Regulatory Analysis Form

Regulatory Analysis Form (Completed by Promulgating Agency) **(All Comments submitted on this regulation will appear on IRRC's website)**	***INDEPENDENT REGULATORY REVIEW COMMISSION***
(1) Agency Department of Environmental Protection	
(2) Agency Number: Identification Number: #7-484	IRRC Number**:** 3042
(3) PA Code Cite: 25 *Pa. Code* Chapters 78 and 78a	
(4) Short Title: Environmental Protection Performance Standards at Oil & Gas Well Sites	
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(6) Type of Rulemaking (check applicable box): ☐ Proposed Regulation ☒ Final Regulation ☐ Final Omitted Regulation	☐ Emergency Certification Regulation; ☐ Certification by the Governor ☐ Certification by the Attorney General

Contents

Question 7

(7) Briefly explain the regulation in clear and nontechnical language. (100 words or less)

This regulation relates to surface activities at conventional and unconventional well sites. The purpose of this regulation is to update the performance standards for surface activities at conventional and unconventional well sites to ensure that these activities are conducted in a manner that protects the health, safety, and environment and property of Pennsylvania citizens consistent with the environmental laws that provide authority for this final-form rulemaking.

These regulations represent the first update to rules governing surface activities associated with the development of oil and gas wells since 2001, and implements the 2012 Oil and Gas Act. The final rulemaking also separates the regulation into two Chapters governing conventional well development (Chapter 78) and unconventional well development (Chapter 78a).

Major areas of the rulemaking in both Chapters 78 and 78a include public resource impact screening, water supply replacement standards, waste management and disposal, and establishing identification and select monitoring of wells proximal to hydraulic fracturing activities. Other new regulations covering both conventional and unconventional operations include standards for well development impoundments; a process for the closure or waste permitting for wastewater impoundments; onsite wastewater processing, site restoration, borrow pits and reporting and remediating releases.

The conventional Chapter 78 contains several conventional well-specific rules including, road-spreading of brine; while the unconventional Chapter 78a contains several unconventional well-specific rules including, the containment of regulated substances; oil and gas gathering pipelines, well development pipelines and water management plans.

Question 8

(8) State the statutory authority for the regulation. Include specific statutory citation.

This final-form rulemaking is being made under the authority of Sections 3202, 3215(e), 3218(a), 3218.2(a)(4), 3218.4(c), and 3274 of the 2012 Oil and Act (58 Pa.C.S. §§ 3202, 3215(e), 3218(a), 3218.2(a)(4), 3218.4(c), 3274); Section 5 of the Clean Streams Law (35 P.S. § 691.5); Section 105 of the Solid Waste Management Act (35 P.S. § 6018.105); Section 5 of the Dam Safety and Encroachments Act (32 P.S. § 693.5); Section 104 of the Pennsylvania Land Recycling and Environmental Remediation Standards Act (35 P.S. § 6026.104); Sections 301 and 302 of the Radiation Protection Act (35 P.S. §§ 7110.301 and 7110.302); Section 3 of the Unconventional Well Report Act (58 P.S. § 1003); Section 1741.1-E of the act of July 10, 2014 (P.L. 1053, No. 126) (72 P.S. § 1741.1-E); and Sections 1917-A and 1920-A of The Administrative Code of 1929 (71 P.S. §§ 510-17, 510-20).

Question 9

(9) Is the regulation mandated by any federal or state law or court order, or federal regulation? Are there any relevant state or federal court decisions? If yes, cite the specific law, case or regulation as well as, any deadlines for action.

A number of the provisions in the final rulemaking are mandated by the 2012 Oil and Gas Act (58 Pa.C.S. §§ 3201—3274) including the following:

- Establish a streamlined process for addressing potential impacts to public resources (§ 3215 (c) & § 3215 (e)).
- Require the landowner to be notified of the implications of refusing to let operators take a pre-drill water supply sample (§ 3211(b.1)).
- Establish water supply replacement quality standards (§ 3218).
- Require well site tanks to meet the applicable corrosion control requirements of the Department's storage tank regulations (§ 3218.4(b)).
- Require all buried metallic pipelines to be installed and placed in operation in accordance with Federal pipeline corrosion control requirements (§ 3218.4(a)).
- Establish secondary containment requirements for regulated substances at unconventional well sites (§ 3218.2).
- Codify water management plan requirements (§ 3211(m)).
- Require well construction reports to include the country of origin of the well casing (§ 3222(b.1)(2)(ii)).

Several other provisions in the final rulemaking are required by or cross-reference other applicable statutes and regulations administered by the Department, including:

- Reporting and remediating spills and releases (25 Pa. Code § 91.33 (incidents causing or threatening pollution), § 6026.106(a)).
- Solid Waste Management Act (35 P.S. § 6018.101 et seq.); remediation of improperly disposed solid wastes and 25 Pa. Code Chapter 287.
- Land Recycling and Environmental Remediation Standards Act (35 P.S. § 6026.101, et seq.) and 25 Pa. Code Chapter 250.
- Water resources general provisions requirements in 25 Pa. Code Chapter 91.
- Water quality standards and antidegradation requirements in 25 Pa. Code Chapter 93.
- Wastewater treatment requirements in 25 Pa. Code Chapters 91 – 93 and 95.
- Erosion and sediment control and stormwater management requirements in 25 Pa. Code Chapter 102.
- Management of watercourses, wetlands and bodies of water in 25 Pa. Code Chapter 105.

Question 10

(10) State why the regulation is needed. Explain the compelling public interest that justifies the regulation. Describe who will benefit from the regulation. Quantify the benefits as completely as possible and approximate the number of people who will benefit.

Compelling public interest and public benefit – General

This regulation is needed to ensure that surface activities related to the development of conventional and unconventional wells are conducted in a manner that protects the health, safety, and environment and property of Pennsylvania citizens consistent with the environmental laws that provide authority for this final-form rulemaking. The surface activities requirements that currently exist in Subchapter C of Chapter 78 were last updated in 2001, prior to the significant expansion of development utilizing enhanced drilling techniques at both conventional and unconventional well sites. This final-form rulemaking is needed for several specific reasons, including: (1) codification of current policies and practices; (2) statutory changes and new environmental protection standards for conventional and unconventional wells resulting from the passage of the 2012 Oil and Gas Act including, direction to promulgate specific regulations; (3) new technologies associated with extracting oil and gas from conventional formations and gas and natural gas liquids from unconventional formations; (4) changes in the Department's other regulatory programs; (5) environmental protection gaps in the Department's existing regulatory program currently addressed through policy; and, (6) recommendations from State Review of Oil and Natural Gas Environmental Regulations (STRONGER), particularly those related to the potential risk of hydraulic fracturing communication.

Since oil and gas well drilling occurs in over 60% of the Commonwealth and oil and gas pipeline activities occur throughout the entire Commonwealth, all of its citizens will benefit from more robust and comprehensive regulations. The regulated community will benefit from this rulemaking because it streamlines authorizations and approval processes and establishes performance based requirements that will avoid or minimize environmental impacts which can be costly to remediate. Many of the environmental performance standards contained in this final-form rulemaking are either a codification of current statutory or permit requirements or are already standard industry practices. As a whole, these regulations will strengthen measures aimed at reducing the potential impacts that oil and gas activities may have on the environment.

The final-form rulemaking ensures the environment, in the interest of the public and the regulated community through the various updated provisions, including the following:

Codification of Current Policies and Practices

The Department notes that there are several areas in the final-form rulemaking where current policies and practices are codified into regulation. This should provide significant benefits for several reasons. First, by having these policies expressed in a regulation, all parties – the public, conventional and unconventional oil and gas operators, Department staff, service companies, etc. – will be able to have a transparent, up-front, black-and-white understanding of the standards of performance that apply to oil and gas development in the Commonwealth. Having these policies and practices codified into Chapters 78 and 78a will establish binding norms as regulations have the force and effect of law and provide a general presumption of reasonableness. When a policy or practice has been in effect for a significant amount of time, it may be appropriate to move to codify it into regulation. Significant examples of such subjects abound in the final-form rulemaking:

- Sections 78.17(a) and 78a.17(a), which codify the Department's interpretation of the phrase "pursued with due diligence" in section 3211(i) of the 2012 Oil and Gas Act (58 P.S. § 3211(i));
- Sections 78.51 and 78a.51, which codify the Department's interpretation of water supply replacement quality standards under section 3218(a) of the 2012 Oil and Gas Act (58 P.S. § 3218(a));
- Section 78.55, which codifies the Department's current position regarding the development and maintenance of Preparedness, Prevention and Contingency plans for well sites;

- Sections 78.56, 78a.56, 78.57 and 78a.57, which codify the Department's current policies regarding management of oil and gas waste on well sites and the interpretation of section 3273.1(a) of the 2012 Oil and Gas Act (58 P.S. § 3273.1(a));
- Sections 78.58 and 78a.58, which codify the Department's current approval process for onsite oil and gas waste processing;
- Sections 78.59c and 78a.59c, which codify the Department's position regarding the proper regulation of offsite oil and gas waste management operations;
- Sections 78.65 and 78a.65, which codify the Department's positions relating to well site restoration under section 3216 of the 2012 Oil and Gas Act (58 P.S. § 3216) and Chapter 102;
- Sections 78.66 and 78a.66, which codify the Department's interpretation of existing requirements for reporting and remediating releases;
- Sections 78.67 and 78a.67, which codify the Department's interpretation of the borrow pit exemption outlined in section 3273.1(b) of the 2012 Oil and Gas Act (58 P.S. § 3273.1(b));
- Section 78.70, which codifies the Department's current roadspreading program approval process; and,
- Sections 78.122 and 78a.122, which codify the Department's current well record and completion report requirements, in accordance with section 3222 of the 2012 Oil and Gas Act (58 P.S. § 3222).

Having these policies, practices, interpretations and procedures codified into regulations in a single location, as opposed to scattered throughout factsheets, application and approval forms and instructions, statements of policy and technical guidance documents, Department letters and webpages will provide transparency and allow all parties to understand the requirements that apply to this industry.

State Review of Oil and Natural Gas Environmental Regulations

The State Review of Oil and Natural Gas Environmental Regulations (STRONGER) reviewed Pennsylvania's oil and gas program in 2010 and 2013. Although generally complementary of the Pennsylvania program, among other suggestions the review did urge the Department 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.)." 2013 STRONGER Report, pp 51-52. It is important to note that the STRONGER recommendation on this topic did not make any distinction between hydraulically fracturing a conventional or unconventional well.

Separate Regulatory Chapters to Differentiate Between Conventional and Unconventional Requirements

The proposed rulemaking consisted of amendments to existing Chapter 78 as a single set of oil and gas regulations under Chapter 78 which applied to both conventional and unconventional operations. The final-form rulemaking separates the requirements for conventional and unconventional operations into two chapters. Chapter 78 has been narrowly tailored to meet the specific needs of the conventional industry and Chapter 78a is newly added to provide the requirements that apply to the development of unconventional wells. The addition of Chapter 78a for unconventional operations and the determination to limit existing Chapter 78 to conventional operations is needed to clearly differentiate between the requirements for conventional and unconventional operations.

The decision to create separate chapters for conventional and unconventional operations was based on comments received and recent legislation. The General Assembly enacted Act 126, an amendment to the Fiscal Code, nearly a year after the Environmental Quality Board adopted the proposed rulemaking (August 27, 2013) and roughly seven months after the Department published the proposed rulemaking for public comment in the *Pennsylvania Bulletin* (43 *Pa.B.* 7377, December 14, 2013). Under this Fiscal Code amendment, regulations promulgated under 58 Pa.C.S. (relating to oil and gas) are required to “differentiate between conventional oil and gas wells and unconventional gas wells.” For these reasons, the Department bifurcated the rulemaking into two separate chapters, one for conventional operations and the other for unconventional operations. The Department noted this significant change between proposed and draft final in its notice of availability of the Advance Notice of Final Rulemaking (ANFR) published in the *Pennsylvania Bulletin* on April 4, 2015 (45 *Pa.B.* 1615),

There are many provisions that differ between Chapter 78 and Chapter 78a. The differences between Chapter 78 and Chapter 78a reflect the differences between conventional and unconventional operations. For example, in Chapter 78 conventional operators have the continued ability to utilize pits during well drilling, completion and servicing and the ability to dispose of drill cuttings and residual waste at the well site without first needing to obtain a permit from the Department. Chapter 78a contains a number of requirements that do not apply to conventional operations including containment of regulated substances, oil and gas gathering pipelines, well development pipelines and water management plans. Please see the response to Question 27 for more information on the differences between Chapter 78 and Chapter 78a.

Electronic Filing

Electronic filing requirements throughout this final-form rulemaking are needed because when files, reports and other necessary documents are filed electronically, it enables the Department to:

- more efficiently track well development and operations from beginning to end, enabling inspectors to focus on field inspections of the hundreds of thousands of wells in the Commonwealth rather than the review and management of paper submissions;
- provide the public easy access to data via the Department’s web site;
- develop business rules to ensure that the data submitted is complete and accurate, thereby reducing the workload for both the Department and operators in returning and addressing deficient submissions;
- have a complete picture regarding well development/operations to more efficiently determine compliance. For example, when reviewing production data, Department staff needs to have permit, Well Record, Completion Report, and additional information readily available in order to determine the validity of the production/waste data. Currently, paper files need to be retrieved, sometimes from other Department offices, to obtain this information.

In the proposed rulemaking, the well permit and nearly all approvals, reports and notifications required by the rule had to be made to the Department electronically. The Department received significant public comment from conventional oil and gas operators indicating that these requirements were excessive and overly burdensome for their operations. The Department has determined that moving to all electronic filing is appropriate and necessary for the Department to fulfill its mission. Therefore, the final rulemaking retains the concept of mandatory electronic submissions to the Department.

The Department also received comments questioning the Department’s ability to implement these requirements, as they will require a substantial increase in Information Technology development and support staff than is currently required to support the Oil and Gas Program. The Department currently has a number of online electronic reporting applications for the submission of information pertaining to oil and gas wells. These applications are accessed via the Department's GreenPort enterprise portal. The Department acknowledges that the online electronic reporting functionality with respect to oil and gas operations will need to be expanded. The Department strives to develop applications that are user friendly for both external users and Department staff. The Department will continue in this effort by continually enhancing existing applications based upon user feedback. Operators will not be expected to submit information electronically if the Department has not yet developed an electronic portal to accept the information. The Department acknowledges that backup provisions will need to be in place for those situations during which the electronic portal is down.

Threatened and Endangered Species

Sections 78.15(d)-(e) and 78a.15(d)-(e) require well permit applicants to provide a detailed analysis of the impact of the well, well site and access road on threatened and endangered species. These provisions codify the existing process to ensure compliance with Federal and State law protecting threatened and endangered species.

Addressing Potential Impacts to Public Resources

The public resource impact screening process in Sections 78.15(f)-(g) and 78a.15(f)-(g) is needed because the Department has an obligation to protect public resources under Article I, Section 27 of the Pennsylvania Constitution, the Administrative Code of 1929, the 2012 Oil and Gas Act, the Clean Streams Law, the Dam Safety and Encroachments Act, the Solid Waste Management Act and other statutes. Moreover, the Department shares responsibility for the protection of natural resources with other Commonwealth agencies and municipalities that also have trustee duties under Article I, Section 27 of the Pennsylvania Constitution, as well as federal agencies. To meet these constitutional and statutory obligations, Sections 78.15 and 78a.15 establish a process for the Department to identify, consider and protect public resources from the potential impacts of a proposed well and to coordinate with applicable public resource agencies.

Public resource consideration has been a required component of the well permit application process since the Oil and Gas Act was first enacted in 1984. The provisions in this final-form rulemaking are needed to provide a clear process for identifying potentially impacted public resources, notifying applicable public resource agencies, soliciting any recommended mitigation measures and supplying the Department with sufficient information to determine whether permit conditions are necessary to avoid a potentially harmful impact to public resources.

If the limit of disturbance associated with a proposed oil or gas well site is located within a certain distance of a listed public resource as provided in Sections 78.15(f)(1) and 78a.15(f)(1), the well permit operator must provide additional information in the well permit application and notify applicable public resource agencies thirty days prior to submitting the well permit application. Under Sections 78.15(f)(2) and 78a.15(f)(2), the public resource agencies have thirty days to provide written comments to the Department and the applicant on the functions and uses of the public resource and any recommended mitigation measures. The applicant is then afforded an opportunity to provide a response to those comments. The Department then evaluates the potential impacts and assesses the need for conditions in the well permit using the criteria in Sections 78.15(g) and 78a.15(g). Section 78.15(g) and 78a.15(g) are added to this rulemaking to provide needed clarity regarding implementation of these obligations and to comply with Section 3215(e) of the 2012 Oil and Gas Act, which specifically directs the Environmental Quality Board to develop such criteria by regulation.

The right of the people of Pennsylvania to clean air, pure water, and the preservation of the natural, scenic, historic and esthetic values of the environment as expressly provided by Article I, Section 27 of the Pennsylvania Constitution are fundamental to the quality of life of the people of Pennsylvania. Additionally, public natural resources held in trust by the Commonwealth for the benefit of the people are a major economic contributor to Pennsylvania through tourism, outdoor fish and game sports, and recreation. The public resource impact screening provisions in this rulemaking provide needed clarity and clear standards for the Department to carry out its trustee obligations in administering the 2012 Oil and Gas Act program and will ensure the continued availability and benefits of these public resources throughout the Commonwealth.

Despite the Department's duties and obligations as described above, industry commentators argued that the Department does not have the statutory authority to promulgate regulations regarding public resources under Sections 78.15(f)-(g) and 78a.15(f)-(g) because the Pennsylvania Supreme Court enjoined Sections 3215(c) and (e) in *Robinson Twp. v. Commonwealth*, 83 A.3d 901 (Pa. 2013) (*Robinson Twp.*). The Department asserts that Sections 3215(c) and (e) were not enjoined or otherwise invalidated by *Robinson Twp.* and that neither the plurality nor the concurring opinions in *Robinson Twp.* read in their totality overturn the public resource protection requirements as part of the well permitting process. Additionally, as of the date of the finalization of this document, this issue is being litigated in Commonwealth Court. *See Pennsylvania Independent Oil & Gas Association v. Commonwealth* (321 M.D. 2015). The Department's Answer reflecting its interpretation of *Robinson Twp.* will be filed before Commonwealth Court by January 30, 2016."

The Pennsylvania Supreme Court's decision in *Robinson Twp.* invalidated Sections 3215(b)(4), 3215(d), 3303 and 3304 of the 2012 Oil and Gas Act as unconstitutional. As for Sections 3215(c) and 3215(e), the Court held: "Sections 3215(c) and (e) . . . are not severable ***to the extent that these provisions implement or enforce those Sections of [the 2012 Oil and Gas Act] which we have found invalid*** and in this respect, their application or enforcement is also enjoined." *Id.* at 1000 (emphasis added).

The public resource protection requirements in Sections 78.15 and 78a.15 establish a process for the Department to consider and protect public resources from the impacts of a proposed well and coordinate with public resource agencies. As such, these provisions are authorized by law and are necessary for the Commonwealth to fulfill its constitutional and statutory obligations.

The Department also received significant public comment that the public resources screen should be triggered at much greater distances from the well site than the Department proposed. The Department believes that the distances established in the final rule are appropriate. The distances to certain public resources identified in Sections 78.15(f)(1) and 78a.15(f)(1) of the final rulemaking are consistent with those used by the Department to consider public resources in well application forms since the oil and gas permitting program was established under the 1984 Oil and Gas Act. The Department has found these distances to be effective for purposes of identifying and considering potential impacts to public resources. However, given the increased size of well sites constructed when enhanced development techniques such as hydraulic fracturing are used, Sections 78.15(f)(1) and 78a.15(f)(2) require these distances to be measured from the limit of disturbance of the well site rather than from the well itself, as was the prior practice. For conventional operations this change will have little to no practical effect given the relatively small size of these conventional sites.

Sections 78.15(f)(1) and 78a.15(f)(1) of the final-form rulemaking establish a list of public resources which must be considered when a well site's limit of disturbance is located:

- 200 feet of a publicly owned park, forest, game land or wildlife area.
- In or within the corridor of a State or National scenic river.
- Within 200 feet of a National natural landmark.
- In a location that will impact other critical communities.
- Within 200 feet of a historical or archeological site listed on the Federal or State list of historic places.
- Within 200 feet of common areas on a school's property or playground.
- Within zones 1 or 2 of a wellhead protection area as part of a well head protection program approved under §109.713 (relating to wellhead protection).
- Within 1,000 feet of water well, surface water intake, reservoir or other water supply extraction point used by a water purveyor (Chapter 78a only).

Commenters argued that the Department lacked the authority to expand the list of public resources beyond those resources which are not specifically listed in Act 13.

The Department disagrees that it lacks the authority to add additional public resources given its constitutional and statutory obligations to protect public resources as discussed above. Specifically, under Section 3215(c) of the 2012 Oil and Gas Act, the Department has the obligation to consider the impacts of a proposed well on public resources "including, but not limited to" certain enumerated resources when making a determination on a well permit. Accordingly, the Department has the authority to expand the list of public resources to include public resources similar to those listed.

Sections 78.15(f)(1) and 78a.15(f)(1) of the final rulemaking include the public resources listed in 3215(c). Based on comments received, common areas of a school's property or playground and well head protection areas were added because these resources are similar in nature to the other listed public resources. Playgrounds and school common areas are frequently used by the public for recreation, similar to parks. Wellhead protection areas are associated with sources used for public drinking water supplies, another listed resource. In further response to comments, wellhead protection areas have been clarified by including a cross reference to 25 Pa. Code §109.713 and limiting the areas to those classified as zones 1 and 2. Additionally, definitions for the terms "common areas of a school's property" and "playground" have been added.

It is important to note that the provisions in §§ 78.15(f) and 78a.15(f) of this rulemaking, are not setbacks. The distances in these provisions define an area that requires coordination with public resource agencies and additional consideration during the permit review process. These provisions do not prohibit drilling activities within these defined areas.

In Section 3215(a) of the 2012 Oil and Gas Act, the General Assembly established setbacks prohibiting the drilling of oil and gas wells within certain distances from buildings and drinking water wells. For a conventional well, this distance is 200 feet; for an unconventional well, this distance is 500 feet. Additionally, unconventional wells may not be drilled within 1000 feet of a public water supply. Any changes to those provisions should be a legislative change to the 2012 Oil and Gas Act.

One item on the list that was of particular concern to many commenters is potential impacts to "other critical communities". Again, the Department has an obligation to protect public resources under Article I, Section 27 of the Pennsylvania Constitution, the Administrative Code of 1929, the 2012 Oil and Gas Act, the Clean Streams Law, the Dam Safety and Encroachments Act, the Solid Waste Management Act and other statutes. Specifically, Under Section 3215(c)(4) of the 2012 Oil and Gas Act, the Department has a legal obligation when reviewing a well permit application to consider the impacts to public resources including "other critical communities." The phrase "other critical communities" is defined in the final rulemaking to mean species of special concern identified through the Pennsylvania Natural Diversity Inventory (PNDI) consistent with the Department's past practices and policies. Under Section 3274 of the 2012 Oil and Gas Act, the Environmental Quality Board has the authority to promulgate regulations necessary to implement the statute.

