihib A	Universal Well Services	Corrosion Inhibitor	Methanol	67-56-1	30.00%	0.00005%	
			C10-C16 Ethoxylated Alcohol	68002-97-1	30.00%	0.00005%	
			Isomeric Aromatic Ammonium Salt	Proprietary	10.00%	0.00002%	
			Petroleum Naphtha	64741-68-0	10.00%	0.00002%	
			Light Aromatic Solvent Naphtha	64742-95-6	10.00%	0.00002%	
			2-substituted Aromatic Amine Salt	Proprietary	5.00%	0.00001%	
			Kerosene	8008-20-6	5.00%	0.00001%	
			Hydrotreated light distillates	64742-47-8	5.00%	0.00001%	
			Kerosine (petroleum), hydrodesulfurized	64742-81-0	5.00%	0.00001%	
			Isopropyl Alcohol	67-63-0	5.00%	0.00001%	
			1,2,4- Trimethylbenzene	95-63-6	5.00%	0.00001%	

			1,3,5- Trimethylbenzene	108-67-8	1.00%	0.00000%	
			Diethylbenzene	25340-17-4	1.00%	0.00000%	
			Cumene	98-82-8	1.00%	0.00000%	
			Xylene	1330-20-7	1.00%	0.00000%	
			Formaldehyde	50-00-0	1.00%	0.00000%	
			Naphthalene	91-20-3	1.00%	0.00000%	
Unislik ST 50	Universal Well Services	Friction Reducer	Hydrotreated Light Distillate	64742-47-8	60.00%	0.01670%	
ScaleHib 100	Universal Well Services	Scale Inhibitor	Ethylene Glycol	107-21-1	60.00%	0.01090%	
Unigel CMHPG	Universal Well Services	Gelling Agent	No Hazardous Components			0.00000%	
LEB-10X	Universal Well Services	Enzyme Breaker	Ethylene Glycol	107-21-1	60.00%	0.00001%	
Sand (Proppant)	Universal Well Services	Proppant	Silica	14808-60-7	99.90%	13.11603%	
Water		Carrier/Base Fluid				86.78197%	
BioRid 102	Tetra	Biocide	Sulfamic acid, N-Bromo, sodium salt	1004542-84-0	10.20%	0.00133%	
			Di-bromo nitrilopropionamide	10222-01-2	18.30%	0.00239%	

* Total Water Volume sources may include fresh water, produced water, and/or recycled water

** Information is based on the maximum potential for concentration and thus the total may be over 100%

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Hydraulic Fracturing Fluid Product Component Information Disclosure

Fracture Date	2/27/2011
State:	Pennsylvania
County:	Tioga
API Number:	37-117-20856
Operator Name:	Seneca Resources
Well Name and Number:	DCNR 007 5H
Longitude:	-77.413052
Latitude:	41.81609
Long/Lat Projection:	NAD83
Production Type:	Gas
True Vertical Depth (TVD):	6,700
Total Water Volume (gal)*:	4,474,050

Hydraulic Fracturing Fluid Composition:

Trade Name	Supplier	Purpose	Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient Concentration in Additive (% by mass)**	Maximum Ingredient Concentration in HF Fluid (% by mass)**	Comments
Water		Carrier/Base Fluid				88.36813%	
Sand (Proppant)		Proppant	Silica	14808-60-7	99.90%	11.31837%	
15% Hydrochloric Acid	Universal Well Services	Acid	Hydrogen Chloride	7647-01-0	15.00%	0.24080%	
NE-90	Universal Well Services	Non-Emulsifier	Methanol	67-56-1	60.00%	0.00079%	
			Isopropanol	67-63-0	10.00%	0.00013%	
			Heavy Aromatic Naphtha	64742-94-5	5.00%	0.00007%	
			Polyethylene Glycol	25322-68-3	5.00%	0.00007%	
			EO-C7-9-iso, C8-rich alcohols	78330-19-5	5.00%	0.00007%	
			EO-C9-11-iso, C10-rich alcohols	78330-20-8	5.00%	0.00007%	
			2-ethylhexanol	104-76-7	10.00%	0.00013%	
			Napthalene	91-20-3	1.00%	0.00001%	
Iron Sta IIC	Universal Well Services	Iron Control	Ethylene Glycol	107-21-1	30.00%	0.00164%	
Unihib A	Universal Well Services	Corrosion Inhibitor	Methanol	67-56-1	30.00%	0.00043%	
			C10-C16 Ethoxylated Alcohol	68002-97-1	30.00%	0.00043%	
			Isomeric Aromatic Ammonium Salt	Proprietary	10.00%	0.00014%	
			Petroleum Naphtha	64741-68-0	10.00%	0.00014%	
			Light Aromatic Solvent Naphtha	64742-95-6	10.00%	0.00014%	
			2-substituted Aromatic Amine Salt	Proprietary	5.00%	0.00007%	
			Kerosene	8008-20-6	5.00%	0.00007%	
			Hydrotreated light distillates	64742-47-8	5.00%	0.00007%	
			Kerosine (petroleum), hydrodesulfurized	64742-81-0	5.00%	0.00007%	