The Department's well permit application materials and its "Policy for Pennsylvania Natural Diversity Inventory (PNDI) Coordination During Permit Review and Evaluation," Doc. No. 021-0200-001, establishes a process that has been and continues to be in use by well permit applicants to identify and consider species of special concern. The final rulemaking codifies this process and is consistent with the Department's long-standing use of PNDI to fulfill its responsibility to consider impacts on species of special concern when issuing permits under various environmental statutes.

In response to comments, the final-form rulemaking amends the definition of "other critical communities" to clarify that this term applies only to those species of special concern that appear on a PNDI receipt. Also in response to comments, the Department removed the provisions in the draft-final rulemaking relating to specific areas within the geographical area occupied by a threatened or endangered species and significant non-species resources. These changes were to ensure that the definition reflects the existing PNDI process.

The process for consideration of public resources in Sections 78.15 and 78a.15 makes appropriate use of information available in the PNDI database from the public resources agencies with the authority, knowledge and expertise to identify and protect species of special concern. Sections 78.15(f) and 78a.15(f) outline a reasonable and appropriate process that provides important information to the Department to evaluate potential impacts and to assess the need for additional conditions in the well permit using the criteria in Section 78.15(g) and 78a.15(g).

In addition, conventional operators expressed specific concerns that the requirement to consider impacts to other critical communities would impose an economic hardship on the conventional industry. The Department disagrees. These operators are currently required to identify the habitats of special concern species where the proposed well site or access road will be located and describe measures proposed to be taken to avoid or mitigate impacts to special concern species. The applicant must provide a PNDI receipt with the well permit application and, if a potential impact is identified, the applicant must notify the applicable public resource agency. The applicant should also be consulting with the agency to identify appropriate avoidance and/or mitigation measures. As this is an existing well permit application component necessary to comply with the statutory requirements, this final rulemaking does not impose any new financial burden.

Other commenters argued that the list should be expanded even further to included hospitals, day care centers, nursing homes and other similar facilities. The Department declined to add these facilities to the list of public resources included in §§ 78.15(f)(1) and 78a.15(f)(1). These types of facilities are not similar in nature to the other listed public resources (i.e., publicly owned parks, forests, game lands, wildlife areas, species of special concern, scenic rivers, natural landmarks, historical or archeological sites and public drinking water supplies).

In addition to the concerns over what resources must be considered, commenters also expressed concern that the requirements established under §§ 78.15 and 78a.15 will give too much power to the agencies the Department has defined as "public resources agencies" through this rule making. The Department has an obligation to protect public resources under Article I, Section 27 of the Pennsylvania Constitution, the Administrative Code of 1929, the 2012 Oil and Gas Act, the Clean Streams Law, the Dam Safety and Encroachments Act, the Solid Waste Management Act and other statutes. Specifically, the Department has a statutory obligation to consider the impacts to public resources under Section 3215(c) of the 2012 Oil and Gas Act. The General Assembly recognized the constitutional obligation to protect public resources in Section 3202 of the 2012 Oil and Gas Act, which provides that the purpose of the act is to "[p]rotect the natural resources, environmental rights and values secured by the Constitution of Pennsylvania." 58 Pa.C.S. § 3203. Under Section 3274 of the 2012 Oil and Gas Act, the Environmental Quality Board has the authority to promulgate regulations necessary to implement that statute. The Department also has the obligation to protect the Commonwealth's public resources under Article I, Section 27 of the Pennsylvania Constitution and numerous other environmental statutes that provide authority for these regulations.

Other Commonwealth agencies also have constitutional and statutory obligations over certain public natural resources. For example, the Department of Conservation and Natural Resources is required by statute to manage state parks and state forests, as well as to survey and maintain an inventory of ecological resources of the Commonwealth. Similarly, the Pennsylvania Fish and Boat Commission and the Pennsylvania Game Commission have responsibility for managing various fish and wildlife resources within the Commonwealth. Federal agencies also have jurisdiction over certain water resources, as well as federally protected fish and wildlife resources. Further, public resource agencies have particular knowledge and expertise concerning the public resources they are responsible for managing.

Sections 78.15(f) and 78a.15(f) establish a process for well applicants to notify public resource agencies and provide those public resource agencies the opportunity to submit comments to the Department on functions and uses of the applicable public resources and any mitigation measures recommended to avoid, minimize or otherwise mitigate probable harmful impacts.

By requiring the applicant and the Department to consider recommendations from public resource agencies, the final rulemaking ensures that the Department meets its constitutional and statutory obligations to consider public resources when making determinations on well permits. Importantly, these provisions function to provide the Department with information necessary to enable the Department to conduct its evaluation of the potential impacts, to review the information in the context of the criteria outlined in §§ 78.15(g) and 78a.15(g), and to determine whether permit conditions are necessary to prevent a probable harmful impact.

When proposed, the rule provided 15 days to public resource agencies to provide comment to the Department on the impacts to public resources. In response to comments, this time has been increased to 30 days. This additional time allows municipalities that only meet on a monthly basis the opportunity to respond to a request from an applicant. The additional time also provides public resource agencies a greater ability to review and provide meaningful comments and recommendations to the applicant without unduly delaying the permitting process.

Protecting Waters of the Commonwealth

Sections 78.15(b.1) and 78a.15 (b.1) establish that if the proposed limit of disturbance is within 100 feet measured horizontally from any watercourse or any high quality or exceptional value body of water or any wetland greater than one acre in size, the applicant must demonstrate that the well site location will protect those water course or bodies of water. These provisions are needed to ensure protection of waters of the Commonwealth – especially in light of the Supreme Court's decision in *Robinson Twp. V Commonwealth*, 83 A.3d 901 (Pa. 2013) enjoining the application of the setbacks in Section 3215(b) of the 2012 Oil and Gas Act. Under the Clean Streams Law, the Department has an obligation to develop regulations when it finds that an activity may create a danger to waters of the Commonwealth. These provisions are necessary to avoid such pollution. Additionally, this demonstration is currently part of the well permit application for both conventional and unconventional wells. Accordingly, these provisions seek to codify an existing practice.

The Department received significant public comment on this provision. Some commenters argued that the buffer distance was too short while others argued that the Department does not have the authority to establish a buffer of any distance. Regarding the question of authority, the Department disagrees. As discussed above, the Department has broad authority under the Clean Streams Law to establish regulations to protect waters of the Commonwealth. Regarding the buffer distance, the Department believes that 100 ft. is appropriate. Moreover, these provisions are similar to other requirements in Title 25 of the Pennsylvania Code and are consistent with the riparian buffer requirements in 25 Pa. Code Chapter 102.

As documented in the 2010 Chapter 102 final-form rulemaking "Erosion and Sediment Control and Stormwater Management", 40 *Pa.B.* 4861, there is substantial scientific support for a 100-foot buffer from streams. One such study is *Streamside Forest Buffer Width Needed to Protect Stream Water Quality, Habitat and Organisms: A Literature Review*, Bernard W. Sweeney and J. Denis Newbold, Journal of the American Water Resources Association, June 2014, which cites over 251 scientific articles and papers as sources for the paper which states that "overall, buffers ≥30 m wide [approximately 100 feet] are needed to protect the physical, chemical, and biological integrity of small streams." For these reasons, the Department determined that 100 feet was a reasonable and appropriate area for additional review to ensure protection of waters of the Commonwealth.

Antidegradation

Sections 78.15(h) and 78a.15(h) require well permit applicants proposing to drill a well that involves 1 to 5 acres of earth disturbance over the life of the project that in located in a special protection watershed to submit an erosion and sediment control plan with the well permit application. These provisions seek to codify an existing component of the well permit application and are necessary to ensure that the Department's meets its anti-degradation requirements in Chapter 93.

Notifications

Landowner notification

Section 78a.52(g) requires unconventional operators to notify landowners that if the landowner's water supply becomes impacted and the landowner has refused to allow the operator to perform a pre-drilling survey of their water supply, the presumption of liability provided by Act 13 will not apply. This provision is needed because this notice is required by Section 3218(e.1) of the 2012 Oil and Gas Act. This was a new requirement added in Act 13 of 2012.

Sections 78.61(f), 78.62(a)(5) and 78.63(a)(5) require conventional operators to provide notification to landowners after drill cuttings or other wastes are disposed on the site. This requirement is necessary to ensure that landowners are informed of where waste is disposed on their property and does not require landowner consent or prior notice.

Department notifications

In order to enhance the Department's field staff inspection efficiency, the regulation requires operators to notify the Department prior to oil and gas construction activities, such as building a well pad or installing a pit liner. These provisions allow the Department to effectively manage its resources and ensure timely inspections.

Three day notifications are required for the following;

- installation of pit liner on conventional well site. § 78.56
- prior to commencing construction of a pit of greater than 250 ft^2 for servicing, plugging or recompleting a conventional well. § 78.56(e)
- prior to disposal of cuttings on conventional well sites. §§ 78.61-78.63, 78a.61
- prior to conducting onsite processing on both conventional and unconventional well sites. §§ 78.58, 78a.58
- prior to utilizing modular above ground storage structures on both conventional and unconventional well sites. §§ 78.56, 78a.56
- after noticing deficiencies in tanks during monthly or quarterly inspections on both conventional and unconventional well sites. §§ 78.57(h), 78a.57(h)

24-hour notice for Horizontal Directional Drilling (HDD)

In § 78a.68a(c), persons conducting HDD activities associated with pipeline construction related to unconventional oil and gas operations must electronically notify the Department through its website at least 24 hours prior to beginning of any HDD activities, including conventional boring, beneath any body of water or watercourse. This provision is needed because it will allow the Department to conduct HDD inspections as the HDD is occurring.

Additionally, in § 78a.68a(j), any water supply complaints received by the responsible party for HDD shall be reported to the Department within 24 hours through the Department's web site. This requirement will ensure that the Department conducts a timely water supply investigation upon receipt of a water supply complaint to the responsible party.

Protection of Water Supplies

In the final-form rulemaking, §§ 78.51(d)(2) and 78a.51(d)(2) provide that a restored or replaced water supply will be deemed adequate if it meets the standards established under the Pennsylvania Safe Drinking Water Act (SDWA) or "is comparable to the quality of the water that existed prior to the pollution if the water quality was better than these standards." This provision is needed to clarify the Department's interpretation of the water supply replacement standard established in Section 3218(a) of the 2012 Oil and Gas Act. This water supply replacement standard was newly added to the statute as part of the 2012 Oil and Gas Act.

Many commenters argued that use of the term "exceeded" in section 3218(a) of the 2012 Oil and Gas Act should be interpreted to describe a water supply that did not meet SDWA standards instead of using the term "exceeded" to describe a water supply that had water quality better than SDWA. The impact of this interpretation would be that water supplies where water quality was documented prior to being affected by oil and gas activities as being higher quality than required by the SDWA would only require restoration to SDWA standards. Additionally, water supplies that did not meet SDWA standards prior to being impacted by oil and gas operations would only require restoration to the previous poor quality. The Department disagrees with this interpretation. The final rulemaking requires water supplies to be restored to SDWA standards or better. The SDWA standards are based on scientific fact as far as what is, and is not in a water supply to determine if it is safe for human consumption. When the water quality has been documented prior to being affected by oil and gas operations, that documented water quality, even if it is of a higher quality than SDWA standards, must be re-established by the operator. Otherwise, the Department will be allowing operators to degrade a natural resource relied upon as a water supply source. In regard to water supplies that did not meet SDWA standards prior to being impacted by oil and gas operations, the Department would be derelict in its duties if it allowed operators to provide replacement drinking water that by its own standards is not fit to drink simply because the preexisting water supply was poor. The operator may choose the size and scope of the pre-drill water supply survey to help bolster their defense of what the preexisting water quality truly was. Given the need to provide replacement water based on the positive impact determination, the additional cost borne by operators is limited to the incremental cost of providing SDWA standards water as compared to the previous poor quality, not the difference between providing no water at all and meeting the previous poor quality.

Sections 78.51(c) and 78a.51(c) provide that the presumption established in Section 3218(c) of the 2012 Oil and Gas Act does not apply to pollution resulting from well site construction. This provision is needed to clarify the Department's interpretation of the scope of the presumption in the statute. Several commenters argued that the presumption should apply to well site construction. The presumption encompasses situations in which the water supply is within 2,500 feet of the unconventional well bore, and the pollution takes place within twelve months of drilling, alteration or stimulation of an unconventional well and situations in which the water supply is within 1,000 feet of the conventional well bore, and the pollution takes place within six months of drilling or alteration of a conventional well. The Department does not have regulatory authority to expand the scope of the statutory presumption to include well pad development. If the Department finds that the pollution or diminution was caused by the well site construction, drilling, alteration or other oil and gas operations, or if it presumes the well operator is responsible for pollution as provided in 3218(c) of the 2012 Oil and Gas Act, the Department will require the operator to provide a temporary water supply to the landowner or water purveyor until the water supply is permanently restored or replaced.

Sections 78.51(a) and 78a.51(a) specify that a water supply owner may notify the Department and request an investigation if suffering pollution or diminution of a water supply. This provision is needed to clarify the scope of water supply complaints. Many commenters argued that the Department has no authority to expand water supply pollution or diminution investigations to include oil and gas operations. While § 3218(b) of Act 13 states that a landowner or water purveyor suffering pollution or diminution of a water supply as a result of the drilling, alteration or operation of an oil or gas well may so notify the Department and request that an investigation be conducted. The Department also has a responsibility to investigate all possible water supply impacts under The Clean Streams Law, including those caused by oil and gas operations. Therefore, the Department included oil and gas operations in the scope of reasons an affected landowner, water purveyor or affected person may request a water supply investigation from the Department.

Some commenters have suggested the Department specifically notify neighboring land owners and/or land management agencies if a claim of water pollution or diminution has been made to the Department. The Department declined to make this suggested change because the Department administers a robust program to prevent and respond to complaints and spills and releases associated with oil and gas activities. When the Department concludes that a water supply may be impacted by a spill, the Department routinely provides notice to those persons potentially impacted and gathers additional information to aid further investigation if warranted. The investigation may include sampling water supplies that are potentially impacted by a spill (if permission is obtained from the water supply owner) based on the circumstances of the spill, including the physical and hydro geologic environment and the type and size of the spill. Each investigation related to a spill varies depending on the circumstances involved. For that reason, the Department determined that the suggested change was not appropriate to be added to the rulemaking at this time.

Many commenters argued that the Department should reduce the 10-day time frame afforded to it in § 3218(b) of Act 13 to investigate a water supply since impacts to water supplies are both spatial and temporal. While the Department cannot change the statutory language, it is committed to investigate all claims of water supply pollution or diminution in a timely manner. This commitment can be found in the document titled "Standards and Guidelines for Identifying, Tracking, and Resolving Oil and Gas Violations" (Document number 820-4000-001 Revised January 17, 2015).

Predrilling or Prealteration Survey

The Department received significant public comment that the rule should include a specific list of potential contaminants that must be analyzed for in each pre-drilling or pre-alteration survey. Section 3218(c) of the 2012 Oil and Gas Act establishes a presumption of liability for an operator who impacts a water supply located within a certain distance from the wellbore and within a certain timeframe. Subsection (d) allows an operator to rebut the presumption by proving that "the pollution existed prior to the drilling, stimulation or alteration activity as determined by a predrilling or prealteration survey…"

The Department believes that the General Assembly chose to place the onus of not conducting a predrill survey on the backs of operators, who might not be able to rebut a presumption of liability if a water supply is not sampled prior to drilling or a particular substance is not tested for by the operator. By failing to establish predrill water quality, the operator opens itself up to liability for any failure to meet drinking water standards in any water supply located within the presumption's radius for any substance found in the water supply. Therefore, presumption is more protective of water supplies than a prescribed list of contaminates to be sampled for with a predrill water sample. The Department will require water supplies impacted by oil and gas operations to be restored to SDWA standards or better, based upon the pre-drill water supply survey results.

The final rule allows an operator to submit a copy of all predrill sample results taken as part of a survey to the Department by electronic means. Prior to this rule, operators were required to submit each individual's sample by mail as it was completed, which was much less efficient for both operators and the Department due to the comprehensive nature of the analysis and the way analyses are completed. The Department received significant public comment regarding the time frames under which this information was required to be submitted. The final rule allows all sample results pertaining to the well of concern to be submitted to the Department by the operator 10 days prior to commencement of drilling the well in a single coordinated report. The Department believes that this change allows this portion of the regulation to strike an appropriate balance between being reasonable and protective of public health and safety and the environment. The Department does not believe that it is appropriate to accept sample results as predrill samples after oil and gas activity has begun.

Area of Review

Pre-Hydraulic Fracturing Surveys

The Department estimates that there are approximately 300,000 abandoned wells across Pennsylvania. A serious risk to waters of the Commonwealth is posed when an operator inadvertently alters an abandoned well by inducing hydraulic or pressure communication during the hydraulic fracturing process. Altering an abandoned well by subjecting it to pressures and reservoir sections it was not necessarily built to isolate can and has led to a number of issues, including methane migration and water supply impacts. Even in instances when no water supplies are affected, communication with any adjacent oil or gas well has the potential to lead to well control incidents that may pose serious safety hazards.

Sections 78.52a and 78a.52a of the final rulemaking require operators to identify abandoned, orphan, active and inactive wells within 1,000 feet of the vertical and horizontal wellbore prior to hydraulic fracturing. The review distance is set at 500 feet for vertical oil wells in § 78.52a. The identification process requires operators to review the Department's orphan and abandoned well database, review farm line maps, and submit a questionnaire to landowners whose property lies within the prescribed area of review prior to drilling in cases where hydraulic fracturing activities are anticipated at the well site. Other available databases and historical sources must also be consulted.

Sections 78.73 and 78a.73 indicate which subset of the identified wells must be monitored based on vertical proximity to the stimulated interval. Wells that penetrate within defined vertical separation distances have the potential to serve as preferential pathways allowing pollution of the waters of the Commonwealth.

Monitoring protocols will be based on the level of risk posed by individual well sites within the area of review and represent a mechanism for minimizing or altogether eliminating the potential for any lasting environmental impacts or other safety hazards.

The area of review regulation also accounts for scenarios where access to well sites may be limited or previously unidentified geologic features may affect hydraulic fracturing activities through the introduction of provisions that require operators to monitor treatment pressures and volumes during stimulation activities. Such monitoring allows practical operational flexibility with regard to the mechanisms available for the identification of fracture propagation possibly representative of a communication event.

When communication incidents are not observed immediately, the extent of the environmental impacts may be more severe. Remediation activities such as stream diversions, installation and maintenance of treatment systems and repairs to affected wells or plugging activities are costly and may require operators to finance projects over the course of several years. For example, work over reports submitted to the Department in association with an ongoing stray gas migration case in northeastern Pennsylvania document well repairs amounting to tens of thousands of dollars per day. Depending on when a communication is noted, future wells may be drilled that are not considerate of open communication pathways. Such wells may have to be abandoned prematurely or certain fracture stages may have to remain unstimulated, thus reducing the economic value of the new well and the efficiency of resource recovery. The final rulemaking strikes a reasonable balance between the costs of conducting the area of review survey and monitoring offset wells and the benefit associated with avoiding communication incidents. This benefit will be realized by operators and the citizens of the Commonwealth.

To further elaborate on one notable consequence of communication incidents, it is important to note that hundreds of documented stray gas migration investigations have taken place during the modern era of oil and gas development in Pennsylvania, i.e., between 1984 and the present day. Prior to passage of the 1984 Oil and Gas Act, it is difficult to speculate at what frequency such incidents occurred. A subset of these incidents has been directly attributed to communications with abandoned wells during hydraulic fracturing. In association with a certain number of the total recorded stray gas migration incidents in the state, water supplies have been impacted for periods extending over several years. In some cases, property damage has resulted and lives have been lost due to the characteristics of methane gas under certain conditions.

The final area of review regulation, which requires operators to document due diligence in a consistent manner and report unanticipated communication incidents that occur in a systematic way, will have far-reaching benefits and minimal costs. Addressing this particular issue has been supported by STRONGER, and comports with the Act, which intends that oil and gas wells be constructed in such a way to prevent gas and other fluids from entering sources of fresh groundwater.

Control and Disposal Planning (PPC Plans)

In §§ 78.55 and 78a.55 of the final-form rulemaking all well operators are required to develop and implement a site specific PPC Plan for oil and gas operations. This requirement is needed to clarify requirements in §§ 91.34 and 102.5(l). Additionally, site-specific PPC plans are needed to address site-specific conditions, including local emergency contact information.

There may be instances where the operator finds that a PPC plan prepared for one well site is applicable to another site. Each individual plan must be analyzed prior to making such a determination. It is not the intent of this rulemaking to require each PPC plan be separately developed and different for each well site. The Department understands that many of the practices covered in the PPC plan are the same for a given operator. It is also not the intent of this rulemaking to require that all PPC plans be revised annually. In many cases, if conditions at the site do not change, there will be no need to make revisions to the PPC plan.

The Department received significant public comment from conventional oil and gas operators indicating that this requirement was excessive and overly burdensome for their operations. The commenters argued that the requirement to develop and update site specific PPC plans was unnecessary because conventional well sites are all so similar that a single plan is sufficient to address all sites. The commenters also argued that maintaining a copy of the PPC plan on the site is overly burdensome and unnecessary for conventional operators. Commenters also expressed concerns about §§ 78.55(a) and 78a.55(a) which simply reiterate the requirements already existing in Chapters 91.34 and 102.5(l). Since §§ 78.55(a) and 78a.55(a) do not establish any new requirements, this subsection does not present any new burden on operators. Operators may develop a single integrated PPC plan to satisfy the requirements of subsection 78.55(a) and 78.55(b). PPC Plans satisfying the requirements of §91.34 alone may not also satisfy the requirements of §102.5(l). PPC plans are required for production and storage of pollutants as well as for pipelines and processing. The final rulemaking does not exempt the requirements of either §91.34 or §102.5(l) for conventional or unconventional oil and gas activities. The purpose of §§ 78.55 and 78a.55 is largely to cross-reference existing requirements in other regulatory chapters implemented by the Department.

For these reasons, the Department has retained the requirement to develop and implement site specific PPC plans in the final rule.

It appears that the commenters incorrectly assumed that every single site where an impoundment, production, processing, transportation, storage, use, application or disposal of pollutants occur must have the PPC Plan posted on site at all times. This rulemaking does not require persons to post PPC plans at these sites at all times. This rulemaking does not require a PPC plan for the impoundment, production, processing, transportation, storage, use, application or disposal of pollutants to be maintained on the site.

Instead, §§ 78.55(e) and 78a.55(e) require well operators to maintain a copy of the PPC plan at the well site during drilling and completion activities only. This requirement is needed because the site is active during drilling and completion activities and there is an increased risk of a spill, release or other incident. In the event such an incident, the purpose of the onsite PPC plan is to minimize any impact. The Department recommends well operators to maintain the PPC plan on the site when it is active, including during alteration and plugging activities.

Sections 78.55(e) and 78a.55(e) also require well operators to provide the PPC plan to the Department, the Fish and Boat Commission or the landowner upon request. The requirement to provide the PPC Plan to the Fish and Boat Commission upon request is needed because the Fish and Boat Commission has jurisdictional responsibilities over waters of the Commonwealth. The PPC Plan enables the Fish and Board Commission to investigate areas of concern that fall under their jurisdiction. The Department has determined that this is reasonable and appropriate to ensure compliance with all applicable law. Additionally, the requirement to provide landowner a copy of the PPC plan upon request in needed because landowners have a vested interested in the contents of the PPC plan and should have access to the plan. Therefore, it is in the best interest of the landowner to be provided a copy of the PPC Plan so they understand the activities and potential pollutants and how they will be controlled in the event of a pollution release.

Temporary Storage

Sections 78.56 and 78a.56 regulate temporary storage of regulated substances used or produced at the well site during drilling, altering, completing, recompleting, servicing and plugging the well. The purpose of these provisions is to ensure that temporary storage at the well site during these activities protects public health, safety and the environment. These provisions are needed to minimize spills and releases into the environment.

Section 78a.56 of the final-form rulemaking bans the use of pits for temporary waste storage at unconventional well sites. The Department has determined that it is appropriate to remove this practice because the typical size and length of use by unconventional operators is generally incompatible with technical standards for temporary pits prescribed under § 78.56. Accordingly, in § 78.56, the Department has retained the use of temporary pits for conventional operators because the typical size and length of use by conventional operators is generally compatible with the appropriate technical standards outlined in this section. The Department has allowed the disposal of residual wastes including contaminated drill cuttings in a pit at conventional well sites for decades. When done in accordance with appropriate environmental standards, such disposal can occur without significant harm to public health and safety or the environment. Therefore, the Department has updated the standards for pits in §§ 78.56 and 78.62 and the final-form rulemaking retains pits as an option for proper temporary waste storage at conventional well sites.

In addition, in the proposed rulemaking, the Department included a requirement that temporary pits must have an inside slope 2:1(horizontal: vertical) or flatter. The Department received significant public comment on this proposed requirement and ultimately removed the minimum slope requirement from the final-form rulemaking. Instead, the final-form rulemaking continues to allow conventional operators to construct pits with steep inside slopes provided that the pits have an aerial extent of less than 3,000 ft^2 and volumetric capacity of less than 125,000 gallons. For larger pits, the rule requires the operator to obtain a site specific approval from the Department prior to constructing the pit. This requirement is necessary because the definition of conventional formation is very broad and technological advances may result in conventional operators utilizing large pits that are in place for a long period of time, similar to the type and scope of use of pits by unconventional operators and the Department has determined that this type of pit use is generally incompatible with the technical standards for temporary pits prescribed under § 78.56. This revision will allow continued use of conventional pits at well sites, prevent an unnecessary increase in the footprint of pits and provide appropriate protections to the environment when operators require the use of large pits.

The final rule requires that pit liners for temporary storage have a thickness of at least 30 mils and allows for the liner manufacturer to demonstrate that a thinner liner is equally protective. Commenters indicated that a requirement to use a 30 mil liner was unnecessary and overly burdensome. Commenters argued that irrespective of cost, a 30 mil liner is 184 pounds heavier than a 20 mil liner. The Department acknowledges that 30 mil liners are heavier per unit area than 20 mil liners. Based on the best information available to the Department and assuming use of vertical walls and a high density polyethylene (HDPE) liner, a pit liner where the difference in weight between a 20mil thickness and a 30 mil thickness is 184 lbs. has an aerial extent of approximately 3,800 ft^2 with the 20 mil liner weight being approximately 368 lbs. and the 30 mil liner weight being approximately 552 lbs. The weight of a 20 mil pit liner of this size is substantial enough to require machinery and/or a multi-person crew to install. A pit of this size has been represented to the Department by the members of the Conventional Oil and Gas Advisory Committee (COGAC) as the largest pit used during conventional operations in Pennsylvania. In addition, the example provided by COGAC included vertical walls that are 8 feet tall which would make installation of even a 20 mil liner very difficult without machinery or a multi-person crew. Also, conventional operators have indicated to the Department that the pits used in conventional well operations are typically no larger than 10 feet by 30 feet and hold less than 4,200 gallons. The liner required for a pit of that size is conservatively 650 ft^2 with the 20 mil liner weight being approximately 62 lbs. and the 30 mil liner weight being approximately 95 lbs. which is a weight difference of only 33 lbs. The Department believes that the example given by commenters is an extreme example and consequently, the Department does not believe that the example of a 184 lb. weight difference is an accurate representation of the impact of a 30 mil liner requirement on the conventional oil and gas industry. The Department does not believe that an increase in weight of 33 lbs. for a typical pit or 184 lbs. for a very large pit is overly burdensome for conventional operators to manage.

Prior to this revision, § 78.56 did not include any specification for minimum liner thickness and only included a requirement for a "synthetic impermeable liner." However, § 78.62 (relating to disposal of residual wastes in a pit) has required the use of a 30 mil liner or an alternate material if approved by the Department since Chapter 78 was initially promulgated in 1989. The Department acknowledges that when disposing of cuttings by land application, a liner thickness is not specified, but the Department notes that disposal of cuttings in a pit is far more common than land application. The Department has approved a small but significant number of liner products with a 20 mil thickness since Chapter 78 was initially promulgated but does not believe that the exception should define the rule. Due to these requirements, the Department believes that conventional oil and gas operators should already be using 30 mil liners or an approved alternative most of the time. The Department has observed many operators utilizing liner materials thinner than 20 mils, which met the requirement of being a "synthetic impermeable liner" but were not robust enough to remain impermeable during typical use as a pit liner. The final rule eliminates use of liner materials that are known to not be robust enough to provide adequate environmental protection and provides certainty for operators when selecting a pit liner material.

Chapter 78 currently includes the requirement for the bottom of a temporary pit to remain at least 20 inches above the seasonal high groundwater table. This requirement has been in place since Chapter 78 was initially promulgated in 1989. In the final rule, under § 78.62, operators are required to determine that the pit meets this requirement prior to using the pit. The determination must be made by a soil scientist or other similarly trained person using accepted and documented scientific methods. The Department believes that this requirement is necessary and appropriate to ensure compliance with the long-standing requirement to maintain 20 inches of separation between the bottom of the pit and the seasonal high groundwater table.

The Department received considerable public comment on this proposed requirement from conventional operators indicating that it should be removed because it is expensive and unnecessary however this requirement is retained in the final rule. The Department notes that the rule does not exclusively require this determination to be made by a soil scientist, but instead it allows the determination to be made by a soil scientist or other similarly trained person. The Department believes that training can be provided to conventional oil and gas operators to ensure they have the skills necessary to accurately identify the seasonal high groundwater table and comply with this requirement without having to hire a professional soil scientist in all cases. In addition, the Department notes that since 1989, in order to ensure that they were in compliance with this requirement; conventional operators must have been conducting an evaluation of the soils beneath the bottom of their pit locations. Therefore, the Department believes that the effect of this new requirement will be to ensure that conventional operators document their determinations that their pits meet this long standing regulatory requirement prior to using them. Making this requirement even more important is the fact that once the liner is placed into the pit and the pit is put into service, it is very difficult for the Department to make a determination in the field regarding compliance with this requirement. The Department does not believe that this new requirement presents any significant new burden on conventional operators.

The Department also received comments regarding the need to test the seams of pit used under § 78.56. The Department believes that visual inspections are not an acceptable means to ensure the liner integrity requirement is met. Seam testing should be conducted in accordance with a quality assurance and quality control plan and operators should consult with the manufacturer of the liner to determine appropriate testing protocols. The Department believes that testing of liner seams is an appropriate practice to ensure the quality of the liner installation and the rulemaking is appropriate to protect waters of the Commonwealth from pollution due regulated substances leaking from pits.

Many oil and gas operators have moved to using modular aboveground storage structures to store water and wastewater on well sites. These structures come in many shapes, sizes and designs. The permit by rule structure contemplated by §§ 78.56 and 78a.56 for temporary storage on the well site does not provide adequate protection to public health and safety or the environment due to the variability of the designs of these structures. Sections 78.56 and 78a.56 codify current requirements of Department review and approval of modular aboveground storage structures prior to their use to store regulated substances on a well site. In addition, §§ 78.56 and 78a.56 will result in more efficient implementation of current requirements by including a requirement for the Department to publish approved structures on its website. This requirement will eliminate the need for the Department to conduct multiple evaluations of the same design and allow for a single statewide approval. It is important to note that the statewide approval will be applicable to the design of the structure only. Subsections 78.56(a)(3) and 78a.56(a)(3) require the operator to obtain siting approval from the Department for site specific installation of all modular aboveground storage structures for each individual well site where use of the modular aboveground storage structure is proposed. The Department evaluates proposed modular aboveground storage structures on a case by case basis to determine whether the proposed structure will provide equivalent or superior protection. The Department reviews not only modular designs but also site specific construction and topographic conditions. The Department’s website will list approved modular structures but authorization of the process will still be required to ensure proper siting of the facility. This provision was originally proposed to include all modular aboveground storage structures but in response to comments, the Department has amended the requirement to apply to only those structures which exceed 20,000 gallons of total capacity.

In the proposed rulemaking, § 78.56(a)(5)-(7) addressed security requirements for pits, tanks and approved storage structures and required operators to equip all tank valves and access lids to regulated substances with reasonable measures to prevent unauthorized access by third parties such as locks, open end plugs, removable handles, retractable ladders or other measures that prevent access by third parties. In addition, for unconventional well sites, a fence was required to completely surround all pits to prevent unauthorized acts of third parties and damage caused by wildlife unless an individual was continuously present at the well site. Finally, operators of unconventional well sites were required to display a sign on or near the tank or other approved storage structure identifying the contents and an appropriate warning of the contents such as flammable, corrosive or a similar warning. The Department received significant public comment from conventional operators indicating that the costs associated with equipping pits, tanks and approved storage structures with the prescribed security measures would be exorbitant for the conventional industry which currently employs approximately 175,000 tanks. The Department removed the requirement to install equipment to prevent unauthorized access by third parties for conventional operations but has retained this requirement for unconventional operators in § 78a.56. The Department also received significant public comment from unconventional operators that the requirements to install fences around all pits or provide continuous presence on unconventional well sites was inappropriate and would not be effective. As noted above Department has revised § 78a.56 to disallow the use of pits on unconventional well sites and accordingly has removed the requirement to install fencing around pits on unconventional well sites. The Department has also retained the requirement to maintain signs on tanks or other approved storage structures to prevent confusion when multiple storage structures are located in close proximity on a well site.

Control, Storage and Disposal of Production Fluids

Sections 78.57 and 78a.57 in the final-form rulemaking contain requirements that apply to permanent storage of production fluids. The purpose of these provisions is to ensure that storage during the production of well, when there is less activity occurring at the well site, is protective of public health, safety and the environment. These provisions are needed to minimize spills and releases to the environment.

In the proposed rulemaking, § 78.57(e) banned further use of underground storage tanks and required both conventional and unconventional operators to remove all underground storage tanks within 3 years of the effective date of the final rule. The Department received significant public comment on this provision from both conventional and unconventional operators arguing that it was inappropriate, overly burdensome and exorbitantly expensive. Conventional operators argued that with an estimated 150,000 buried tanks the cost to remove each tank and the cost to replace tanks that will be damaged in the removal process was significantly greater than the Department had considered when drafting the rule. In addition, operators indicated that the act of burying tanks is done to provide freezing protection for produced waters in the winter and to allow water and oil to be more easily separated. As a result of public comment, the Department has amended the final-form rulemaking in §§ 78.57(e) and 78a.57(e) to allow the use of buried tanks by both conventional and unconventional well site operators and does not require removal of existing buried tanks. Underground storage tanks warrant extra scrutiny because they are not as easily inspected and can provide a more direct conduit for contamination into groundwater and therefore have included provisions in the final rule to require the location of all existing and any new underground storage tanks at well sites to be reported to the Department.

Sections 78.57(f) and 78a.57(f) implement Section 3218.4(b) of the 2012 Oil and Gas Act which requires that permanent aboveground and underground tanks comply with the applicable corrosion control requirements in the Department's storage tank regulations. Some commenters argued that these provisions shouldn’t apply because storage tanks on well sites are not permanent. In the context of tanks regulated under §§ 78.56 and 78a.56, the Department agrees because those tanks are used only during drilling and completion of the well and are subject to the well site restoration timeframes. However, in the context of tanks regulated under §§ 78.57 and 78a.57 for production fluids, the Department disagrees. These tanks are in place on the well site for the duration of the productive life of the well which can be decades or in some cases, centuries. If tanks that are in service for this duration are not considered permanent, then no tank would ever be considered permanent under this interpretation. Accordingly, the tanks regulated by §§ 78.57 and 78a.57 are permanent and subject to the corrosion control requirements in Section 3218.4(b) of the 2012 Oil and Gas Act.

Commenters also argued that because the Storage Tank and Spill Prevention Act (Tank Act) specifically exempts underground and aboveground storage tanks located at oil and gas well sites from regulation, there are no applicable corrosion control requirements in the Department's storage tank regulations. Therefore, regulations specifying that operators must comply with corrosion control requirements in §§ 245.531 – 245.534 (relating to corrosion and deterioration prevention) are inappropriate and not authorized by section 3218.4(b) of the 2012 Oil and Gas Act. The Department disagrees with this interpretation. Section 3218.4(b) of the 2012 Oil and Gas Act expressly requires permanent aboveground tanks to comply with the applicable corrosion control requirements in the Department's storage tank regulations. Additionally, Section 3218.4(b) was enacted after the Tank Act.

The Department notes that the final rule does not require retroactive application of the corrosion control requirements. Only new, refurbished or replaced aboveground and underground storage tanks must comply with the applicable corrosion control requirements. In addition, the Department has also explicitly removed the requirement to use Department certified inspectors to conduct inspections of interior linings or coatings which will alleviate some burden on oil and gas operators. Finally, the Department notes that operators may choose to use non-metallic tanks which can often be less expensive than steel equivalent and do not require any additional cost to ensure protection from corrosion.

Sections 78.57(i) and 78a.57(i) require operators to conduct periodic inspections of tanks used to control and store production fluids on a well site and document each inspection. The Department initially proposed that all inspections should be conducted monthly, which is the same frequency as required by the Department's storage tank regulations but has revised the requirement to be monthly for unconventional operators and quarterly for conventional operators. The periodic maintenance inspection is intended to be a visual check of the tank and containment area to ensure that the tank and containment structures are in good working condition and that ancillary and safety equipment are in place and in good working condition. This provision is necessary to minimize the potential for impacts to waters of the Commonwealth. Requirements to conduct periodic inspection of production tanks are appropriate to ensure that the tanks are designed, constructed and maintained to be structurally sound with sound engineering practices adhering to nationally recognized industry standards and the manufacturer's specifications. The Department received significant public comment from conventional operators that this requirement is unnecessary and overly burdensome for conventional operations for a variety of reasons.

First, commenters suggested that periodic inspections are not needed because according to the Department's compliance data, there were only 8 instances of leaking tanks in use by conventional well operators between 2008 and 2014.The commenters asserted that this suggests that only 0.000045% of all tanks used by conventional operators have ever been documented to leak. It is not clear to the Department which inspections are included in that count but the Department's review of inspection data for 2014 alone reveals more than a dozen incidents where quarterly inspections may have mitigated a tank storage release. In addition, the Department notes that since storage tanks are not subject to many inspections, the number of leaks found by the Department expressed as a fraction of the total number of inspections is not a reliable measure of the frequency of storage tank releases. Finally, the Department inspected only slightly more than

6% of the conventional wells in 2014, so it is presumable that there were storage tank releases that are unknown to the Department, which is a problem that could be mitigated by well operators conducting periodic inspections.

Second, commenters suggested that requiring conventional operators to comply with requirements similar to those placed on unconventional operators is inappropriate because the storage tanks used at conventional well sites are significantly different than those used at unconventional well sites. The Department does not believe that the production tanks used by conventional operators are significantly different than those used by unconventional operators. While the tanks used by unconventional operators may be larger in some cases, tanks used by the conventional well industry can be large enough to cause a significant spill, and the differences between the substances stored in the conventional well industry compared to unconventional is arguably not as great is represented by the conventional well operators.

Third, commenters suggested that the difference in water quality between conventional and unconventional wells is significantly different. Commenters presented chemical analysis of conventional and unconventional produced water to demonstrate the chemical differences. The USGS provides an alternative source of data on the following webpage:

http://energy.usgs.gov/EnvironmentalAspects/EnvironmentalAspectsofEnergyProductionandUse/ProducedWaters.aspx#3822349-data

Below is a link to download the Complete List of Provisional National Produced Waters Geochemical Database Materials:

http://energy.usgs.gov/Portals/0/Rooms/produced_waters/tabular/USGSPWDB_v2.1.xlsx

The following data show a comparison between the data provided by the Pennsylvania Independent Petroleum Producers (PIPP) and appropriate data extracted from the USGS spreadsheet:

					ratio of unconventional over conventional	
Substance	Shallow - PIPP	Conventional - USGS	Marcellus - PIPP	Unconventional - USGS	PIPP	USGS
Barium	48.4	397	6500	1149	134.3	2.9
Calcium	6179	14075	18000	7410	2.9	0.5
Iron	53	114	60	39	1.1	0.3
Lithium	2.2	6.1	150	60	68.2	9.8
Manganese	4.2	13.4	5	3.5	1.2	0.3
Potassium	90	894		435		1.8
Sodium	19879	27327	48000	35459	2.4	1.3
Strontium	110	994	4000	1489	36.4	1.5
Bromine	628	752		1081		1.4
Chlorides	42954	87562	116900	50085	2.7	0.6
TDS	80106	140236	195000	85293	2.4	0.6
				average ratio:	28.0	1.8

In the preceding table, the two columns to the right compare the ratios of contaminants in produced fluid from deep wells over shallow wells. For example, PIPP asserts the barium in produced fluid from Marcellus wells is 134.3 times greater than from shallow wells. According to the USGS data, that ratio is 6 instead. Overall, data presented by PIPP suggests the contaminants in produced fluid from Marcellus wells average 28 times greater in concentration compared to shallow wells, whereas the USGS data show the average contaminant concentration from unconventional wells is only 1.8 times greater than from conventional wells. For calcium, iron, manganese, chlorides, and TDS, the data provided by PIPP indicates greater concentrations from unconventional wells, whereas the data from USGS shows greater concentrations from conventional wells. Although the data source selected by PIPP claims the concentration of contaminants in produced fluid from unconventional wells is greater than from conventional wells for every substance listed, the USGS data show a near even split with five substances out of eleven in greater concentration from conventional wells compared to unconventional wells. Based on this information, the Department has determined that the differences in contaminant concentrations between conventional and unconventional produced fluids do not warrant lax regulatory standards for control, storage and disposal of production water from conventional wells.

The Department continues to believe that periodic inspections are appropriate common sense accident prevention safeguards that every storage tank operator should follow. In response to comments, the Department has amended subsection 78.57(h) to reduce the frequency of inspection from once per calendar month to once per calendar quarter to allow coordination between tank inspections and mechanical integrity assessments required under § 78.88 which requires wells to be inspected on a quarterly basis. This change will have the effect of reducing the burden on conventional operators while ensuring that storage tanks for produced fluids on well sites are inspected periodically.

Secondary containment

Section 78.57(c) and 78a.57(c) of the final-form rulemaking requires secondary containment for aboveground tanks that contain brine and other fluids produced during operation of the well. Since well sites in the production phase are not inspected by the Department with the same frequency as those in the well development, restoration and plugging phases, and do not have continuous operator presence, the Department feels it is necessary to require secondary containment for aboveground tanks used to store brine and other fluids produced during operation of the well to prevent undetected releases into the environment.

Some commenters stated that it is contradictory for the Department to allow the spreading of brine on roads in § 78.70 yet require secondary containment around aboveground tanks containing brine. The Department requires brine road-spreading plans be submitted on an annual basis that are reviewed and approved by the Department. Also, monthly reports must be submitted listing the locations, frequency and amount of brine spread during the previous month. Provisions in § 78.70 also include environmental controls consisting of maximum application rates, chemical analysis, distance restrictions from surface water, 24-hour notice and source information. Releases of brine from above ground tanks used for production fluids are uncontrolled and usually undetected as they occur. Secondary containment around aboveground tanks will prevent these releases from entering the environment until they are detected.

The Department does not require secondary containment to be installed until a tank or one tank in a series of tanks is added, refurbished or replaced. The concern of a larger footprint created by secondary containment where available area may be an issue is addressed by allowing the use of double walled tanks capable of detecting a leak in the primary containment to fulfill the requirements in this subsection.

Onsite processing

Sections 78.58 and 78a.58 codify existing practices to allow onsite waste processing to occur provided all of the waste processed on the site is either generated at the site or will be beneficially reused at the site after approval is obtained from the Department. The purpose of this provision is to encourage recycling and reuse in hydraulic fracturing operations and codify these existing practices. These provisions are needed to ensure that processing activities are conducted in a way that protects public health, safety and the environment. Additionally, the purpose of these provisions is to minimize spills and releases to the environment.

The final rule also seeks to streamline this process by including a requirement for the Department to publish approved structures on its website. This requirement will eliminate the need for the Department to conduct multiple evaluations of the same process and allows for a single statewide approval. Once a process receives approval, operators wishing to utilize that process would be required only to register use and provide notification to the Department 3 days prior to initiating processing. These sections also include exemptions from the requirement to obtain approval and register with the Department prior to conducting the following processes: blending wastewater with fresh water, aeration and filtering solids from fluids. The Department does not believe that specific Department oversight is necessary for these processes.

The Department received significant public comment on this section indicating that allowing operators to conduct waste processing on well sites is not appropriate and not protective of public health and safety or the environment. The Department disagrees and believes that it is appropriate to allow waste processing on a well site to facilitate beneficial reuse of waste and efficient operations in the limited manner outlined in these provisions.

The Department received comments that requiring an operator to wait for solid waste remaining after the processing or handling of fluids under §§ 78.58 and 78a.58 be characterized under § 287.54 (relating to chemical analysis of waste) before the solid waste leaves the well site requires too much time (27 days) to store it onsite until the sample analysis is received. The Department requires that a waste characterization be conducted in accordance with § 287.54. The Department believes that this is an appropriate cross-reference, as the subsection only concerns those wastes that will be leaving the well site where they were generated. Once the waste leaves the well site, the exemptions under Section 3273.1 of the 2012 Oil and Gas Act no longer apply and the Waste Management program regulations govern testing and handling of the waste.