			Isopropyl Alcohol	67-63-0	5.00%	0.00007%	
			1,2,4- Trimethylbenzene	95-63-6	5.00%	0.00007%	
			1,3,5- Trimethylbenzene	108-67-8	1.00%	0.00001%	
			Diethylbenzene	25340-17-4	1.00%	0.00001%	
			Cumene	98-82-8	1.00%	0.00001%	
			Xylene	1330-20-7	1.00%	0.00001%	
			Formaldehyde	50-00-0	1.00%	0.00001%	
			Naphthalene	91-20-3	1.00%	0.00001%	
FRP-121	Universal Well Services	Friction Reducer	No Hazardous Components				
ScaleHib 100	Universal Well Services	Scale Inhibitor	Ethylene Glycol	107-21-1	60.00%	0.01470%	
Unigel CMHPG	Universal Well Services	Gelling Agent	No Hazardous Components				
LEB-10X	Universal Well Services	Enzyme Breaker	Ethylene Glycol	107-21-1	60.00%	0.00001%	

* Total Water Volume sources may include fresh water, produced water, and/or recycled water

** Information is based on the maximum potential for concentration and thus the total may be over 100%

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Hydraulic Fracturing Fluid Product Component Information Disclosure

Fracture Date	4/18/2011
State:	PENNSYLVANIA
County:	Tioga
API Number:	37-117-20890
Operator Name:	Seneca Resources Corporation
Well Name and Number:	Steinmetz 3H 50352
Longitude:	-77.158061
Latitude:	41.727019
Long/Lat Projection:	NAD83
Production Type:	Gas
True Vertical Depth (TVD):	6,803
Total Water Volume (gal)*:	3,645,558

Hydraulic Fracturing Fluid Composition:

Trade Name	Supplier	Purpose	Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient Concentration in Additive (% by mass)**	Maximum Ingredient Concentration in HF Fluid (% by mass)**	Comments
32% Hydrochloric Acid	Universal Well Services	Acid	Hydrogen Chloride	7647-01-0	32.00%	0.09059%	
NE-90	Universal Well Services	Non-Emulsifier	Methanol	67-56-1	60.00%	0.00030%	
			Isopropanol	67-63-0	10.00%	0.00005%	
			Heavy Aromatic Naphtha	64742-94-5	5.00%	0.00002%	
			Polyethylene Glycol	25322-68-3	5.00%	0.00002%	
			EO-C7-9-iso, C8-rich alcohols	78330-19-5	5.00%	0.00002%	
			EO-C9-11-iso, C10-rich alcohols	78330-20-8	5.00%	0.00002%	
			2-ethylhexanol	104-76-7	10.00%	0.00005%	
			Napthalene	91-20-3	1.00%	0.00000%	
Iron Sta IIC	Universal Well Services	Iron Control	Ethylene Glycol	107-21-1	30.00%	0.00062%	
Unihib A	Universal Well Services	Corrosion Inhibitor	Methanol	67-56-1	30.00%	0.00016%	
			C10-C16 Ethoxylated Alcohol	68002-97-1	30.00%	0.00016%	
			Isomeric Aromatic Ammonium Salt	Proprietary	10.00%	0.00005%	
			Petroleum Naphtha	64741-68-0	10.00%	0.00005%	
			Light Aromatic Solvent Naphtha	64742-95-6	10.00%	0.00005%	
			2-substituted Aromatic Amine Salt	Proprietary	5.00%	0.00003%	
			Kerosene	8008-20-6	5.00%	0.00003%	
			Hydrotreated light distillates	64742-47-8	5.00%	0.00003%	
			Kerosine (petroleum), hydrodesulfurized	64742-81-0	5.00%	0.00003%	
			Isopropyl Alcohol	67-63-0	5.00%	0.00003%	
			1,2,4- Trimethylbenzene	95-63-6	5.00%	0.00003%	