Commenters also noted that waste processing often generates high concentrations of Technologically Enhanced Naturally Occurring Radioactive Material (TENORM). Please refer to the section below related to TENORM and the radiation protection action plan provisions in §§ 78.58(d) and 78a.58(d).

Other commenters indicated that the rule is overly burdensome and does not go far enough to support processing, recycling and beneficial reuse of fluids and other waste materials at well sites. It is the intent of the rule to support waste processing on a well site to facilitate beneficial reuse of waste and efficient operations; however, certain activities present a greater level of environmental hazard that the Department should have the opportunity to review and approve those activities prior to implementation.

Radiation Protection Action Plan (§§ 78.58(d) and 78a.58 (d))

The Department's 2015 TENORM Study Report presented several observations and recommendations regarding radioactive material associated with the oil and gas industry. While the study outlines recommendations for further study, it concluded there is little potential for harm to workers or the public from radiation exposure due to oil and gas development.

The Department remains committed to protecting the public from unnecessary exposure to radiation and is actively pursuing the recommendations of the 2015 TENORM study report.

The 2015 TENORM Study report observed that there is the potential to produce loads of TENORM waste with radium-226/-228 concentrations greater than 270 pCi/g, which is the threshold for federal DOT regulations regarding the labelling, shipping and transport of Class 7 hazmat radioactive material.

In response to comments and the 2015 TENORM Study report, the Department has added §§ 78.58(d) and 78a.58(d) to this final-form rulemaking requiring an operator processing oil and gas fluids onsite to develop a radiation protection action plan which specifies procedures for monitoring and responding to radioactive material or TENORM produced by the treatment process. These sections also require procedures for training, notification, recordkeeping, and reporting to be implemented. These sections are needed to ensure that workers, members of the public, and the environment are adequately protected from radioactive material that may be found in fluids processed on the well site.

Impoundments

Standards and registration for well development impoundments

Sections 78.59a, 78.59b, 78a.59a and 78.59b of the final-form rulemaking establish construction standards for well development impoundments. Currently, oil and gas operators use impoundments to store freshwater and other fluids approved by the Department for use in drilling and hydraulic fracturing activities that do not trigger the permitting requirements in § 105.3(a)(2)-(3) and are unregulated by the Department. The provisions in these sections seek to outline the necessary requirements to ensure that those facilities that do not meet the Chapter 105 permitting requirements have structural integrity and do not pose a threat to waters of the Commonwealth. This is necessary because the scope and type of use of well development impoundments by the oil and gas industry is significantly different than the scope and type of use by other industries. The Department has observed the use of these impoundments to hold up to sixteen million gallons of freshwater and other approved fluids varying in quality that are usually not indigenous to the local watershed where these facilities are constructed. For this reason, the escape of that water may pose a threat of pollution to waters of the Commonwealth.

The Department's structural standards and measures in §§ 78.59a, 78.59b, 78a.59a and 78.59b are intended to prevent leaking of well development impoundments in the groundwater and surrounding surface waters. Failure to construct well development impoundments in a structurally sound manor would allow for the potential for a catastrophic failure of the impoundment that may cause serious harm to public health and to the environment.

Sections 78.59b(d) and (f) and 78a.59b(d) and (f) specify that an impervious liner must be used and the bottom of the well development impoundments must be placed be at least 20 inches above the seasonal high groundwater table to prevent groundwater infiltration. The Department received comments stating that well development impoundments should be required to follow 25 Pa. Code Chapter 105. The Department disagreed because these regulations only pertain to dams that are not regulated under Chapter 105 because they do not meet the height and volume thresholds. The Department received comments saying that the regulations for well development impoundments unfairly target the oil and gas industry. The Department disagrees and believes that adherence to § 78.59a provides for the structural integrity of the impoundment to provide adequate public safety and that § 78.59b provides reasonable assurances that the water placed in the impoundments does not pose an environmental hazard. Failure to construct well development impoundments in a structurally sound manor would allow for the potential for a catastrophic failure of the impoundment that may cause serious harm to public health and to the environment.

The final-form rulemaking also establishes registration of existing and future well development impoundments with the Department electronically through its website. This is needed to allow the Department to inspect the well development impoundments, especially those that do not require an Erosion and Sediment Control permit under 25 Pa. Code Chapter 102.

Also, the rulemaking establishes that well development impoundments need to be restored within 9 months of completion of hydraulic fracturing of the last well serviced by the impoundment. Restoring these facilities is needed to ensure that an extension for restoration may be approved under §§ 78.65(c) or 78a.65(c). While extensions for well development impoundments are not directly addressed in Act 13, the Department believes it is reasonable to tie the restoration requirements associated with well sites to well development impoundments because well development impoundments are contingent on the existence of well sites being developed and should not exist in perpetuity on their own. The Department believes that the sites used for well development impoundments need to be returned to preconstruction contours and support the prior land uses that existed to the extent practicable. Land owners may request to the Department in writing that the impoundment embankments not be restored provided that the synthetic liner is removed.

Mine Influenced Water.

In §§ 78.59b(h) and 78a.59b(h), the final-form rulemaking allows operators to request to store mine influenced water in well development impoundments. This provision seeks to codify the existing practices outlined in the Department's white paper, "Establishment of a Process for Evaluating the Proposed Use of Mine Influenced Water (MIW) for Natural Gas Extraction." Further, the purpose of these provisions is to promote the voluntary use of MIW by the oil and gas industry.

Some commenters were concerned about the potential to allow operators to store MIW in well development impoundments. These commentators assert that the quality of MIW varies greatly throughout the Commonwealth and the term includes MIW that has been treated, which may be very high quality. The Department disagreed with these commentators because §§ 78.59b(h) and 78a.59B(h) specify that before MIW is allowed to be stored in a well development impoundment, the Department must review and approve the storage based on a variety of factors including the quality of the MIW and the risks of storage of the water. MIW that does not meet the Department's water quality standards to be stored in a well development impoundment may not be stored in a well development impoundment. The Department believes that allowing the use of MIW for well development has a positive impact on the environment by finding a beneficial use for MIW that also reduces the consumption of freshwater from the Commonwealth's waterways. Encouraging the use of alternative water sources, including recycled water, MIW and treated wastewater, has been supported by the STRONGER organization in order to provide additional sources of water for operators to use for well development purposes.

Security Issues (fences)

Section 78.59b(e) and 78a.59b(e) of the final-form rulemaking require that a fence must completely surround a well development impoundment to prevent unauthorized acts of third parties and damage caused by wildlife unless an individual is continuously present at the impoundment. There were comments from operators who were concerned that no matter what type of fence they erect around an impoundment, it could never absolutely prevent entry. This provision is needed due to the size and depth of many well development impoundments plus the slickness of the installed liner. Additionally, this provision is needed to prevent unintended entry by landowners or other members of the public. Fences are also needed to deter wild life from damaging the structural integrity of these facilities. Well development impoundment liners can easily be damaged by large animals and even smaller ones with claws trying to escape after falling in.

Elimination of Centralized Impoundments

Section 78.59c(a) and 78a.59c(a) of the final-form rulemaking requires all centralized wastewater impoundments to comply with permitting requirements in Subpart D, Article IX. For all centralized impoundments authorized by a Dam Permit for a Centralized Impoundment Dam for Oil and Gas Operations (DEP #8000-PM-OOGM0084) that exist at the effective date of this rulemaking, those centralized impoundments must be closed or obtain a permit in accordance with Subpart D, Article IX. These requirements are needed to ensure that these facilities are regulated in the same manner as other waste transfer facilities in the Commonwealth. Another reason is that there have been recent cases of liner failures associated with facilities constructed under the Dam Permit for a Centralized Impoundment Dam for Oil and Gas Operations (DEP #8000-PM-OOGM0084).

When initially proposed, the rule included provisions to codify the Department's existing Centralized Impoundment permit program by providing technical specifications for construction and operation of centralized waste storage impoundments. The Department received significant public comment on this provision. For the reasons stated above, the Department has determined that all future centralized wastewater impoundments will be regulated by the Department's Waste Management Program.

The Department disagrees with commenters who were of the opinion that the final rulemaking essentially bans all centralized impoundments. The Department also disagrees with the commenters assertions that the regulations impose disparate requirements or disproportionate costs on the oil and gas industry. The final rulemaking requires all centralized impoundments to comply with permitting requirements in Subpart D, Article IX which will ensure that Chapter 78 does not result in disparate requirements or disproportionate costs on one particular economic or extractive sector. Subpart D, Article IX contains the requirements for managing residual waste properly, and these requirements apply to residual waste that is generated by any type of industrial, mining or agricultural operation.

Onsite Disposal

Chapter 78 retains onsite disposal requirements for conventional operators in Section 78.62-63. These provisions were retained because these requirements have existed in Chapter 78 for decades allowing the disposal of residual wastes including contaminated drill cuttings in a pit at conventional well sites and by land application without significant harm to public health and safety or the environment given the volumes involved in compliance Chapter 78. The Department retained these provisions in Chapter 78 in part because the cost of disposing wastes at a landfill may be overly burdensome for many conventional operators.
In § 78.62(a)(9), a well operator disposing residual waste on a well site in a pit must have a soil scientist or other similarly trained person determine that the pit bottom is 20 inches above the seasonal high groundwater table prior to using the pit. The Department received comments asking for clarification on who is qualified to make the determination that the pit bottom is at least 20 inches above the seasonal high groundwater table. The Department notes that the rule does not exclusively require this determination to be made by a soil scientist, but instead it allows the determination to be made by a soil scientist or other similarly trained person. The Department believes that training can be provided to conventional oil and gas operators to ensure they have the skills necessary to accurately identify the seasonal high groundwater table and comply with this requirement without having to hire a professional soil scientist in all cases. The purpose of this requirement is to ensure that they are in compliance with the requirement that the pit bottom be a minimum of 20 inches above the seasonal high groundwater table – a Chapter 78 requirement since 1989. Under the existing requirements, conventional operators have to conduct an evaluation of the soils beneath the bottom of their pit locations. The additional demonstration required in the final-form rulemaking is needed to ensure that conventional operators document their determinations that their pits meet this long standing regulatory requirement prior to using them. Making this requirement even more important is the fact that once the liner is placed into the pit and the pit is put into service, it is often nearly impossible for the Department to make a determination in the field regarding compliance with this requirement. The Department does not believe that this new requirement presents any significant new burden on conventional operators.

Conversely, in §§ 78a.62 and 78a.63, a permit is required for the same activities for residual wastes generated at unconventional well sites. These provisions are necessary due to the volumes of wastes generated and the chemical characteristics of the shale formations targeted.

The rulemaking requires unconventional operators to obtain a permit from the Department in order to dispose of residual waste, including contaminated drill cuttings, in a pit at the well site or by land application. These provisions are necessary to ensure that (1) the residual waste is properly characterized; (2) disposal pits are designed, sited and constructed; and (3) groundwater tables and soils are assessed in accordance with the Department's specifications. This requirement will ensure that groundwater is protected.

Landowner Notification

Comments were received that landowners should receive notification when onsite disposal occurs on their property. The Department agreed and amended the rulemaking to include the provision in §§ 78.62(a)(5), 78.63(a)(5). This allows the landowner to know of the location of the disposal area on their property.

Floodplain disposal restriction

The 2012 Oil and Gas Act § 3215(f)(1)(i) states that no well site may be prepared or well drilled within any floodplain if the well site will have a pit or impoundment containing drilling cuttings, flowback water, produced water or hazardous materials, chemicals or wastes within the floodplain. The Department incorporated this statutory requirement into § 78.62(a)(7) by not allowing the disposal of residual waste, including drill cuttings in a pit located within a floodplain. This will ensure that waters of the Commonwealth are protected and that residual wastes encapsulated in a pit will not be compromised by floods.

Containment

Secondary containment around oil and condensate tanks

Existing regulations in § 78.64 require secondary containment that meets federal statute 40 CFR Part 112 (relating to oil pollution prevention) to be implemented around oil tanks in order to prevent the discharge of oil into Waters of the Commonwealth. The Department has expanded this requirement in §§ 78.64 and 78a.64 to include tanks that contain condensate (light liquid hydrocarbons) because the United States Environmental Protection Agency considers condensate that is liquid at atmospheric pressures and temperatures to be "oil."

This final-form rulemaking removed the provision requiring secondary containment for singular tanks with a capacity of at least 660 gallons in §§ 78.64 and 78a.64. Sections 78.64 and 78a.64 in the final-form rulemaking require secondary containment for a tank or tanks with a combined capacity of at least 1,320 gallons. The purpose of this revision is to be consistent with Federal Spill Prevention, Control and Countermeasure Plan regulations at 40 CFR Part 112.

The final-form rulemaking added definitions for "primary containment" and "secondary containment" in §§ 78.1 and 78a.1. These terms are used throughout the rulemaking when referring to specific types of containment. The purpose of these additions to the rulemaking was to provide clarity. Many commentators commented that the terminology related to containment in the proposed rulemaking was confusing.

The final-form rulemaking in §§ 78.64(e) and 78a.64(e) require that existing condensate have secondary containment within two years of the regulations going into effect, or at the time the tank is replaced, refurbished or repaired, whichever is sooner. The purpose of these provisions is to ensure that secondary containment is installed for existing condensate tanks as they are replaced, refurbished or repaired to minimize spills and releases and ensure protection of public health, safety and the environment. The primary cause for pollution to the environment by oil and gas operations on well sites is unauthorized releases of regulated substances onto the ground. Secondary containment of all regulated substances is necessary to drastically reduce the potential for pollution on well sites.

Secondary containment at unconventional well sites

Section 78a.64a provides the secondary containment requirements at unconventional well sites. Section 3218.2 of the 2012 Oil and Gas Act establishes the requirements for secondary containment systems and practices for unconventional well sites. Accordingly, the provisions in § 78a.64 are needed to implement the statutory requirements.

According to Section 3218.2 of the 2012 Oil and Gas Act, secondary containment at unconventional well sites must be used on the well site when any equipment used for any phase of drilling, casing, cementing, hydraulic fracturing or flowback operations is brought onto a well site and when regulated substances are brought onto or generated at the well site. Section 78a.64a of the final-form rulemaking requires that all regulated substances, except fuel in equipment or vehicles, be managed within secondary containment. It has been the Department's experience that the primary cause for pollution to the environment by oil and gas operations on well sites is unauthorized releases of regulated substances onto the ground. Secondary containment of all regulated substances is necessary to drastically reduce the potential for pollution on well sites.

Section 78a.64a(c)(2)-(3) establishes chemical compatibility and maximum permeability standards be met for materials used for secondary containment at unconventional well sites. The proposed rulemaking specified that liner compatibility shall satisfy ASTM Method D5747 Compatibility Test for Wastes and Membrane liners. Some commentators felt that this standard for testing chemical compatibility is time consuming, expensive, intended for landfill liners, and may not be practicable to allow for other materials to be used that meet the maximum permeability standard. For this reason, the Department amended § 78a.64a(c)(3) in the final-form rulemaking to allow for chemical compatibility testing to be determined by a method approved by the Department. The purpose of this provision is to allow for the proper and most practicable testing methodology to be used based upon the material used for secondary containment at an unconventional well site.

Section 78a.64a of the final-form rulemaking requires secondary containment open to the atmosphere to be able to hold the volume of the largest aboveground primary container plus an additional 10% for precipitation. Removal of precipitation from secondary containment is required once the 10% of excess capacity is diminished. Stormwater that comes into contact with regulated substances stored within the secondary containment needs to be managed as residual waste. Double walled tanks capable of detecting leaks from primary containment are also allowed to be used. The Department received comments arguing that Section 3218.2(d) of Act 13 does not require secondary containment systems. The Department interprets Section 3218.2(d) of Oil and Gas Act of 2012 to mean that the container that additives, chemicals, oils or fuels are stored in is considered to be primary containment. Therefore, the containment capacity referred to that must be able to hold the contents of the largest container plus 10% for precipitation is secondary containment. Any other interpretation of Section 3218.2(d) would render the final phrase of the subsection ("…unless the container is equipped with individual secondary containment.") irrelevant. These provisions are needed to implement Section 3218.2(d) of the 2012 Oil and Gas Act.

Section 78a.64a(e) requires operations to inspect secondary containment weekly. The purpose of this provision is to ensure integrity. This provision further requires repairs to damaged or compromised secondary containment must be done as soon as practicable. Additionally, Section 78a.64a(e) requires secondary containment inspection and maintenance records to be maintained and made available at the well site until the well site is restored. The Department received comments stating that for many operators, it is not practical to store hard copies of inspection reports and maintenance records at the well site. These commentators asserted that the Department should allow for operators to provide these reports electronically to the Department upon request. The Department believes that since containment systems will be employed during drilling, casing, cementing, hydraulic fracturing and flowback operations, it is reasonable to make inspection reports and maintenance records available at the well site, because the site is normally manned during these operations. The Department is not requiring that hard copies be stored on site, but is requiring that operators be capable of making these reports available upon request (physically or electronically) at the site at the time of the request. The purpose of this requirement is so that the Department may determine that operators are doing their due diligence with secondary containment inspection and maintenance at the time of inspection.

Language pertaining to subsurface containment systems found in the original proposed rulemaking has been removed after receiving comments that they should not be allowed and the Department concurred that subsurface containment systems are too impractical to be employed as a secondary containment system because they are difficult to inspect and they would require remedial steps to address the contaminated material within them whenever a spill would occur.

Site Restoration

Sections 78.65 and 78a.65 outline the requirements related to a well operator's obligation to restore the well site. Section 3216 of the Oil and Gas Act requires well operator's to "restore the land surface within the area disturbed in siting, drilling, completing and producing the well" and contains specific well site restoration requirements. 58 Pa.C.S. § 3216. Some of these statutory provisions were amended in Act 13 of 2012. The provisions in §§ 78.65 and 78a.65 are needed to implement the requirements in the statute. In large part, these provisions restate the statutory requirements and incorporate the Department's interpretation of these requirements as currently outlined in the "Policy for Erosion and Sediment Control and Stormwater Management for Earth Disturbance Associated with Oil and Gas Exploration, Production, Processing, or Treatment Operations or Transmission Facilities", Document No. 800-2100-008, which was finalized on December 29, 2012.

In addition to implementing the statutory requirements related to well site restoration, §§ 78.65 and 78a.65 are needed because permanent changes to the surface of the land resulting from earth disturbance activities have the potential to cause pollution. In many watersheds throughout the state, flooding problems from precipitation events, including smaller storms, have increased over time due to changes in land use and ineffective stormwater management. This additional flooding is a result of an increased volume of stormwater runoff being discharged throughout the watershed. This increase in stormwater volume is the direct result of more extensive impervious surface areas, combined with substantial tracts of natural landscape being converted to lawns on highly compacted soil or agricultural activities. The problems are not limited to flooding. Stormwater runoff carries significant quantities of pollutants washed from the impervious and altered land surfaces. The mix of potential pollutants ranges from sediment to varying quantities of nutrients, organic chemicals, petroleum hydrocarbons, and other constituents that cause water quality degradation.

Improperly managed stormwater causes increased flooding, water quality degradation, stream channel erosion, reduced groundwater recharge, and loss of aquatic species. But these and other impacts can be effectively avoided or minimized through better site design that minimizes the volume of stormwater generated and also requires treatment. Post Construction Stormwater Management (PCSM) requirements are already codified in Ch. 102.8 and are needed to prevent pollution from improperly managed stormwater, and requires utilization of stormwater management techniques that achieve stormwater runoff volume reduction, pollutant reduction, groundwater recharge and stormwater runoff rate control for all runoff events. The requirements of §§78.65 and 78a.65 are not more or less stringent than Ch. 102.8, but are a reasonable approach to adapting the requirements of this section where needed for the industry as detailed below.

Sections 78.65 and 78a.65 in the final-form rulemaking were amended after the Department received comments on the proposed rulemaking. Many of the amendments in this section were needed to provide clarity. However, substantively, the changes to the well site restoration sections do not deviate greatly from the proposed regulatory language.

Several commentators were of the opinion that the proposed restoration requirements included in the draft final rulemaking were not stringent enough and should require more than restoration to approximate original conditions. These commenters want to see the restoration requirements require operators to reestablish prior existing biological communities and ecosystems as well as reestablish the entire site to its exact pre-existing conditions. This position proposes making §§ 78.65 and 78a.65 more stringent than 25 Pa. Code § 102.8. The Department does not believe that it is necessary to include technical performance standards including requirements for type and density of perennial vegetation, soil characteristics and drainage patterns in this section because those issues are already appropriately addressed by the requirements. The Department has determined that projects meeting the requirements in this final-form rulemaking will not pose a threat of significant environmental harm.

The Department included the phrase "to the extent practicable" in the definition of "approximate original conditions" in recognition of the fact that restoration to original contours may not always be feasible. Subsections 78.65(a)(1) and 78a.65(a)(1) allow operators broad discretion to ensure wells and well sites can be operated safely while also complying with the site restoration requirements in the 2012 Oil and Gas Act.

Restoration timeline/2 year extension

For post-drilling, Sections 78.65(a)(1) and 78a.65(a)(1) require restoration of the well site within 9 months after completion of drilling of all permitted wells on the site or within 9 months of the expiration of all existing well permits on the site, whichever is later. For post-plugging, Sections 78.65(a)(2) and

78a.65(a)(2) require restoration within 9 months after plugging the final well on a well site. These provisions restate the requirements in Section 3216(c)-(d) of the 2012 Oil and Gas Act.

Sections 78.65(c) and 78a.65(c) specify that an operator may request to extend the restoration period. This provision is needed to implement Section 3216(g) of the 2012 Oil and Gas Act. Operators may request an extension of the restoration timeframe because the extension will result in less earth disturbance, increased water reuse or more efficient development of the resources or if restoration cannot be achieved due to adverse weather conditions or a lack of essential fuel, equipment or labor.

For post-drilling, the regulation requires restoration of the well site within 9 months after completion of drilling of all permitted wells on the site or within 9 months of the expiration of all existing well permits on the site, whichever is later. For post-plugging, it requires restoration within 9 months after plugging the final well on a well site. The restoration time frames are consistent with requirements in the 2012 Oil and Gas Act.

Under current regulation, a well site must be restored within 30 days after expiration of the drilling permit, if the site is constructed and the well is not drilled. This was originally retained in the ANFR. In response to comments, Sections 78.65(a)(3) and 78a.65(a)(3) in the final-form rulemaking amend the timeframe for such restoration to nine months. The purpose of this provision is to provide an appropriate timeframe to achieve compliance with vegetation and stability requirements. Nine months is appropriate because it will allow operators to conduct restoration work during growing seasons and will reduce environment impacts outside of growing seasons.

PCSM requirements

Sections 78.65(d) and 78a.65(d) address areas not restored on a well site. The purpose of these provisions is to provide clarity between restoration under Chapter 78 and compliance with Chapter 102. These provisions are needed to distinguish between (1) "areas not restored" – areas not included on the restoration plan and other remaining impervious areas and (2) areas restored to meadow in good condition or better or areas that otherwise incorporate antidegradation best available combination of technologies (ABACT) or nondischarge PCSM best management practices (BMPs). "Areas not restored" do not fall within the provisions in§ 102.8(n) and therefore must meet the requirements, inter alia, of § 102.8(g). "Areas not restored" include areas where there are permanent structures or impervious surfaces, therefore runoff produced from these areas must be tributary to permanent PCSM BMPs to ensure the runoff will be managed in accordance with the requirements of § 102.8.

Written Restoration Plan

Section 78.65(b)(7) in the final-form rulemaking provides that conventional operators who are required to obtain permits under § 102.5(c) may develop a written restoration plan addressing the requirements in Section 78.65(b)(1)-(6) and that this restoration plan constitutes a restoration plan for purposes of § 102.8(n). This provision is needed to clarify that this final-form rulemaking does not require a written restoration plan. Further, this final-form rulemaking does not require a written plan to all well sites. In response to comments, operators do not need to develop written restoration plans for all well sites and has modified the regulation to require development of written restoration plans only for well sites which require permit coverage under § 102.5(c) (relating to permit requirements).

Landowner consent for storing equipment not needed for production (agreements vs lease)

In §§ 78.65(a)(1) and 78a.65(a)91), drilling supplies and equipment not needed for production may only be stored on the well site if written consent of the landowner is obtained. The need for express landowner consent is consistent with the requirements in Section 3216 of the 2012 Oil and Gas Act. The requirement for consent allows the landowner to know what is being stored on their property, where a blanket allowance under a lease agreement may not afford such transparency.

Waste disposal information in restoration report

Sections 78.65(e) and 78a.65(e) of the final-form rulemaking outline the post-drilling restoration report requirements. These provisions require submission of information related to waste disposal. These provisions are needed because details regarding the type of waste, as well as volume, leachate analysis and physical location are not captured in the waste reporting requirements. This section also requires operators to forward a copy of the report to the surface landowner. This information is critical for the landowner to be aware of where waste is located so it can be avoided in the event of future earth moving activities on the landowner's property.

Spill Response

Sections 78.66 and 78a.66 of the final-form rulemaking outline the requirements related to reporting and remediating spills and releases of regulated substances on or adjacent to well sites and access roads. Sections 78.66 and 78a.66 are needed to ensure that all spills or releases of regulated substances on conventional and unconventional oil and gas well sites and access roads are remediated in a responsible manner that protects public health, safety and the environment. The purpose of the provisions in these sections is to clarify the requirements regarding reporting and remediating spills and releases of regulated substances on or adjacent to well sites and access roads. Further, the purpose of the provisions in these sections is to clarify that the operator or responsible party shall remediate an area affected by a spill or release and outlines two different remediation options. These provisions are needed because spills or releases from containment of regulated substances at oil and gas well sites pose a substantial risk to the environment and public health, including impacts to water resources. These provisions ensure that oil and gas operators of both conventional and unconventional wells have an obligation to report and properly remediate spills and releases in a timely manner.

Some commenters felt that § 78.66(b)(2) reporting requirements went beyond the scope of what is required in § 91.33. The Department believes that the final rulemaking for subsection (b)(2) will serve as guidance for the responsible party to provide enough information, to the extent known, necessary for the Department to properly asses the reported spill incident, so the appropriate initial response can be employed by the Department.

Many commenters were concerned that the public and other government agencies were not made aware of all spills and releases that occur at both conventional and unconventional well sites. The regulations require that operators report releases within 2 hours of discovery to the Department electronically through its web site. This information will then be loaded directly into a spill and release database. The Department will utilize this database to create an electronic spill and release reporting and tracking system available for the public and government entities to receive up-to-date information concerning spills and releases and remedial actions at oil and gas operations. The system will be similar to the

Department's eNOTICE system, which allows users to get information about their communities and the facilities they are interested in delivered directly via email.

The regulation cross-references § 91.33, which requires the operator or other responsible party to take necessary corrective actions, upon discovery of the spill or release, to prevent the substance from polluting or threatening to pollute the Waters of the Commonwealth; damage to property; or impacts to downstream users of Waters of the Commonwealth. This concern was expressed in numerous comments over the possible pollution of private water wells due to oil and gas activity. To help address this, the operator or other responsible party will be required to identify water supplies that have been polluted or for which there is potential for pollution as a result of a spill or release at a conventional or unconventional well site. When a water supply is determined to have been polluted by oil and gas operations, it shall be restored or replaced in accordance with Section 3218 of the 2012 Oil and Gas Act and §§ 78.51 or 78a.51.

The spill or release area must then be remediated appropriately through Act 2 (of 1995) standards and processes. One of the primary reasons the Department requires remediation of spills to an Act 2 standard is because the operator is typically not the owner of the land where the regulated substance is spilled or released. It is simply unreasonable to leave behind contaminants at levels that may pose a health risk as a result of oil and gas operations on another person's property.

The Department's Act 2 standards explicitly reflect the risks various compounds and elements pose to human health and the environment, and have been applied successfully to thousands of successful remediation projects over the past 20 years. The final-form rulemaking specifically provides flexibility to oil and gas operators to address small spills and releases, fully-contained releases and larger spills and releases in a flexible and straightforward manner.

There were a few comments from operators who expressed concern over time constraints of report submittals that are in the regulation for various portions of the remediation process. It is both reasonable and appropriate to require operators to carry out remedial actions promptly and not let contamination linger in the environment. The timeframes established in the final rulemaking are modeled on the timeframes established for corrective actions for releases from storage tanks in 25 Pa. Code Chapter 245. The storage tank corrective action process was established in 1993 and has been used successfully for thousands of storage tank cleanups, both before and after the passage of Act 2 in 1995. The tank regulations were updated in 2001 to harmonize the regulations with Act 2 and the Act 2 implementing regulations in 25 Pa. Code Chapter 250. These timeframes are appropriate and have built-in flexibility to address the unique considerations posed by each remedial site. Finally, the Department notes that the timeframes establish requirements for the steps that will lead to completion of the corrective action but do not establish a timeframe by which demonstration of attainment of an Act 2 standard must be made. The Department recognizes that each site poses unique challenges and a one-size-fits-all completion date requirement is not appropriate.

Borrow Pits

Sections 78.67 and 78a.67 outline the requirements related to borrow pits. Section 3273.1(b) of the 2012 Oil and Gas Act provides a limited exemption the Noncoal Surface Mining Conservation and Reclamation Act. The provisions in this final-form rulemaking are needed to implement and clarify the scope of that exemption and existing statutory and regulatory requirements. The purpose of these provisions is to ensure that all borrow pits used in support of conventional and unconventional oil and gas development are constructed and reclaimed in a responsible manner that protects public health, safety and the environment.

These borrow pits share the same environmental risks as other borrow pits that are not used by the oil and gas industry. Sections 78.67(a) and 78a.67(a) state that while certain pits are exempt from the permitting requirements in Section 3273.1 of the Noncoal Surface Mining Conservation and Reclamation Act, those facilities must still comply with Chapter 77, Subchapter I (Environmental Protection Performance Standards), Chapter 102 and other applicable laws.

Sections 78.67(b) and 78a.67(b) require the registration of the location of existing borrow pits within 60 calendar days after the effective date of the final rulemaking and registration of new borrow pits before there are built. This will be done electronically through the Department's website. There were a few comments from operators that this would be burdensome on industry. The Department has determined that the registration process is reasonable and appropriate to facilitate the inspection and regulation of the borrow pits and to provide public transparency of where these borrow pits are located. This is especially important since a number of borrow pits are constructed on public lands, such as in the Allegheny National Forest.

Sections 78.67(c) and 78a.67(c) require operators to restore, or seek permitting for, facilities that are for any reason no longer exempt under Section 3273.1. Borrow pits must be restored within 9 months after completion of drilling. Because a borrow pit may service one or several well pads other than the pad on which it is located, Sections 78.67(c) and 78a.67(c) provide for restoration timelines related to either the completion of drilling or the expiration of well permits. As an alternative to restoration upon either of these triggers, the sections allow an operator to seek a noncoal surface mining permit or alternative relevant exemption, such as a restoration extension approved under 78.65(d) (relating to site restoration).

Pipelines

Sections 78a.68 – 78a.68b of the final-form rulemaking addresses activities for gathering pipelines, HDD and well development pipelines related to unconventional operations. The construction, operation, maintenance, repair, and removal of oil and gas gathering and well development pipelines can impact the health, safety and welfare of the public and the environment. Sections 78a.68, 78a.68a and 78a.68b pertain to oil and gas gathering lines that fall under the jurisdiction of the Department's Office of Oil and Gas which are exempt from federal jurisdiction. While the Department agrees that gathering lines, horizontal directional drilling for gathering lines and well development pipelines are required to comply with 25 Pa. Code Chapters 102 and 105, the Department also deems §§ 78a.68, 78a.68a and 78a.68b necessary to address safety and environmental issues associated with gathering lines, HDD for gathering lines and well development pipelines due to the frequency and magnitude of these activities in the Commonwealth.

The primary focus of §§ 78a.68, 78a.68a and 78a.68b is to minimize direct impacts to waters of the Commonwealth; minimize sediment pollution, enhance top soil conservation and protect locations of threatened or endangered species habitat. The rulemaking is consistent with the Pennsylvania Constitution and applicable statutes and strikes a reasonable balance between protection of these natural resources and the costs incurred by the oil and gas industry.

§78.68 Oil and gas gathering pipelines

Section 78a.68(a) of the final-form rulemaking applies to unconventional operations only and requires the use of highly visible flagging, markers or signs to be used to identify the shared boundaries of the limit of disturbance (LOD), wetlands and locations of threatened or endangered species habitat prior to land clearing. These provision are needed to delineate special area boundaries in the field i.e. LOD, jurisdictional streams and wetlands as well as endangered species habitat otherwise unseen or not readily visible to reduce the likelihood of unintentional disturbance during clearing and grubbing or other earthmoving activities. Without persistent, accurate and consistent visual demarcation of these boundaries, there is an increased likelihood of these areas being significantly disturbed during construction and restoration activities.

Section 78a.68(c) of the final-form rulemaking protects topsoil by requiring segregation of topsoil and subsoil during its excavation, storage and backfilling. This provision is needed because the segregation of topsoil in all areas and phases is critical to successful restoration of pipeline right of ways and favors the industry by reducing the need for, the cost of and the additional impact from importing topsoil to restore healthy vegetation after construction.

Section 78a.68(c)(4) of the final-form rulemaking requires native and imported topsoil used for pipeline right of way restoration must be of equal or greater quality than the original topsoil to ensure the land is capable of supporting the uses that existed prior to earth disturbance. This provision is needed to clarify that it is acceptable to import topsoil provided that the topsoil used for restoring the pipeline right of way is of a quality capable of supporting the prior preexisting potential uses of the land.

Section 78a.68(e)-(f) of the final-form rulemaking requires equipment refueling and staging areas must be out of floodways and least fifty feet away from a body of water. The proposed setback for refueling and material staging areas from water bodies is appropriate and consistent with other regulatory requirements found in 25 Pa. Code Chapter 105. The Department did receive some comments that the Department should allow for exceptions to the 50-foot distance restriction for material staging areas. The Department agreed and as a result, Subsection 78a.68(f) has been modified to allow for materials staging within the floodway or within 50 feet of a water body if first approved in writing by the Department.

Section 78a.68(g) of the final-form rulemaking requires that all buried metallic gathering pipelines shall be installed and placed in operation in accordance with federal statute 49 CFR Part 192, Subpart I or 195, Subpart H relating to requirements for corrosion control. These provisions are needed to implement Section 3218.4(a) of the Oil and Gas Act which requires standards for the installation and placement of metallic pipelines, including related corrosion control requirements.

§ 78a.68a. Horizontal directional drilling for oil and gas pipelines

Section 78a.68a of final-form rulemaking requires horizontal directional drilling for oil and gas pipelines HDD must comply with the regulatory requirements found in 25 Pa. Code Chapters 102 and 105. The language pertaining to HDD for oil and gas pipelines in Chapter 78 in needed to clarify existing requirements and address issues that frequently arise during HDD activities conducted by the oil and gas industry.

Section 78a.68a(b) of the final-form rulemaking includes a requirement for a PPC plan for HDD with a site specific contingency plan that describes the measures to be taken to control, contain and collect any discharge of drilling fluids and minimize impacts to waters of the Commonwealth. This provision is needed because the heightened potential for pollution to waters of the Commonwealth that HDD creates necessitates a separate PPC plan for this specific activity. A separate PPC plan is not required for HDD activities provided that the PPC plan developed under § 78a.55 meets the requirements in section § 78a.68a.

Section 78a.68a(g) of the final-form rulemaking requires that bodies of water and watercourses over and adjacent to HDD activities be monitored for any signs of drilling fluid discharges. Many inadvertent returns of HDD fluids express themselves hundreds of feet from the actual bore hole. Therefore, monitoring bodies of water and watercourses during HDD activities will detect impacts as soon as they occur.

Section 78a.68a(c) of the final-form rulemaking includes a requirement to immediately notify the Department of a HDD drilling fluid discharge or loss of drilling fluid circulation. This is consistent with the reporting requirements in § 91.33.

Section 78a.68a(f) of the final-form rulemaking requires HDD drilling fluid additives other than bentonite and water to be approved by the Department prior to use. All approved horizontal directional drilling fluid additives will be listed on the Department's web site to eliminate the need for preapproval prior to each use. This will ensure that HDD operators know which additives are preapproved for use without having to wait for the Department to review and approve a drilling additive.

§ 78a.68b. *Well development pipelines for oil and gas operations.*

Section 78a.69b(a) of the final-form rulemaking requires that well development pipelines that transport flowback water and other wastewaters be installed aboveground. This provision is needed because buried pipelines cannot be easily inspected for leaks or damage while aboveground pipelines can be visually inspected daily when in use and if leaks or defects are observed, repairs or other effective corrective measures can be taken expeditiously and thereby reducing or avoiding an accidental pollutional event.

Section 78a.68b(c) of the final-form rulemaking specifies that well development pipelines may not be installed through existing stream culverts, storm drain pipes or under bridges that cross streams without approval by the Department under § 105.151 (relating to permit application for construction or modification of culverts and bridges). This provision is needed because most culverts, storm drains and bridges that cross streams are designed and sized taking the maximum anticipated flow of water into consideration. Placing well development pipelines in/under them displaces their capacity to carry their designed load, which could lead to localized flooding as a result.

Sections 78a.68b contains certain safety measures with well development pipelines used to transport fluids other than fresh ground water, surface water, and water from water purveyors or approved sources. They must be pressure tested prior to being first placed into service and after the pipeline is moved, repaired or altered. They must have shut off valves, check valves or other methods of segmenting the pipeline placed at designated intervals that prevent the discharge of more than 1,000 barrels of fluid. They may not have joints or couplings on the segments that cross waterways unless secondary containment is provided. Highly visible flagging, markers or signs need to be placed at regular intervals along the well development pipeline. They cannot be used to transport flammable materials. The STRONGER organization recommends that state programs should address the integrity of pipelines for transporting and managing hydraulic fracturing fluids off the well pad. The Department received comments that endorsed these provisions and comments that were against their implementation. These safety measures are necessary to protect the environment by providing mechanisms that help identify their locations; isolate sections that are compromised, minimizes direct leaks into waterways and eliminates the risk of fires.

Section 78a.68b(l) of the final-form rulemaking requires well development pipelines to be removed when the well site is restored. This provision is needed because well development pipelines are meant to be temporary and used for the sole purpose of well development activities at a well site. Well development pipelines need to be removed when the well site get restored in accordance with the well site restoration requirements. Permanent pipelines used for transportation of fluids are beyond the scope of this rulemaking.

Section 78a.68b(m) of the final-form rulemaking requires that the operator maintain certain records regarding well development pipelines, including their location, type of fluids transported, the approximate time of installation, pressure test results, defects and repairs. The records need to be retained for a year after their removal and be made available to the Department upon request. The Department received a comment that well development records should be retained by operators for two years after their removal. The Department believes one year is a sufficient amount of time for record retention due to the temporary nature of these pipelines.

Section 78a.68b(n) of the final-form rulemaking requires operators to obtain Department approval for well development pipelines in service for more than a year. The Department believes that a well development pipeline that is in service for over a year becomes more than a temporary use and wants to know about its location and use.

Water Management Plans

Section 78a.69 outlines the requirements for water management plans. This section applies to unconventional operations only. Section 3211(m) of the 2012 Oil and Gas requires water management plans for unconventional operations. The provisions in this rulemaking are needed to implement those statutory requirements. These provisions largely codify existing requirements to protect quality and quantity of water sources in the Commonwealth, including freshwater resources, from adverse impacts to the watershed considered as a whole from potentially inappropriate withdrawals of water. Further, the final-form rulemaking protects water quality and quantity by ensuring water is available to other users of the same water source and protects and maintains the designated and existing uses of the water source. This final-form rulemaking mirrors most of the requirements of the Susquehanna River Basin Commission and the Delaware River Basin Commission to ensure that requirements are consistent statewide, regardless of which river basin an operator withdraws water from. This statewide consistency also eliminates uncertainty and inconsistency for the regulated community. Finally, water users, including public water supplies, private water supplies, industrial water users as well as the regulated community benefit from the regulation as it protects water sources from over withdrawals and potential degradation to water quality.

Road Spreading of Brine

In Pennsylvania geology, brine (saltwater) is present in most oil and gas producing formations. When oil or gas is produced from a well, brine is also brought to the surface and is typically separated into a holding tank. Throughout the history of conventional oil and gas development, brine has been beneficially used in dust suppression and road stabilization activities on dirt roads and also for de-icing in the winter months. For about the last 12 years, the Waste Management Program within DEP has issued a general permit (WMGR 065) for de-icing activities, which allows brine from conventional wells to be spread as a means for winter weather road treatment. In 1998, the Department's Oil and Gas Management Program issued a Technical Guidance Document *Approval of Brine Roadspreading Plans* (Doc. No.550-2100-007) to describe to operators and other users how the Department will review all plans for the beneficial use of brine for dust control and road stabilization to ensure compliance with applicable statutes and regulations and protecting water resources.

The rulemaking in §§ 78.70 and 78.70a will raise current policies for road-spreading of brine for dust control and road stabilization and the recently expired WMGR065 general permit for anti-icing and de-icing for beneficial use on roadways to the level of regulations, thus allowing for consistent regulation and enforcement from the Department. By incorporating all the relevant Department requirements for post-production uses of brine into Chapter 78 and under the Oil and Gas Program's oversight, it will ensure these activities are properly approved on an annual basis and monitored by the Oil and Gas Program. This approach will ensure post production uses of brine from conventional oil and gas wells are properly applied to roadways and do not impact waters of the Commonwealth. The rulemaking provides a more economical option for operators to manage oil and gas well production brine. Plans must be submitted and approved on an annual basis. Detailed information for these plans must be submitted so the Department can conduct a thorough review of where the brine is coming from; what is in the brine and where it is going.

Production Reporting

Section 78a.121(a) of the final-form rulemaking contains the production report requirements for unconventional operators. This provision was amended between the proposed rulemaking and this final-form rulemaking and is needed to implement Act 173 of 2014, known as the Unconventional Well Report Act, which became effective on March 31, 2014, repealed 58 P.S. § 3222a.1 of the Oil and Gas Act of 2012 and required unconventional oil and gas well operators to file a monthly well production report.

Section 78a.121(b) of the final-form rulemaking requires information on the amount and type of waste produced and the method of disposal on a monthly basis within 45 days of the end of the month. The Department received significant comment on this provision from unconventional operators on the draft-final rulemaking.

Data analyses conducted by the Department, which compared 2013 and 2014 calendar year records from facilities that receive oil and gas waste for processing or disposal and from data reported by oil and gas operators in the Department's oil and gas electronic reporting (OGER) database, revealed that there are significant discrepancies in both the quantities of waste reported by oil and gas operators and also in the way the wastes are classified. More recent analyses have indicated that oil and gas operator reporting is improving; however, the same issues still exist. The current bi-annual reporting requirement is not conducive to correcting reporting discrepancies because the Department does not become aware of a reporting issue until a substantial amount of time has passed from when the waste was originally sent for processing or disposal. Monthly reporting promotes quicker recognition of reporting inaccuracies that can be rectified in a more reasonable timeframe.

The Department believes that the monthly timeframe with reporting due 45 days after the end of the month is clearly feasible for operators. Because the six-month reporting window includes data from June in the August report and December in the February report, operators are already compiling two months reporting data in that 45-day or they are out of compliance with the current regulation.

The Department believes that responsible operators are aware of and track their waste generation, transportation, treatment, storage and disposal and operating without such awareness is not a best management practice and is unacceptable in the Commonwealth. As a final note, the Department believes that the monthly reporting requirement strikes the appropriate balance between burden and benefit compared to other regulatory alternatives, such as keeping the current flawed six-month reporting system or imposing a load-by-load manifest system as is currently required for hazardous wastes.

Conventional operators are only required to report waste production from wells on an annual basis, not on a monthly basis as is required for unconventional well operators.

Question 11

(11) Are there any provisions that are more stringent than federal standards? If yes, identify the specific provisions and the compelling Pennsylvania interest that demands stronger regulations.

These regulations do not impose any requirements that are more stringent than federal standards, because there are no federal regulations that directly and specifically regulate the oil and gas industry and well sites. Pennsylvania has a compelling public interest in regulating the oil and gas industry due to the unique risks posed to the environment.

Question 12

(12) How does this regulation compare with those of the other states? How will this affect Pennsylvania's ability to compete with other states?

With this rulemaking, Pennsylvania will join a growing list of states to comprehensively address the regulation of surface activities and industry practices at oil and gas well sites. The Department reviewed the regulatory requirements of states with oil and gas drilling activity, but focused the majority of this comparison on the regulatory requirements of Colorado, Ohio, New York and West Virginia. Ohio, New York and West Virginia were chosen because they are neighboring states that have a similar history of conventional well drilling, and Pennsylvania shares portions of the same shale formations found in these three states that the unconventional drilling industry is targeting. Colorado was chosen because it is a state that shares similar topography with Pennsylvania, and they have also experienced the recent arrival of unconventional well drilling in their state and have recently enacted new drilling regulations in response. At this time, Ohio, West Virginia and Colorado are all currently updating their oil and gas drilling regulations.

Several sections of this final rulemaking will codify existing requirements of oil and gas operations and therefore should not alone affect Pennsylvania's ability to compete with other states. Water Management Plans (WMPs) have been a permit requirement for oil and gas operators since April 2009 and the final regulations are consistent with the requirements of the Susquehanna River Basin Commission. By making WMP requirements consistent statewide, operators will have more certainty regarding the requirements versus other states with river basin commissions that do not have the same level of consistency. Beneficial use of brine for road spreading and de-icing activities is another section that this regulation codifies existing permitting and planning requirements and therefore will not affect Pennsylvania's ability to compete.