			1,3,5- Trimethylbenzene	108-67-8	1.00%	0.00001%	
			Diethylbenzene	25340-17-4	1.00%	0.00001%	
			Cumene	98-82-8	1.00%	0.00001%	
			Xylene	1330-20-7	1.00%	0.00001%	
			Formaldehyde	50-00-0	1.00%	0.00001%	
			Naphthalene	91-20-3	1.00%	0.00001%	
Unislik ST 50	Universal Well Services	Friction Reducer	Hydrotreated Light Distillate	64742-47-8	30.00%	0.01530%	
ScaleHib 100	Universal Well Services	Scale Inhibitor	Ethylene Glycol	107-21-1	60.00%	0.01050%	
Unigel CMHPG	Universal Well Services	Gelling Agent	No Hazardous Components			0.00000%	
LEB-10X	Universal Well Services	Enzyme Breaker	Ethylene Glycol	107-21-1	60.00%	0.00001%	
Sand (Proppant)	Universal Well Services	Proppant	Silica	14808-60-7	99.90%	11.86075%	
Water		Carrier/Base Fluid				87.96751%	
BioRid 20L	Tetra	Biocide	2,2-Dibromo-3-nitrilopropionamide	10222-01-2	20.00%	0.00500%	
			Sodium Bromide	7647-15-6	15.00%	0.00375%	
FRP-121	Universal Well Services	Friction Reducer	No Hazardous Components				

* Total Water Volume sources may include fresh water, produced water, and/or recycled water

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Hydraulic Fracturing Fluid Product Component Information Disclosure

Fracture Date	7/31/2011
State:	PENNSYLVANIA
County:	Tioga
API Number:	37-117-20991
Operator Name:	Seneca Resources Corporation
Well Name and Number:	Pino 2H 50123
Longitude:	-77.14717
Latitude:	41.73266
Long/Lat Projection:	NAD83
Production Type:	Gas
True Vertical Depth (TVD):	6,660
Total Water Volume (gal)*:	3,819,058

Hydraulic Fracturing Fluid Composition:

Trade Name	Supplier	Purpose	Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient Concentration in Additive (% by mass)**	Maximum Ingredient Concentration in HF Fluid (% by mass)**	Comments
32% Hydrochloric Acid	Universal Well Services	Acid	Hydrogen Chloride	7647-01-0	32.00%	0.0637%	
NE-90	Universal Well Services	Non-Emulsifier	Methanol	67-56-1	60.00%	0.00021%	
			Isopropanol	67-63-0	10.00%	0.00003%	
			Heavy Aromatic Naphtha	64742-94-5	5.00%	0.00002%	
			Polyethylene Glycol	25322-68-3	5.00%	0.00002%	
			EO-C7-9-iso, C8-rich alcohols	78330-19-5	5.00%	0.00002%	
			EO-C9-11-iso, C10-rich alcohols	78330-20-8	5.00%	0.00002%	
			2-ethylhexanol	104-76-7	10.00%	0.00003%	
			Napthalene	91-20-3	1.00%	0.00000%	
Iron Sta IIC	Universal Well Services	Iron Control	Ethylene Glycol	107-21-1	30.00%	0.00043%	
Unihib A	Universal Well Services	Corrosion Inhibitor	Methanol	67-56-1	30.00%	0.00011%	
			C10-C16 Ethoxylated Alcohol	68002-97-1	30.00%	0.00011%	
			Isomeric Aromatic Ammonium Salt	Proprietary	10.00%	0.00004%	
			Petroleum Naphtha	64741-68-0	10.00%	0.00004%	
			Light Aromatic Solvent Naphtha	64742-95-6	10.00%	0.00004%	
			2-substituted Aromatic Amine Salt	Proprietary	5.00%	0.00002%	
			Kerosene	8008-20-6	5.00%	0.00002%	
			Hydrotreated light distillates	64742-47-8	5.00%	0.00002%	
			Kerosine (petroleum), hydrodesulfurized	64742-81-0	5.00%	0.00002%	
			Isopropyl Alcohol	67-63-0	5.00%	0.00002%	
			1,2,4- Trimethylbenzene	95-63-6	5.00%	0.00002%	
			1,3,5- Trimethylbenzene	108-67-8	1.00%	0.000004%	

			Diethylbenzene	25340-17-4	1.00%	0.000004%	
			Cumene	98-82-8	1.00%	0.000004%	
			Xylene	1330-20-7	1.00%	0.000004%	
			Formaldehyde	50-00-0	1.00%	0.000004%	
			Naphthalene	91-20-3	1.00%	0.000004%	
Unislik ST 50	Universal Well Services	Friction Reducer	Hydrotreated Light Distillate	64742-47-8	30.00%	0.018900%	
ScaleHib 100	Universal Well Services	Scale Inhibitor	Ethylene Glycol	107-21-1	60.00%	0.006600%	
Unigel CMHPG	Universal Well Services	Gelling Agent	No Hazardous Components			0.00000%	
LEB-10X	Universal Well Services	Enzyme Breaker	Ethylene Glycol	107-21-1	60.00%	0.00001%	
Sand (Proppant)	Universal Well Services	Proppant	Silica	14808-60-7	99.90%	12.64719%	
Water		Carrier/Base Fluid				87.21084%	
BioRid 20L	Tetra	Biocide	2,2-Dibromo-3-nitrilopropionamide	10222-01-2	20.00%	0.00003%	
			Sodium Bromide	7647-15-6	15.00%	0.00002%	