Because New York maintains a moratorium on high volume hydraulic fracturing and no unconventional well drilling is occurring, Pennsylvania enjoys a clear competitive advantage with New York. Because of Pennsylvania's proximity to high natural gas consumptive markets in the Northeast, the Marcellus and other dry gas formations remain more attractive than other dry gas in the south and west such as the Barnett, Fayetteville and Haynesville Shale. In some portions of Pennsylvania, multiple shale layers can be targeted from the same well pad, allowing operators to minimize expense.

Most of the Department's final-form regulations are performance based in lieu of prescriptive standards to allow operators the flexibility of choosing the best option to meet compliance. It is through this approach to the final rulemaking and Pennsylvania's strategic location in the United States that will allow it to remain competitive with other oil and gas producing states while updating measures minimizing the potential for impacts to the environment from oil and gas well operations.

A comprehensive analysis of requirements from nearby states is provided below.

Protection of Water Supplies

The rulemaking establishes a statewide toll free phone number for people to call to request a water supply investigation by the Department to determine if the pollution or diminution was caused by oil and gas operations. This is a statutory requirement found in the 2012 Oil and Gas Act. 58 Pa.C.S. § 3218(b.2). The rulemaking establishes that the Department will investigate claims of water supply pollution or diminution potentially caused by oil and gas operations, which encompasses most activities associated with the oil and gas industry. If the Department finds that pollution or diminution was caused by the oil and gas operations or if it presumes the well operator responsible for polluting the water supply of the landowner or water purveyor under section 3218(c) of the 2012 Oil and Gas Act, the quality of a restored or replaced water supply has to be restored to the standards established under the Pennsylvania Safe Drinking Water Act (SDWA) (35 P.S. §§ 721.1 – 721.17), or is comparable to the quality of the water that existed prior to pollution if the water quality was better than SDWA standards.

Colorado

In Colorado, any person has the right to file a complaint with the Colorado Oil and Gas Conservation Commission (COGCC) related to oil and gas operations within the state. Colorado has a web site that allows a person to submit a complaint about their water supply. COGCC has a central complaint line if a person wishes to call in their concerns. Complaints about oil and gas operations can also be emailed to a provided email account. Colorado regulations require that no operator conducting any oil or gas operation shall perform any act or practice which shall constitute a violation of water quality standards or classifications established by the Water Quality Control Commission for waters of the state. Rule 207 gives the Commission the authorization to require that tests or surveys be made to determine the presence of waste or occurrence of pollution, when deemed necessary or advisable. The operator must provide evidence, such as soil or water samples, demonstrating the site has been cleaned-up to published standards established by COGCC in conjunction with Colorado Department of Public Health and Environment. These standards are listed in Table 910-1 of the 900 series of the Rules.

Ohio

In Ohio, the Ohio Department of Natural Resources (ODNR) – Division of Oil and Gas Resources Management conducts investigations when it receives complaints alleging water supply contamination, diminution or disruption by oil and gas operations. A complaint may be received by ODNR in writing, by e-mail, via phone, or in person. Technical staff responds within 24 hours. Section 1509.22 (F) of the Ohio Code gives ODNR – Division of Oil and Gas Resources Management the authority to require an owner/operator of an oil and gas well to replace the water supply of the property owner whose water supply has been substantially disrupted by contamination, diminution or interruption resulting from the owner's oil and gas operation. This includes supplies of water for domestic, agricultural, industrial or other legitimate use from an underground or surface source. The Ohio Department of Health (ODH) has established health-based standards for private water systems that are the same as the standards for public water supply systems established by the Ohio EPA and U.S. Environmental Protection Agency (EPA).

West Virginia

In West Virginia, the WVDEP Office of Oil and Gas requires formal water supply complaints be submitted in writing. W. Va. Code § 22-6-35 of the Office of Oil and Gas Regulations states, in any action for contamination or deprivation of a fresh water source or supply within one thousand feet of the site of drilling for an oil or gas well, there shall be a rebuttable presumption that such drilling, and such oil or gas well, or either, was the proximate cause of the contamination or deprivation of such fresh water source or supply.

West Virginia Code § 22-6A-18 of the Natural Gas Horizontal Well Control Act states that, unless rebutted by the defenses found in W. Va. Code § 22-6A-18(c) of the Natural Gas Horizontal Well Control Act, any action for contamination or deprivation of a fresh water source or supply within one thousand feet of the site of drilling for an oil or gas well, there shall be a rebuttable presumption that such drilling, and such oil or gas well, or either, was the proximate cause of the contamination or deprivation of such fresh water source or supply. W. Va. Code §22-6A-18 (e) of the Natural Gas Horizontal Well Control Act states, any operator shall replace the water supply of an owner of interest in real property who obtains all or part of that owner's supply of water for domestic, agricultural, industrial or other legitimate use from an underground or surface source with a comparable water supply where the secretary determines that the water supply has been affected by contamination, diminution or interruption proximately caused by the oil or gas operation, unless waived in writing by that owner.

W. Va. Code § 22-12-4(b) of the Groundwater Protection Act establishes standards for the maximum contaminant levels permitted for groundwater, but in no event shall the standards allow contaminant levels in groundwater to exceed the maximum contaminant levels adopted by the U.S. EPA pursuant to the federal Safe Drinking Water Act. The Secretary may set standards more restrictive than the maximum contaminant levels where it finds that such standards are necessary to protect drinking water use where scientifically supportable evidence reflects factors unique to West Virginia or some area thereof, or to protect other beneficial uses of the groundwater. For contaminants not regulated by the Federal Safe Drinking Water Act, standards for such contaminants shall be established by the Secretary to be no less stringent than may be reasonable and prudent to protect drinking water or any other beneficial use. Where the concentration of a certain constituent exceeds such standards due to natural conditions, the natural concentration is the standard for that constituent. Where the concentration of a certain constituent exceeds such standard due to human-induced contamination, no further contamination by that constituent is allowed and every reasonable effort shall be made to identify, remove or mitigate the source of such contamination and to strive where practical to reduce the level of contamination over time to support drinking water use.

These standards established in West Virginia's Groundwater Protection Act are very similar to Pennsylvania's rulemaking because the minimum standard for restoration of groundwater is the Federal Safe Drinking Water Act which is the same standard the Pennsylvania SDWA standard is derived from. West Virginia also establishes rebuttable presumption similar to Pennsylvania, in which the oil or gas operator has to prove that the water supply pollution or diminution was not caused by drilling of the well by establishing one of the defenses provided in the regulations.

New York
In New York, water supply complaints may be filed via a 24/7 toll-free number. Citizens can also report a violation online. Title 6, Chapter V. Subchapter B. Part 554(b) states, Pollution of the land and/or of surface or ground fresh water resulting from exploration or drilling is prohibited. When pollution occurs, including to water and groundwater, remediation procedures must meet the criteria in Title 6, Chapter IV Subchapter B Subpart 375-1.8. These criteria utilize use-based cleanup standards. When the water is used for drinking water, the standards for drinking water are found in Title 6, Chapter X Subchapter A. Article 2 Part 702 Standards and guidance values for protection of human health and sources of potable water supplies.

Conclusion
Pennsylvania is comparable to the other states in that it requires the restoration of water supplies found to be affected by oil and gas operations. The other states establish minimum standards for these restorations based on Federal Standards; i.e. Safe Drinking Water Act, Clean Water Act, etc. Pennsylvania's standards are more stringent in that the water supply must be restored to the standards established under the Pennsylvania Safe Drinking Water Act (SDWA) (35 P.S. §§ 721.1 – 721.17), or is comparable to the quality of the water that existed prior to pollution if the water quality was better than SDWA standards.

Predrilling or prealteration survey

Section 3218(c) of the 2012 Oil and Gas Act establishes a presumption of liability for an operator who impacts a water supply located within a certain distance from the wellbore and within a certain timeframe. Subsection (d) allows an operator to rebut the presumption by proving that "the pollution existed prior to the drilling, stimulation or alteration activity as determined by a predrilling or prealteration survey…" The onus of conducting a predrill survey on the operators because the Department will require water supplies impacted by oil and gas operations to be restored to SDWA standards or better, based upon the pre-drill water supply survey results. By failing to establish predrill water quality, the operator opens itself up to liability for any failure to meet drinking water standards in any water supply located within the presumption's radius for any substance found in the water supply. The rulemaking sought to refine the process in which water supply surveys are submitted to the Department. The rulemaking allows an operator to submit a copy of all predrill sample results taken as part of a survey to the Department by electronic means. The final rule also allows all sample results pertaining to the oil or gas well of concern to be submitted to the Department by the operator 10 days prior to commencement of drilling of the well.

Colorado

Rule 609 contains the statewide groundwater baseline sampling and monitoring requirements. Rule 609 applies to oil and gas wells, multi-well sites, and dedicated injection wells. An operator may elect to install one or more groundwater monitoring wells to satisfy, in full or in part, the sampling location requirements. Initial baseline samples and subsequent monitoring samples shall be collected from all available water sources, up to a maximum of 4, within a one-half mile radius of a proposed oil and gas well, multi-well site, or dedicated Injection well. If more than 4 available water sources are present within a one-half mile radius of a proposed oil and gas well, multi-well site, or dedicated injection well, the operator shall select the four sampling locations based on the following criteria: Proximity; Type of Water Source; Orientation of sampling locations; multiple identified aquifers available and Condition of Water Source. Prior to spudding, an operator may request an exception from the requirements if water sample locations are not available, accessible or unsuitable within the required half-mile radius. Initial sampling shall be conducted within 12 months prior to setting conductor pipe in a well or the first well on a multi-well site, or commencement of drilling a dedicated injection well. One subsequent sampling event shall be conducted at the initial sample locations between 6 and twelve 12 months, and a second subsequent sampling event shall be conducted between 60 and 72 months following completion of the well or dedicated injection well, or the last well on a multi-well site. Wells that are drilled and abandoned without ever producing hydrocarbons are exempt from subsequent monitoring sampling. The Director may require additional sampling if changes in water quality are identified during subsequent monitoring. Lists of parameters are provided in Rule 609 for initial baseline testing and subsequent sampling events. Within 3 months of collecting the samples, copies of all final laboratory analytical results are to be electronically submitted to the Commission and also sent to the water well owner or landowner. Under Rule 318A.f, The Greater Wattenberg Area in Colorado has a similar but less stringent set of groundwater monitoring rules, with the primary difference being the amount of water samples required pre and post drilling due to the large amount of ground water data already available in the area.

Ohio

Ohio Revised Code Title 15 Chapter 1509.06(A)(8)(b) requires well operators to take pre-drilling water samples of water wells within three hundred feet of the proposed unconventional oil or gas well prior to commencement of drilling within an urbanized area. For non-urban areas, Ohio Title 15 Chapter 1509.06(A)(8)(c) requires well operators to take pre-drilling water samples within 1,500 feet of a proposed horizontal well and disclose the results in the permit application. Ohio Department of Natural Resources, Division of Oil and Gas Resources Management (DOGRM) may require an oil and gas company to sample all domestic wells in a given area. Sampling may be based on hydrology, geology, aquifer characteristics, or any number of other factors. DOGRM requires that a minimum of 12 prescribed parameters be taken as part of pre-drilling water samples. DOGRM will maintain the sampling data. The sampling data will serve as background or historic groundwater quality information. Should the need arise; the background information will be used by the DOGRM Technical Section to conduct hydrologic investigations of domestic water supplies.

West Virginia

West Virginia Law Title 35 Series 4 §35-4-19 provides the owners of record of the surface tract where the oil or gas well is located or an occupant of land within 1,000 feet of the proposed well may request that the operator sample and analyze water from any wells or springs located within 1,000 feet of the proposed well that is actually utilized by such owner or occupant for human consumption, domestic animals, or other general use. If no request is made by property owners, the operator shall sample and analyze water from any one known and existing well or spring within 1,000 feet of the proposed well. If more than one such well or spring exists, the operator shall select for sampling and analysis the one well or spring that, in the operator's judgment, has the highest potential for being influenced by the operator's well work.

If for any reason the operator is unable to sample and to analyze water from any such water wells or springs within 1,000 feet of the operator's proposed well, the West Virginia DEP may require the operator to sample and to analyze, water from one existing water well or spring located between 1,000 and 2,000 feet from the operator's proposed well. At an operator's discretion, any or all water wells or springs within 1,000 feet of the operator's proposed well may be sampled and analyzed. The operator shall give notice to the surface tract owner their request to sample and analyze a well or spring. West Virginia requires a short list of 5 parameters to be tested for predrill samples. Within 30 days after receipt of sample analysis, the operator must provide the results of such sample analysis in writing to the Chief and to any of the entitled water users who may have requested such analysis.

New York

New York requires predrill sampling within 1000 feet of the proposed conventional oil or gas well.

Conclusion

Colorado, Ohio, New York and West Virginia all require operators, to varying degree, to conduct pre-drill sampling of water supplies before drilling can take place. Pennsylvania does not require operators to take predrill water samples, leaving it up to each operator to determine the level of risk they are willing to bear, since failing to establish predrill water quality opens the operator up to liability for any failure to meet drinking water standards in any water supply located within the area of presumption for any substance found to exceed SDWA standards in the water supply.

Area of Review

This rulemaking will require operators to identify oil and gas wells within 1,000 feet of the vertical and horizontal wellbore prior to drilling. The review distance is limited to within 500 feet of the wellbore for vertical oil wells. Additionally, this rulemaking will require operators to monitor a higher-risk subset of the identified wells during hydraulic fracturing activities and plug any wells altered by hydraulic fracturing.

Several states regulating oil and gas activities address the area of review concept with comparatively limited rule language or policies. For example, Nevada rules require that publicly available maps and cross-sections within a 1-mile radius surrounding the well site, which describe the surface and subsurface geology, be referenced for the identification of known or suspected faults.

Colorado
Like Pennsylvania, Colorado is currently targeting 2016 for the development of regulations regarding this concept. The Oil and Gas Commission in that state currently establishes a 1,500-foot buffer area surrounding the well site in its "Horizontal – Statewide Interim Policy." Offset wells within this buffer zone must be assessed.

Ohio
Ohio currently requires mapping of all producing wells and those being drilled within specific distances categorized as a function of drilling depth. The distances between the subject well and the offset wells must be provided. As part of each permit application, a geological risk analysis is performed by the Ohio Department of Natural Resources. An operator may be required to plug or workover an abandoned well depending on the outcome of that analysis.

West Virginia
West Virginia requires that each well permit application for a horizontal well include the identification of all wells within 1,200 feet of the surface location of the new well and within 500 feet of the horizontal section of the wellbore. For proposed horizontal well sites with a depth of 3,000 feet or more that penetrate a coal seam, the operator must identify all wells within 2,400 feet of the surface location of the new well. The 500-foot offset distance from the lateral section of the wellbore also applies for these wells.

Oklahoma
The current regulations in Oklahoma specify that a 5-day notice be provided to all operators within a half-mile of the stimulated well when offset wells are producing from the same formation.

Alaska
Alaska and the province of Alberta more comprehensively address communication risks associated with hydraulic fracturing. In December 2014, Alaska promulgated a regulation related to hydraulic fracturing that required applicants intending to conduct the activity to identify any well penetrations (all well types) within one-half mile of the proposed wellbore trajectory and fracturing interval and provide the sources of information used in identifying such wells. Additionally, Alaska's rule requires operators to submit the location, orientation and geological data of known or suspected faults and fractures that may transect the confining zone, and provide information sufficient to support a determination that any such faults and fractures will not interfere with containment of the hydraulic fracturing fluid. The mechanical condition of each well that may transect the confining zone must also be reported under this rule.

Alberta, Canada
The Energy Resources Conservation Board in Alberta addresses the subject of inter-wellbore communication in Interim Industry Recommended Practice (IRP) 24. This recommended practice was drafted on May 21, 2013 and the industry review period ended on October 23, 2015. Operators are required to manage the risks of communication incidents during hydraulic fracturing between the stimulated wells and surrounding wells. This is accomplished through development of a hydraulic fracturing program consisting of the following elements: a determination of the fracture planning zone, identification of offset wells within the fracture planning zone, an assessment of well integrity for each identified offset well, a risk assessment for each offset well using methodologies prescribed in the IRP, identification of at-risk offset wells, identification and special consideration of wells for potential inclusion in a well control plan and the identification of "energizing gases" used in the fracture-fluid

mixture. The hydraulic fracturing program must be maintained at the subject well for the duration of the operation.

Other Comparisons

The American Petroleum Institute (API), which serves as one of the premier industry organizations involved in the development of standards and recommended practices, finalized API Recommended Practice (RP) 100-1 in October 2015. Within the RP, the area of review concept is addressed in a section covering offset well data. Although API is not a regulatory authority and acknowledges that all government rules and regulations take precedence over its best practices and standards, it is significant that the industry group has released guidance on this matter.

The area of review is termed the Area of Investigation (AOI) in the RP, and it is described as a three-dimensional area of the subsurface where there is the potential for unintended fluid migration associated with the fracturing process. The presence of existing and legacy wells, hydraulic fracturing design, and geologic parameters such as seals and faults are all referenced in the RP. API suggests a risk-based approach inclusive of mitigation strategies such as changing the wellbore path or completion design, intervention at offset wells to address integrity, monitoring offset wells or not drilling the subject well at all in certain circumstances. The concept of "simultaneous operations" is another critical component of the RP and the authors recommend coordination and data compilation to facilitate a better understanding of the risks in any given area of development. Consultation with landowners regarding the location of offset wells is also proposed.

Conclusion

Pennsylvania's final rulemaking contains elements referenced in the Alaska regulation and Alberta's IRP. Strong similarities are also found in the API RP. One notable and anticipated difference is that the area of review in Pennsylvania is considerate of typical well spacing in the state and the difference between expected fracture propagation distances and well drainage areas. Additionally, the Pennsylvania rulemaking clarifies that operators who alter abandoned wells during hydraulic fracturing activities must plug those wells. While other nearby states, including Ohio and West Virginia, do not currently have similar requirements, the Department has determined that these components of the rule are critical to ensure protection of waters of the Commonwealth and does not believe there is any evidence to support that they will affect the industry's ability to remain competitive with operators in other states. This contention is primarily based on the fact that the regulation offers a mechanism for operators to document due diligence consistently ahead of hydraulic fracturing activities.

Control and disposal planning

Pennsylvania requires that oil and gas operations shall prepare and implement site specific Preparedness, Prevention and Contingency (PPC) plans according to §§ 91.34 and 102.5(l) (relating to activities utilizing pollutants; and permit requirements). Additionally, the well operator shall prepare and develop a site specific PPC plan prior to storing, using, or generating regulated substances on a well site from the drilling, alteration, production, plugging or other activity associated with an oil or gas well or transporting those regulated substances to, on or from a well site. Unconventional well operators' PPC plans must describe the containment practices to be utilized and the area of the well site where primary and secondary containment will be employed as required under § 78a.64a (relating to secondary containment). The unconventional well operators' PPC plan must also include a description of the equipment to be kept onsite during drilling and hydraulic fracturing operations that can be utilized to prevent a spill from leaving the well site.

Colorado

In Colorado, the siting of oil and gas locations, which include well pads, pits, and other surface-disturbing activities, is governed by Rule 303.d, which requires operators to submit an Oil & Gas Location Assessment (Form 2A) for COGCC review. Protection of surface and groundwater resources is one of the primary objectives of this review, and special conditions of approval (COAs) and best management practices (BMPs) are required where appropriate. Waste Management Plans are sometime required to be attached to a Form 2A to ensure that exploration and production waste is properly stored, handled, transported, treated, recycled, or disposed to prevent threatened or actual significant adverse environmental impacts to air, water, soil or biological resources. Colorado also allows operators to submit comprehensive drilling plans to identify foreseeable oil and gas activities in a defined geographic area, facilitate discussions about potential impacts, and identify measures to minimize adverse impacts to public health, safety, welfare, and the environment, including wildlife resources, from such activities. A comprehensive drilling plan covers more than one proposed oil and gas location within a geologic basin, but its scope may otherwise be customized by the operator to address specific issues in particular areas. An operator's decisions to initiate and enter into a Comprehensive Drilling Plan are voluntary and may be used in lieu of a Form 2A, provided it contains information substantially equivalent to that which would be required for a Form 2A.

Ohio

Ohio regulations in Chapter 1501:9-2 state an operator submitting an application for a permit to construct a well site is required to submit a comprehensive well site plan. These well site plans have emergency response and PPC plan components in them.

West Virginia

West Virginia does not require PPC plans for oil and gas operation sites.

New York

New York does not require PPC plans for oil and gas operation sites.

Conclusion

Pennsylvania has similar requirements to Ohio. Pennsylvania is more stringent then West Virginia, New York and Colorado, but operators in Colorado may submit a Comprehensive Drilling Plan, which is similar in nature to a PPC plan. While Pennsylvania's regulations may be more stringent than the other states, PPC plans are a tool that protects health, promotes safety and prevents pollution to the environment. Preparedness, Prevention and Contingency planning ultimately saves operators money on remediation costs by avoiding or minimizing impacts to the environment.

Containment

Well sites shall be designed and constructed using secondary containment for regulated substances used or generated at an unconventional well site, including solid wastes and other regulated substances in equipment or vehicles. Secondary containment must be used on the unconventional well site when any equipment that will be used for any phase of drilling, casing, cementing, hydraulic fracturing or flowback operations is brought onto a well site and when regulated substances are brought onto or generated at the well site. Secondary containment open to the atmosphere must have an additional 10% capacity volume of the largest container stored in the area to allow for precipitation. These are statutory requirements found in the 2012 Oil and Gas Act. 58 Pa. C.S. § 3218.2.

Secondary containment at unconventional well sites must have a coefficient of permeability no greater than 1 x 10^{-10} cm/sec and must be compatible with the regulated substance.

The Pennsylvania regulation requires a onetime approval of modular storage structures for temporary storage of fluids at well sites.

The rulemaking requires secondary containment around new, refurbished or replaced produced water fluids tanks, and requires tanks to be protected against vandalism and corrosion.

Colorado

Colorado Rule 906d(1) requires that secondary containment constructed on or after May 1, 2009 on federal land, or on or after April 1, 2009 on other land shall be constructed or installed around all tanks containing oil, condensate, or produced water with greater than 3,500 milligrams per liter (mg/l) total dissolved solids (TDS) and shall be sufficient to contain the contents of the largest single tank and sufficient freeboard to contain precipitation. During drilling and completion activities occurring within a buffer zone of 500 feet from a public surface water supply area, Colorado Rule 317B requires flowback and stimulation fluid tanks be placed on a well pad or in an area with down gradient perimeter berms and that berms or other containment devices be constructed around crude oil, condensate, and produced water storage.

Ohio

Ohio Title 15 Chapter 1501 :9-1-07 states, “All persons engaged in any phase of operation of any well or wells shall conduct such operation or operations in a manner which will not contaminate or pollute the surface of the land, or water on the surface or in the subsurface.” Ohio Title 15 Chapter 1509.22(A) states, “Except when acting in accordance with section 1509.226 of the Revised Code (pertaining to surface applications of brine), no person shall place or cause to be placed in ground water or in or on the land or discharge or cause to be discharged in surface water brine, crude oil, natural gas, or other fluids associated with the exploration , development, well stimulation, production operations, or plugging of oil and gas resources that causes or could reasonably be anticipated to cause damage or injury to public health or safety or the environment.” Ohio Title 15 Chapter 150.22(C)(5) allows for voluntary use of dikes or pits for spill prevention and control.

West Virginia

West Virginia Title 35 § 35-8-18 for Spill and Pollution Prevention and Control Measures; Drilling, Completion, Work-over, and Production Operations section 18.1 states that techniques shall be used on well sites so as to prevent spills of any pollutants to surface waters and ground waters. Title 35 § 35-8-18 Section 18.6 states that secondary containments shall be installed with impermeable basins for tanks used for stored liquids other than freshwater and shall have a capacity of one hundred and ten percent (110%) of the largest tank within a battery.

New York

Title 6 CRR-NY 556.4 (c) states when it is deemed necessary by the Department for the protection of life, health, or property, the department may require any lease or other oil storage tanks to be surrounded by an earthen dike which shall have a capacity of one and one-half times the capacity of the tank or tanks it surrounds.

Conclusion
Pennsylvania is more stringent than the other states in that it is the only one that requires containment on the well site during drilling, casing, cementing, hydraulic fracturing or flowback operations. This is a statutory requirement. Some of the states allude to employing secondary containment with regulatory language stating the operator must prevent pollution, but their regulatory language does not specifically require provisions for the installation of secondary containment on the well pad during well development operations. The other states have, to varying degree, requirements for secondary containment around various fluids tanks (oil, condensate, flowback or produced water), that are similar to Pennsylvania. While Pennsylvania's regulation may be more stringent than the other states, it prevents the numerous small spills and releases during these drilling activities from polluting or threatening to pollute Waters of the Commonwealth, and is ultimately a cheaper mode of operation for operators then remediating the all the spills or releases that would not be contained otherwise.

Tanks used for temporary storage

The rulemaking requires a onetime approval of modular storage structures that exceed 20,000 gallons of capacity used for temporary storage of regulated substances. The Department will maintain a list of approved modular storage structures on its web site. Operators still need to obtain approval for the sitting of modular storage tanks at individual well sites. Operators also need to notify the Department at least 3 business days prior to construction of modular storage structures.

The rulemaking requires operators to take reasonable measures to protect tanks at unconventional well sites used for temporary containment from unauthorized acts of third parties.

Condensate or condensate mixed with other fluids at a concentration greater than 1% by volume may not be stored in open top structures or pit. Aboveground tanks used for storing or separating condensate during well completion shall be monitored and have controls to prevent vapors from exceeding the lower explosive limits of the condensate outside the tank. The tanks used for storing or separating condensate must also be grounded.

Colorado
Colorado has a written policy for modular large volume tanks (MLVTs). This policy was written due to failure of 4 of these structures. MLVTs include any aboveground tank field assembled from multiple uniform factory prepared components used to support synthetic liner which provides primary containment for 5,000 barrels or more of fluids Colorado regulations do not specify the need to take security measures for tanks. MLVTs are typically field assembled on an oil and gas location for temporary use and are dismantled for movement to a different location following their use. This policy allows Operators to store freshwater in MLVTs in support of Oil and Gas Operations. This policy does not allow for exploration and production waste to be stored in MLVTs at this time. Operators must notify the COGCC prior to placing a MLVT into service at an oil and gas location. The MLVT design package must be certified and sealed by a Licensed Professional Engineer stating that the design specifications are adequate to withstand the loads resulting from using the tank. Operators employing MLVTs on their Oil and Gas Locations must comply with the testing and re-inspection requirements and associated written

standard operating procedure. Each Operator must develop a contingency plan/emergency response plan for any MLVT leak or catastrophic failure of the tank integrity and resulting loss of fluid. Colorado Rule 605 does cite industry standards that must be met for oil and condensate tanks.

Ohio

Ohio DNR can cite Chapter 1509.23 as the reason why to require security measures need to be taken for storage facilities on a well site. Chapter 1509.23 states, Rules of the chief of the division of oil and gas resources management may specify practices to be followed in the drilling and treatment of wells, production of oil and gas, and plugging of wells for protection of public health or safety or to prevent damage to natural resources. Ohio administration code 1501:9-9-03 (H) states that during drilling in an urbanized area a temporary fence no less than three (3) feet in height shall be placed to restrict access to the drilling location. The fence shall have "Danger Stay Out" (or similar) posting at no less than one hundred fifty (150) foot intervals along the outside of the fence. All access to the rig, associated drilling equipment and pits must be restricted. The temporary fence shall be maintained until the drilling pits have been removed. Ohio does not have any specific regulations regarding temporary storage of fluids containing condensate.

West Virginia

West Virginia does not have any regulations for employing security measures for tanks used for temporary storage at unconventional well sites. West Virginia does not have any specific regulations regarding temporary storage of fluids containing condensate.

New York

New York does not have any specific regulations regarding temporary storage of fluids containing condensate on a conventional well site.

Conclusion

Colorado's written policy for modular tanks was written out of necessity due to failures of these tanks in the past. Colorado does have standards for condensate tanks and also allows for hydrocarbon skim pits. Ohio, New York and West Virginia do not have regulations regarding modular storage structures or the temporary storage of condensate. Of the four states, only Ohio is similar in that it requires security measures to protect temporary tanks against unauthorized acts of third parties.

The regulations regarding modular storage structures should have minimal impact on industry. Once a particular modular structure obtains prior approval by the Department, it may be used freely by industry. The siting requirement should be able to be accomplished during the site design and engineering phase, which is undertaken for virtually every unconventional oil and gas well site.

There have been instances of vandalism at oil and gas sites that have caused environmental impact in Pennsylvania. The requirement to protect against unauthorized acts of third parties is to help reduce these instances.

Many operators already follow these provisions as part of their normal operations. These regulations should not affect Pennsylvania's ability to compete with the other states.

Tanks used for produced fluids

The rulemaking requires above ground and underground produced fluids tanks to be protected against corrosion. This is a statutory requirement found in the 2012 Oil and Gas Act. 58 Pa.C.S. § 3218.4.

The rulemaking requires operators to take reasonable measures to protect tanks all new, refurbished or replaced tanks at unconventional well sites used for storing brine or other fluids produced during operation of the well from unauthorized acts of third parties.

The rulemaking requires operators to register underground and partially buried tanks within six months of passage of the rulemaking. All newly proposed underground or partially buried tanks must be registered with the Department prior to installation.

Open top storage structures cannot be used to store brine and other fluids produced during operation of the well.

The rulemaking requires tanks used to store produced fluids be inspected on a monthly basis and those inspections documented. Any deficiencies noted need to be fixed and reported to the Department.

Colorado

Colorado Rule 605(c) requires that all pumps, pits, and producing facilities shall be adequately fenced to prevent access by unauthorized persons when the producing site or equipment is easily accessible to the public and poses a physical or health hazard. Colorado Rule 605 does cite industry standards that must be met for oil and condensate tanks and also distance restrictions. Colorado Rule 323 does not allow storage of oil or any other produced liquid hydrocarbon substance in earthen pits or reservoirs (a.k.a. open top structures) except for emergencies. For inventory and inspection purposes, Colorado Rule 911 required operators to submit to the Director no later than December 31, 1995, an inventory identifying production pits, buried or partially buried produced water vessels, blowdown pits, and basic sediment/tank bottom pits that existed on June 30, 1995. For steel, fiberglass, concrete, or other similar produced water vessels that were buried or partially buried and located in sensitive areas prior to December 30, 1997, operators were required to test such vessels for integrity, unless a monitoring or leak detection system was put in place. Operators of steel, fiberglass, concrete or other similar produced water vessels buried or partially buried and located in sensitive areas were required to repair or replace vessels and tanks found to be leaking. Operators shall repair or replace vessels and tanks found to be leaking.

Ohio

Ohio administration code 1501:9-9-05(D) allows for the DNR to require that valves on storage facilities shall be kept secured by locks, bull plugs, or other similar devices in such a manner as to discourage vandalism. When the DNR determines that valves on storage facilities should be secured, they shall notify the owner(s) and include the reason why securing said valves will protect life, health, and property. Under administration code 1501:9-9-05(E), requires an eight-foot fence with barbed wire on top needs to be installed around the wellhead and tank battery/separator and associated production equipment. Also, tank hatch lids in urbanized areas must have a functioning seal and the hatch shall be secured at all times the well owner or his representative is not on-site. Aboveground, open top containers may be used on a well site to store produced fluids.

West Virginia

West Virginia regulations do not specify the need to take security measures for tanks used for produced fluids. West Virginia Title 35 § 35-1-7.6 requires all tanks containing oil or other pollutants shall be visually examined by a competent person as to their condition and need for maintenance on a scheduled periodic basis. West Virginia Code §22-30-4(b) requires registration of all ASTs by July 1, 2015. West Virginia Code §22-30-6(a) requires each regulated aboveground storage tank and its associated secondary containment structure shall be evaluated by a qualified registered professional engineer or a qualified person. West Virginia Code §22-30-15(a)(1-2) states that any owner or operator of an aboveground storage tank shall, upon request of the secretary, furnish information relating to the aboveground storage tanks, their associated equipment and contents and conduct reasonable monitoring or testing.

New York

New York Title 6 CRR-NY 612.2 exempts all aboveground and underground tanks used for petroleum storage at oil production facilities. There are no requirements for corrosion control, security measures, and inspections found in New York regulations for aboveground and underground storage tanks located at oil or gas well sites.

Conclusion

New York and Ohio have no corrosion or inspection requirements for produced fluids tanks. West Virginia requires inspection and maintenance of tanks on a scheduled periodic basis. Colorado requires tanks to meet specific API Standards as identified in their regulations. Pennsylvania's corrosion requirements for produced fluids tanks are a statutory requirement found in the 2012 Oil and Gas Act. 58 Pa.C.S. § 3218.4. In the final rulemaking, the requirement for a third-party, Department certified inspector was removed. This allows operators to train their own personnel, who are routinely at the production locations, to conduct these inspections. They would also be able to identify the location of underground or partially buried produced fluid tanks for their companies, who must provide this information to the Department, eliminating any extra work operators must perform to meet this requirement. Of the other four states, Colorado is the only one that requires the reporting of underground or partially buried storage structures. Colorado is also the only other state that does not allow the use of open top storage structures to store brine and other fluids produced during operation of the well. Pennsylvania's regulations are more stringent for these requirements, but they should not affect Pennsylvania's ability to compete.

Colorado, Ohio and West Virginia all require, to some degree, operators to take security measures to protect produced fluids tanks from unauthorized acts of third parties. There have been instances of vandalism at oil and gas sites that have caused environmental impact in Pennsylvania. The requirement to protect against unauthorized acts of third parties is to help reduce these instances. Pennsylvania is similar to the other states in this aspect.

Pits for temporary storage

The rulemaking allows for the use of pits at conventional well sites for temporary storage of regulated substances to be used or generated at the well site. Pits with a footprint equal to or greater than 3,000 square feet or a volume equal or greater than 125,000 gallons requires Departmental approval. Pits must be lined with a liner that has a coefficient of permeability of no greater than 1×10^{-10} and be at least 30 mills thick. The Department may approve thinner pit liners if they perform the same as 30 mills liners. Liners must be compatible with the regulated substances stored within the pit. The integrity of all pit liner seams of the adjoining sections of liner shall be tested and recorded prior to use. Condensate, whether separated or mixed with other fluids may not be stored in any open top structure or pit. Operators need to electronically notify the Department three days prior to the construction of a pit greater than 300 square feet.

The rulemaking eliminates the use of pits to store produced fluids (brine), eliminates the storage of condensate in pits (or other open top structures) and requires a permit for the use of pits for temporary waste storage at unconventional well sites.

Colorado

Colorado allows the use of pits for the exploration and production of oil and gas. Colorado Rule 902 requires that any accumulation of oil or condensate in a pit shall be removed within twenty-four (24) hours of discovery, unless the pit is specifically permitted for oil or condensate recovery or disposal use. Also, unlined pits shall not be constructed in areas where pathways for communication with ground water or surface water are likely to exist.

Colorado Rule 903 requires that a pit report/permit form must be submitted to the Director for prior approval for production pits, special purpose pits, hydrocarbon pits and multi-well pits containing produced water, drilling fluids, or completion fluids that will be recycled or reused.

Colorado Rule 904 requires the following specifications shall apply to all pits that are required to be lined by rule or by permit condition:

(1) Materials used in lining pits shall be of a synthetic material that is impervious, has high puncture and tear strength, has adequate elongation, and is resistant to deterioration by ultraviolet light, weathering, hydrocarbons, aqueous acids, alkali, fungi or other substances in the produced water.

(2) All pit lining systems shall be designed, constructed, installed, and maintained in accordance with the manufacturers' specifications and good engineering practices.

(3) Field seams must be installed and tested in accordance with manufacturer specifications and good engineering practices. Testing results must be maintained by the operator and provided to the Director upon request.

(4) Liners shall have a minimum thickness of twenty-four (24) mils.

Rule 316C requires operators to give at least 48 hours advance written notice on a form provided by the Commission of intent to install a liner at any facility.

Ohio

Ohio regulation Chapter 1509.22(B)(2)(a) states that on and after January 1, 2014, no person shall store, recycle, treat, process, or dispose of in this state brine or other waste substances associated with the exploration, development, well stimulation, production operations, or plugging of oil and gas resources without an order or a permit issued under this section or section 1509.06 or 1509.21 of the Revised Code or rules adopted under any of those sections. Ohio allows for lined drilling pits for conventional wells under the permits issued under Chapter 1509.06 or 1509.21. Ohio regulation Chapter 1509.22(C)(7) states that no pit or dike shall be used for the temporary storage of brine or other waste substances except for spill prevention and control or as authorized by the chief. Furthermore, Ohio regulation

1509.22(C)(8) states that no pit or dike shall be used for the ultimate disposal of brine or other liquid waste substances.

West Virginia

West Virginia allows the use of pits for the retention of flowback, freshwater and to contain an accumulation of process waste fluids, drill cuttings or any other liquid substance generated in the development of a well. Pits used for conventional well drilling do not require liners. West Virginia code §22-6A-9 requires pits with a capacity of two hundred ten thousand gallons or more must be constructed in accordance with plans designed and certified by a West Virginia registered professional engineer and secure a certificate of approval from the secretary to place, construct, enlarge, alter, repair, remove or abandon the pit. These pits must also incorporate lifelines and perimeter fencing for increased safety. West Virginia Code §22-6A-14 states that pits used for horizontal drilling of wells may not be left open permanently and have to be reclaimed. West Virginia Title 35 Series 4 section 16.4.d. states that all pits and impoundments shall have an impermeable synthetic liner to prevent seepage or leakage, except those pits and impoundments deemed to be suitable to prevent seepage or leakage based on soil analyses from the operator and standards developed and certified by a registered professional engineer and approved by the Office. West Virginia's pit policy requires 60 mills liners for pits used for unconventional drilling. West Virginia Title 35 Series 4 section 16 states that prior to the construction of… pits for any permitted well work, the operator or his contractor shall notify the appropriate oil and gas inspector and allow the opportunity of inspecting and approving the construction and method of reclamation for all proposed areas to be disturbed in siting, drilling, completing or producing the well. In addition, the well operator or his contractor shall notify the appropriate district oil and gas inspector twenty-four (24) hours before actual permitted well work is commenced. Title 35 Series 4 section 21.6.b requires all pits and impoundments with a capacity of greater than 5,000 barrels containing fluid must be inspected every two (2) weeks for the life of the pit or impoundment and within twenty-four (24) hours of a significant rain event, which shall be defined as rainfall of two (2) inches or more in a six (6) hour period.

New York

New York Title 6 CRR NY 554.1(c)(2) allows for brine or salt water may be temporarily stored prior to disposal in any water-tight tank, container or an earthen pit which is under laid by soil such as heavy clay or hardpan. Impounding of brine or salt water in an earthen pit is prohibited where the soil underlying the pit is porous and/or is closely under laid by a gravel, rock or sand stratum unless the pit is lined with watertight material. 6 CRR-NY 556.4 (a) maintains that oil shall not be produced, stored or retained in earthen reservoirs. 6 CRR-NY 556.5 (1) Brine or salt water may be stored prior to disposition in any watertight tank or container including an earthen pit which is under laid by tight soil such as heavy clay or hardpan.

Conclusion

Colorado and New York allow the use of unlined pits upon approval in certain areas where it can be proven the soil can contain the fluids, otherwise liners must be used. West Virginia does not require pit liners for conventional drilling. Ohio requires that pits for temporary storage contain a liner. When a liner is required, Pennsylvania is more stringent, but this requirement is not new to the final rulemaking, and is currently being employed by industry. Pennsylvania does require a prior notice before construction of some pits, but this allows an inspector advance notice of a critical stage in well site development. Of the other four states, West Virginia is the only other state that requires an advance notice for permitted work. Colorado does allow the storage of condensate in a pit, but only if a prior permit is obtained.

Onsite disposal of drill cuttings and residual waste

The rulemaking still allows for disposal of uncontaminated drill cuttings from above the surface casing at conventional and unconventional well sites using unlined pits and land application. Conventional operators may also dispose of the solid fraction of residual waste generated by the drilling of an oil or gas well that is located on the well site in a pit or by land application, if the residual waste meets certain criteria. If using a pit for disposal of residual waste, the conventional well operator needs a soil scientist or other similarly trained person using accepted and documented scientific methods to determine and document that the pit bottom is at least 20 inches above the seasonal high groundwater table prior to using the pit.

Unconventional well operators must obtain a residual waste disposal permit from the Department prior to disposing of residual waste at the well site in a pit or by land application.

All operators need to electronically notify the Department at least 3 business days before disposing of any drill cuttings or residual waste via a pit or land application. Additionally, the operator must also notify the property owner of the location of the disposal area within 10 days after disposing of the drill cuttings or residual waste.

Colorado

Rule 1003(d) allows for dry drill cuttings to be disposed of onsite. Drill cuttings must meet the standards listed in table 910-1 of the 900 series of the Rules. All drilling fluids shall be disposed of in accordance with the 900 Series rules and not in the pit. Colorado does not require a qualified person to determine high seasonal groundwater table prior to construction of a reserve pit. Colorado does not require notification from operators prior to drilling pit closure. Colorado allows private land application as a beneficial soil amendment to native soil. Operators shall obtain written authorization from the surface owner prior to private land application of drill cuttings. Rule 907a(3) promotes beneficial use, reuse, and recycling of exploration and production waste. A waste management plan submitted via Sundry Notice Form 4 is required prior to private land application. Operators shall obtain written authorization from the surface owner prior to private land application of drill cuttings.

Ohio

Regulation 1509.22(C)(8) says no pit or dike shall be used for the ultimate disposal of brine or other liquid waste substances. 1509.22(C)(3) states muds, cuttings, and other waste substances shall not be disposed of in violation of this chapter or any rule adopted under it. There are no rules allowing for the onsite disposal of cuttings.

West Virginia

Conventional well drillers can manage drill cutting onsite as per an approved permit. Title §22-6A-8 allows for drill cuttings and associated drilling mud from unconventional wells to be managed on-site in a manner approved by the secretary. Surface owner consent is required. Operators must submit a fluids/cuttings disposal & reclamation plan. Only conventional wells drill cuttings may be buried in a pit upon approval by the WV DEP. West Virginia does not require notification from operators prior to drilling pit closure.

Conclusion

Most of the regulations in this section of the final rulemaking are the same as they currently are. Ohio does not allow for the onsite disposal of drill cuttings, and West Virginia only allows for the disposal of conventional drill cutting. The final regulations do include the requirement for operator notification to the Department 3 business days before disposal and landowner notification within 10 days after disposal. This particular requirement is more stringent than the other four states. This allows an inspector advance notice of a critical stage in well site development, and provides a landowner to know exactly where on their property the disposal took place. This requirement should not affect Pennsylvania's ability to compete because, overall, Pennsylvania is less stringent regarding the onsite disposal of drill cutting and residual waste.

Onsite Processing

The rulemaking allows operators to request approval from the Department to process fluids generated at a well site for beneficial reuse used to develop, drill or stimulate a well at the well site or another well site. If an operator is only mixing fluids with freshwater; aerating the fluids, or filtering solids from the fluids for beneficial reuse, they do not need to seek approval prior to processing the fluids. Operators may request to process drill cuttings only at the well site where those drill cuttings were generated by submitting a request to the Department for approval. These requests will be submitted on forms provided by the Department. If the Department approves an operator's particular method for processing fluids, that method will be deemed already approved at subsequent well sites provided the operator electronically notifies the Department of location of the well site where the processing will occur 3 business days prior to the beginning of processing operations. Sludges, filter cake or other solid waste remaining after the processing or handling of fluids under, including solid waste mixed with drill cuttings, must be characterized before the solid waste leaves the well site. Operators processing fluids or drill cuttings on a well site need to develop an action plan specifying the procedures for monitoring and responding to radioactive materials produced by the treatment process.

Colorado

Rule 907 allows operators to propose plans for managing exploration and production waste through beneficial use, reuse, and recycling by submitting a written management plan to the Director for approval on a Sundry Notice, Form 4, if applicable. Such plans shall describe, at a minimum, the type(s) of waste, the proposed use of the waste, method of waste treatment, product quality assurance, and shall include a copy of any certification or authorization that may be required by other laws and regulations. Produced water may be reused for enhanced recovery, drilling, and other approved uses. Drilling pit contents may be recycled to another drilling pit for reuse consistent with pit permitting and reporting requirements under Rule 903. Rule 907A specifies that certain wastes generated by oil and gas-related activities are non-exploration and production wastes and are not exempt from regulation as solid or hazardous wastes. These non-exploration and production wastes need to be properly identified and disposed of in accordance with state and federal regulations.

Ohio

Regulation 1509.06 requires an application for a permit to be filed with the Division of Oil & Gas Resources Management in order to drill a new well, drill an existing well deeper, reopen a well, convert a well to any use other than its original purpose, or plug back a well to a different source of supply, including associated production operations. Production operations includes the equipment and facilities at a well pad or other location that are used for the transportation, handling, recycling, temporary storage, management, processing, or treatment of any equipment, material, and by-products or other substances from an operation at a well pad that may be used or reused at the same or another operation at a well pad or that will be disposed of in accordance with applicable laws and rules adopted under them. Onsite processing of solid wastes is included in this requirement.