* Total Water Volume sources may include fresh water, produced water, and/or recycled water

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Hydraulic Fracturing Fluid Product Component Information Disclosure

Fracture Date:	7/31/2011
State:	PENNSYLVANIA
County:	Tioga
API Number:	37-117-21220
Operator Name:	Seneca Resources Corporation
Well Name and Number:	Pino 11H-E 50545
Longitude:	-77.140777
Latitude:	41.728
Long/Lat Projection:	NAD83
Production Type:	Gas
True Vertical Depth (TVD):	6,739
Total Water Volume (gal)*:	5,874,651

Hydraulic Fracturing Fluid Composition:

Trade Name	Supplier	Purpose	Ingredients	Chemical Abstract Service Number (CAS #)	Maximum Ingredient Concentration in Additive (% by mass)**	Maximum Ingredient Concentration in HF Fluid (% by mass)**	Comments
32% Hydrochloric Acid	Universal Well Services	Acid	Hydrogen Chloride	7647-01-0	32.00%	0.0557%	
NE-90	Universal Well Services	Non-Emulsifier	Methanol	67-56-1	60.00%	0.00018%	
			Isopropanol	67-63-0	10.00%	0.00003%	
			Heavy Aromatic Naphtha	64742-94-5	5.00%	0.00002%	
			Polyethylene Glycol	25322-68-3	5.00%	0.00002%	
			EO-C7-9-iso, C8-rich alcohols	78330-19-5	5.00%	0.00002%	
			EO-C9-11-iso, C10-rich alcohols	78330-20-8	5.00%	0.00002%	
			2-ethylhexanol	104-76-7	10.00%	0.00003%	
			Napthalene	91-20-3	1.00%	0.00000%	
Iron Sta IIC	Universal Well Services	Iron Control	Ethylene Glycol	107-21-1	30.00%	0.00038%	
Unihib A	Universal Well Services	Corrosion Inhibitor	Methanol	67-56-1	30.00%	0.00010%	
			C10-C16 Ethoxylated Alcohol	68002-97-1	30.00%	0.00010%	
			Isomeric Aromatic Ammonium Salt	Proprietary	10.00%	0.00003%	
			Petroleum Naphtha	64741-68-0	10.00%	0.00003%	
			Light Aromatic Solvent Naphtha	64742-95-6	10.00%	0.00003%	
			2-substituted Aromatic Amine Salt	Proprietary	5.00%	0.00002%	
			Kerosene	8008-20-6	5.00%	0.00002%	
			Hydrotreated light distillates	64742-47-8	5.00%	0.00002%	
			Kerosine (petroleum), hydrodesulfurized	64742-81-0	5.00%	0.00002%	
			Isopropyl Alcohol	67-63-0	5.00%	0.00002%	
			1,2,4- Trimethylbenzene	95-63-6	5.00%	0.00002%	
			1,3,5- Trimethylbenzene	108-67-8	1.00%	0.000003%	

			Diethylbenzene	25340-17-4	1.00%	0.000003%	
			Cumene	98-82-8	1.00%	0.000003%	
			Xylene	1330-20-7	1.00%	0.000003%	
			Formaldehyde	50-00-0	1.00%	0.000003%	
			Naphthalene	91-20-3	1.00%	0.000003%	
Unislik ST 50	Universal Well Services	Friction Reducer	Hydrotreated Light Distillate	64742-47-8	30.00%	0.019800%	
ScaleHib 100	Universal Well Services	Scale Inhibitor	Ethylene Glycol	107-21-1	60.00%	0.011800%	
Unigel CMHPG	Universal Well Services	Gelling Agent	No Hazardous Components			0.00000%	
LEB-10X	Universal Well Services	Enzyme Breaker	Ethylene Glycol	107-21-1	60.00%	0.00001%	
Sand (Proppant)	Universal Well Services	Proppant	Silica	14808-60-7	99.90%	11.80846%	
Water		Carrier/Base Fluid				88.04645%	
BioRid 20L	Tetra	Biocide	2,2-Dibromo-3-nitrilopropionamide	10222-01-2	20.00%	0.00002%	
			Sodium Bromide	7647-15-6	15.00%	0.00002%	

* Total Water Volume sources may include fresh water, produced water, and/or recycled water

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