West Virginia
Title § 22-6A-2(a)(7) states, practices involving reuse of water in the fracturing and stimulating of horizontal wells should be considered and encouraged by the department, as appropriate.

New York
New York does not have regulations for onsite processing of oil and gas waste.

Conclusion
Pennsylvania is similar to Colorado and Ohio in that both the other states require submittal of a plan or permit application that must be approved before onsite processing may occur. West Virginia's regulations state they will consider practices that involve the reuse of water in the fracturing and stimulating horizontal wells. New York does not have any regulations for onsite processing of oil and gas waste. Since this practice is generally used by the unconventional industry and New York currently has a moratorium on the drilling of unconventional wells, this will not affect Pennsylvania's ability to be competitive.

Impoundments

The final rulemaking also establishes embankment construction standards, construction standards and restoration requirements for well development impoundments. Well development impoundments are synthetically lined earthen structures designed to hold surface water, fresh groundwater, and other fluids approved by the Department for the drilling and development of oil and gas wells. Well development impoundments do not reach the height and volume thresholds to be regulated by a dam permit under 25 Pa.Code § 105.3. The rulemaking no longer has provisions for centralized wastewater impoundments under the jurisdiction of the Oil and Gas Program. Pennsylvania still allows for the use of centralized wastewater impoundments but they need to be permitted under existing rules and regulations under the Department's Waste Management Program. Existing centralized wastewater impoundments under the jurisdiction of the Oil and Gas Program must be either permitted by the Waste Management Program or be closed and reclaimed. Operators choosing the latter need to electronically submit a closure plan to the Department 6 months from the effective date of this rulemaking for its closure within 3 years from the effective date of the rulemaking.

Colorado
In Colorado, a pit is any natural or man-made depression in the ground used for oil or gas exploration or production purposes. Colorado allows for fresh water pits among the many other types of pits. Produced water, recycled E&P waste, or flowback fluids are not allowed in fresh water storage pits. Fresh water pits within the Exception Zone (500 feet from a Building Unit) shall require prior approval of a Form 15, Earthen Pit Report/Permit. In the Buffer Zone (1,000 feet from a Building Unit), the installation of fresh water pits shall be reported within 30-days of pit construction. Otherwise, fresh water pits do not need to be reported. Fresh water storage pits within the Buffer Zone Setback shall include emergency escape provisions for inadvertent human access. Fresh water pits do not need to be lined unless in an area where pathways for communication with ground water or surface water is likely to exist.

Ohio
Ohio regulations permit the use of lined impoundments that hold freshwater for drilling. DNR has a policy/procedure directive that provides minimum required standards for the construction and operation of impoundments.

West Virginia
For centralized impoundments, West Virginia code §22-6A-9(b) states, "It is unlawful for any person to place, construct, enlarge, alter, repair, remove or abandon any freshwater impoundment or pit with capacity of two hundred ten thousand gallons or more used in association with any horizontal well operation until he or she has first secured from the secretary a certificate of approval." The initial term of a certificate of approval issued is one year. Existing certificates of approval shall be extended for one year upon receipt of the annual registration fee, and the applicant must either have on file with or submit to the WV DEP an approved, up-to-date inspection report, a monitoring and emergency action plan, and a maintenance plan. There must also be no outstanding violation of the requirements of the certificate of approval. West Virginia rules §35-4-16.4 and §35-4-21 (as they relate to construction standards for freshwater impoundments), provide similar protective provisions as those contained in the Commonwealth's proposal for well development impoundments, but do not contain as many of the prescriptive measures of Pennsylvania's regulation.

New York
New York Title 6 CRR-NY 608.3 does not require a dam permit for freshwater impoundments if the dam has a height less than 15 feet, and a maximum impoundment capacity less than three million gallons; or if the dam has a height equal to or less than six feet, regardless of its maximum impoundment capacity, or a dam with a maximum impoundment capacity equal to or less than one million gallons, regardless of its height. Conventional well drillers have no need to build a fresh water impoundment that would exceed these thresholds.

Conclusion
All four other states allow for the use of well development impoundments. Colorado regulations state freshwater impoundments shall require prior approval if sited in certain zones, otherwise they do not need to be reported. A liner is only required in areas where communication with ground or surface water may exist. Ohio allows the use of freshwater impoundments, if certain construction standards are met. In West Virginia, freshwater impoundments are allowed, and if they exceed 200,000 gallons, a certificate of approval must be obtained before their use. New York allows the use of freshwater impoundments if they meet certain criteria. Since these impoundments are generally used by the unconventional industry and New York currently has a moratorium on the drilling of unconventional wells, this gives Pennsylvania a competitive advantage over New York. Overall, the final rule's standards are similar to provisions in the other states; therefore, the final rule is less burdensome and equally as protective.

Site Restoration

Section 3216 of 58 Pa.C.S. §§ 3201-3274 (2012 Oil and Gas Act) requires an operator to restore the surface area disturbed during the construction of the well site not needed for production operations of the well(s) and storm water management best management practices of the well site. Section 3216 of the 2012 Oil and Gas Act requires the well owner or operator to restore the well site, remove or fill all pits used to contain produced fluids or industrial wastes and remove all drilling supplies and equipment not needed for production within 9 months after completion of drilling of a well. Well sites also need to be restored 9 within months after the plugging of a well. The 9-month restoration period may be extended by the Department for an additional period of up to 2 years, provided the operator meet certain criteria required in Section 3216 of the 2012 Oil and Gas Act.

The rulemaking allows for the 9-month restoration deadline to apply when the last permitted well is drilled or all well permits are expired for a pad permitted for multiple oil or gas wells. The rulemaking provides for areas of a well pad that do not need to be restored so operators may safely operate the well(s). The rulemaking extends the amount of time allowed to restore a well site that did not have a well drilled from 30 days to 9 months. The rulemaking includes prescriptive measures for well site restoration that are in accordance with 25 Pa.Code Chapter 102.

The rulemaking also coordinates site restoration requirements of well development impoundments, borrow pits and well development pipelines to follow the same restoration schedule as the last well site they serviced.

The rulemaking allows the operator to not scale back the size of the well pad with land owner consent and installation of post construction stormwater BMPs.

Colorado

Rule 1003 pertains to interim restoration, which is the equivalent to Pennsylvania's requirement for restoration of a well site after well development activities. Rule 1003 requires debris, waste materials, equipment associated with the drilling, re-entry, or completion operations to be removed. All pits, cellars, rat holes, and other bore holes unnecessary for further lease operations, excluding the drilling pit, need to be backfilled as soon as possible after the drilling rig is released. All disturbed areas affected by drilling or subsequent operations, except areas reasonably needed for production operations or for subsequent drilling operations to be commenced within twelve (12) months, shall be reclaimed as early and as nearly as practicable to their original condition or their final land use as designated by the surface owner. Areas reasonably needed for production operations or for subsequent drilling operations to be commenced within twelve (12) months shall be compacted, covered, paved, or otherwise stabilized and maintained in such a way as to minimize dust and erosion to the extent practicable. All areas compacted by drilling and subsequent oil and gas operations which are no longer needed following completion of such operations shall be cross-ripped to a depth of eighteen (18) inches unless and to the extent bed rock is encountered at a shallower depth. On crop land or within the 100-year floodplain, closing and reclamation of drilling pits must occur within three (3) months after drilling and completion activities conclude. On non-crop land, closure and reclamation of drilling pits must occur no later than six (6) months after drilling and completion activities conclude, weather permitting. Operators need to implement and maintain post construction stormwater BMPs at all oil and gas locations. The operator needs to submit a form to the Commission describing the interim reclamation procedures and any associated mitigation measures performed.

Rule 1004 pertains to the final reclamation of well sites and associated production facilities. Upon the plugging and abandonment of a well, all pits, mouse and rat holes and cellars need to be backfilled. All debris, abandoned gathering line risers and flow line risers, and surface equipment must be removed within three (3) months of plugging a well. All access roads to plugged and abandoned wells and associated production facilities shall be closed, graded and re-contoured. Culverts and any other obstructions that were part of the access road(s) shall be removed. Well locations, access roads and associated facilities shall be reclaimed. All such reclamation work shall be completed within three (3) months on crop land and twelve (12) months on non-crop land after plugging a well or final closure of associated production facilities. The Director may grant an extension where unusual circumstances are encountered. The operator needs to submit a form to the Commission describing the final reclamation procedures.

At the surface owner’s request, the Commission may waive some of the reclamation requirements if the operator can demonstrate to the Director's or the Commission's satisfaction both that compliance with such rules is not necessary to protect the public health, safety and welfare, including prevention of significant adverse environmental impacts, and that the operator has entered into an agreement with the surface owner regarding topsoil protection and reclamation of the land.

Ohio

Regulation 1509.072 requires the owner of the conventional or unconventional well to restore the land surface within the area disturbed in siting, drilling, completing, and producing the well. Within fourteen days after the date upon which the drilling of a well is completed to total depth in an urbanized area and within two months after the date upon which the drilling of a well is completed in all other areas, the well owner has to fill all the pits and remove all drilling supplies and drilling equipment. Unless the chief of the division of oil and gas resources management approves a longer time period, within three months after the date upon which the surface drilling of a well is commenced in an urbanized area and within six months after the date upon which the surface drilling of a well is commenced in all other areas, the well owner must grade or terrace and plant, seed, or sod the area disturbed that is not required in production of the well where necessary to bind the soil and prevent substantial erosion and sedimentation.

Regulation 1509.072 requires within three months after an oil or gas well is plugged in an urbanized area and within six months after an oil or gas well is plugged in all other areas, or after the plugging of a dry hole, unless the chief approves a longer time period, the well owner will remove all production and storage structures, supplies, and equipment, and any oil, salt water, and debris, and fill any remaining excavations. Within that period the well owner needs to grade or terrace and plant, seed, or sod the area disturbed where necessary to bind the soil and prevent substantial erosion and sedimentation.

The well owner shall be released from responsibility to perform any or all restoration requirements of this section on any part or all of the area disturbed upon the filing of a request for a waiver with and obtaining the written approval of the chief, which request shall be signed by the surface land owner to certify the approval of the surface land owner of the release sought. The chief shall approve the request unless the chief finds upon inspection that the waiver would be likely to result in substantial damage to adjoining property, substantial contamination of surface or underground water, or substantial erosion or sedimentation.

The chief, by order, may shorten the time periods provided for restoration if failure to shorten the periods would be likely to result in damage to public health or the waters or natural resources of the state.

The chief, upon written application by a well owner showing reasonable cause, may extend the period within which restoration shall be completed, but not to exceed a further six-month period, except under extraordinarily adverse weather conditions or when essential equipment, fuel, or labor is unavailable to the well owner. If the chief refuses to approve a request for waiver or extension, the chief shall do so by order.

West Virginia
West Virginia Code §22-6-30 contains the site restoration requirements for conventional wells. Within six months after the completion of the drilling process, the operator must fill all the pits that are not needed for production purposes and remove all concrete bases, drilling supplies and drilling equipment. The operator must grade or terrace and plant, seed or sod the area disturbed that is not required in production of the well where necessary to bind the soil and prevent substantial erosion and sedimentation.

West Virginia Code §22-6-30 requires within six months after a conventional well is plugged, or after the plugging of a dry hole, the operator shall remove all production and storage structures, supplies and equipment, and any oil, salt water and debris, and fill any remaining excavations. The operator must grade or terrace and plant, seed or sod the area disturbed where necessary to bind the soil and prevent substantial erosion and sedimentation.

The director may, upon written application by an operator showing reasonable cause, extend the period within which reclamation shall be completed, but not to exceed a further six-month period. If the director refuses to approve a request for extension, the refusal shall be by order.

West Virginia Code §22-6A-14 contains the site restoration requirements for horizontal wells. Within six months after a horizontal well is drilled and completed on a well pad designed for a single horizontal well, the operator must fill all the pits that are not needed for production purposes and remove all concrete bases, drilling supplies and drilling equipment. The operator must grade or terrace and plant, seed or sod the area disturbed that is not required in production of the well where necessary to bind the soil and prevent substantial erosion and sedimentation.

For well pads designed to contain multiple horizontal wells, partial reclamation shall begin upon completion of the construction of the well pad. The term partial reclamation means grading or terracing and planting, or seeding the area disturbed that is not required in drilling, completing or producing any of the horizontal wells on the well pad in accordance with the erosion and sediment control plan. This partial reclamation satisfies the reclamation requirements for a maximum of twenty-four months between the drilling of horizontal wells on a well pad designed to contain multiple horizontal wells. The maximum aggregate period in which partial reclamation satisfies the reclamation requirements is five years from completion of the construction of the well pad. Within six months after the completion of the final horizontal well on the pad or the expiration of the five-year maximum aggregate partial reclamation period, whichever occurs first, the operator shall complete final reclamation of the well pad.

The director may, upon written application by an operator showing reasonable cause, extend the period within which reclamation shall be completed, but not to exceed a further six-month period. If the director refuses to approve a request for extension, the refusal shall be by order.

Within six months after a horizontal well is plugged or after the plugging of a dry hole, the operator shall remove all production and storage structures, supplies and equipment and any oil, salt water and debris and fill any remaining excavations. Within that six-month period, the operator shall grade or terrace and plant, seed or sod the area disturbed where necessary to bind the soil and prevent substantial erosion and sedimentation.

Within six months upon expiration of the impoundment certificate of approval, the operator must fill all impoundments and reclaim the site in accordance with the approved erosion and sediment control plan. An agreement between the operator and the surface owner allowing the impoundment to remain open for the use and benefit of the surface owner will waive the impoundment restoration requirement.

If the impoundment certificate of approval is revoked by the secretary, the operator must fill all impoundments and reclaim the site in accordance with the approved erosion and sediment control plan within sixty days,

New York

New York well permits require that land impacted by drilling be properly reclaimed for productive use. New York Title 6 CRR-NY 555.5 requires as a part of the plugging and abandonment operation, the owner or operator shall fill with earth any pit or other excavation, including any rat hole or mouse hole, which has been created to facilitate the drilling or production of the well. In addition, a reasonable effort to smooth the surface adjacent to the well and filled pit or excavation so as to place the surface in a condition similar to the adjacent terrain and without undue elevation shall be made. If it can be demonstrated to the satisfaction of the department that no hazard will result and the landowner has signed an appropriate release, these surface restoration requirements will be waived. Within 30 days after the plugging of any well, a plugging report shall be filed with the department by the owner or operator or person responsible for the plugging operation.

Conclusion

All four states require restoration of well sites. Colorado requires that interim restoration occur within 3 or 6 months, depending on where the site is located, and after drilling and completion activities conclude. An extension may be granted where unusual circumstances are encountered. Ohio required the filling of pits and removal of drilling supplies and equipment with 14 days in urban areas and within two months in other locations. The operator must then stabilize the site to prevent erosion and sedimentation with three months in urban areas and within six months in other locations. An extension of up to six months may be granted in certain situations. West Virginia requires operators to stabilize the site and remove all drilling supplies and equipment within 6 months after completion of the drilling process. An extension of up to 6 months may be granted in certain situations. On pads designed to contain multiple horizontal well heads, this partial reclamation also satisfies reclamation requirements for a maximum of 24 months between the drilling of horizontal wells on that well pad. Pennsylvania requires restoration within nine months after the completion of drilling and allows for up to a two-year extension. Overall, the final rulemaking in this section is less burdensome, giving Pennsylvania a completive advantage.

Spill Reporting and Remediation

The rulemaking broadens the scope of the spill reporting requirements for spills or releases of regulated substances on or adjacent to well sites and access roads. The final-form rulemaking requires any spill or release of a regulated substance causing or threatening pollution of the waters of the Commonwealth or a spill or release of 5 gallons or more of a regulated substance over a 24-hour period that is not completely contained by secondary containment to be reported to the Department. These unauthorized releases must be reported to the Department in the manor required by 25 Pa.Code § 91.33 as soon as practicable, but no later than 2 hours after discovering the spill or release. To the extent known, specific information is to be provided to the Department while reporting the spill or release. Interim corrective actions are also to be taken to prevent impacts to waters of the Commonwealth, downstream users and property. The operator or responsible person must identify and sample polluted water supplies and water supplies that have the potential to be polluted. Sample results must be submitted to the Department within 5 days.

Remediation of an area polluted by a spill or release is required. Spills or releases to the ground of less than 42 gallons at a well site that do not pollute or threaten to pollute waters of the Commonwealth can be remediated by removing the soil visibly impacted by the spill or release and properly managing the impacted soil in accordance with the Department's waste management regulations. For spills or releases to the ground 42 gallons or more or that pollute or threaten to pollute waters of the Commonwealth, the operator or responsible person must demonstrate attainment of one or more of the standards established by Pennsylvania's Land Recycling and Environmental Remediation Standards Act (Act 2) and 25 Pa.Code Chapter 250

Colorado

Rule 906 states, Operators shall, immediately upon discovery, control and contain all spills/releases of exploration and production waste or produced fluids to protect the environment, public health, safety, and welfare, and wildlife resources. Operators shall investigate, clean up, and document impacts resulting from spills/releases as soon as practicable. The Director may require additional activities to prevent or mitigate threatened or actual significant adverse environmental impacts on any air, water, soil or biological resource, or to the extent necessary to ensure compliance with the concentration levels in Table 910-1 of the 900 series of the Rules, with consideration to Colorado Water Quality Control Commission ground water standards and classifications.

Operators shall report, as soon as practicable, but no more than twenty-four (24) hours after discovery a spill or release of exploration and production waste or produced fluids that meet any of the following criteria:

- A spills/release of any size that impacts or threatens to impact any waters of the state, a residence or occupied structure, livestock, or public byway;
- A spill/release in which one (1) barrel or more of exploration and production waste or produced fluids is spilled or released outside of berms or other secondary containment;
- A spill/release of 5 barrels or more regardless of whether the spill/release is completely contained within berms or other secondary containment.

The notification must verbally or in writing. The initial report to the Commission shall include, at a minimum, the location of the spill/release and any information available to the Operator about the type and volume of waste involved. A spill/release of any size which impact or threaten to impact any surface water supply area shall be reported to the Commission and to the Environmental Release/Incident Report Hotline (1-877-518-5608). Spills and releases that impact or threaten a surface water intake shall be verbally reported to the emergency contact for that facility immediately after discovery. Also, within 24 hours the operator will provide notification to the local government and to the surface owner. Additionally, chemical spills and releases shall be reported in accordance with applicable state and federal laws.

Rule 909 details the site investigation and remediation requirements. Operators shall complete a sensitive area determination. Sampling and analysis of soil and ground water shall be conducted to determine the horizontal and vertical extent of any soil and water contamination in excess of the concentrations in Table 910-1. Operators shall prepare and submit for prior Director approval, a Site Investigation and Remediation Work plan, Form 27. Remediation shall be performed in a manner to mitigate, remove, or reduce contamination that exceeds the concentrations in Table 910-1 in order to ensure protection of public health, safety, and welfare, and to prevent and mitigate significant adverse environmental impacts. Soil that does not meet concentrations in Table 910-1 shall be remediated. Ground water that does not meet concentrations in Table 910-1 shall be remediated in accordance with a Site Investigation and Remediation Work plan, Form 27. Remediation sites shall be reclaimed. Remediation and reclamation shall be complete upon compliance with the concentrations in Table 910-1, or upon compliance with an approved work plan. Within 30 days after conclusion of site remediation and reclamation activities operators shall provide the following notification of completion. Financial assurance (bond) required by Rule 706 may be held by the Director until the required remediation of soil and/or ground water impacts is completed in accordance with the approved work plan, or until cleanup goals are met.

Ohio

Ohio does not have a requirement for the reporting of spills or releases on a well site. If water is impacted, Ohio Revised Code 3745.50 requires that companies report spills or releases involving a petroleum product (diesel fuel, gasoline, hydraulic fluid, etc.) to local, state and/or federal emergency authorities, if the spill/release exceeds reportable quantities. The reportable quantities are any amount of petroleum that causes a film or sheen on a waterway; or any spill or release to the environment (not contained on the spiller's property) of 25 gallons or more. Ohio EPA is to be notified of these spills.

Ohio requires the spill or release impacted area on a well site to be remediated to the conditions that existed prior to the spill or release event. Background samples are used to determine attainment of preexisting conditions.

West Virginia

Title 35 Series 1 Section 3.1 requires the owner or operator or person in charge of a facility from which a reportable discharge occurs shall notify the Office of Oil and Gas by calling 1-800-642-3074 immediately; but in no case, later than twenty-four (24) hours after becoming aware of the discharge. A reportable discharge on an oil or gas well site is defined as any discharge which would be reportable pursuant to section 311(b) of the Federal Water Pollution Control Act Amendment of 1972, as amended by the Clean Water Act of 1977, 33 U.S.C. 1321, and the regulations promulgated thereunder or any pit failure which results in a discharge to any surface water of the state. The person who notifies the office of a reportable discharge shall report the type of substance and the estimated quantity discharged, if known; the location of the discharge; actions the person reporting the discharge proposed to take to contain, clean-up and remove the substance, if any, and any other information concerning the discharge which the office may request at the time of notification. A written verification of such notification shall be submitted upon request of the office. The owner or operator of a facility from which a reportable discharge has occurred, or any person responsible for causing such discharge, shall attempt to stop the discharge and shall take reasonable measures to contain, clean-up and remove the discharge, to the extent he is capable of doing so.

West Virginia requires the spill or release impacted area on a well site to be remediated to the conditions that existed prior to the spill or release event. Background samples are used to determine attainment of preexisting conditions.

Conclusion
Colorado, Ohio and West Virginia all require notification of spills, either within the same day or within 24 hours. This final rulemaking requires that unauthorized releases threatening water must be reported to the Department in the manor required by § 91.33 as soon as practicable, but no later than 2 hours after discovering the spill or release. This is more stringent than the other states.

Colorado, Ohio and West Virginia all require remediation of an area polluted by a spill or release. Colorado requires operators to sample polluted areas for contamination in excess of the concentrations found in their Table 910-1, prepare and submit an Operator's Remediation Work Plan (Form 27), and then remediate the area to contamination levels in compliance with Table 910-1. Ohio and West Virginia both require polluted areas to be remediated to prior conditions through the use of background samples.

This final rulemaking is designed to allow operators to appropriately address relatively small spills and releases with a minimum of procedural hurdles or cost. It is also the intention of this final rulemaking to codify much of the policies addressed in the document, Addressing Spills and Releases at Oil & Gas Well Sites or Access Roads, Document No. 800-5000-001, which is currently how spills and releases are handled.

Colorado, Ohio and West Virginia all require remediation to be successfully achieved by meeting certain concentration levels proven through the use of sampling, which is similar to Pennsylvania. The Department acknowledges that parts of this section of the final rulemaking are more stringent then these other states, but the choice of how to approach a remedial situation under Act 2 is left up to the operator. The added benefit is that the operator is granted a relief of liability upon successfully achieving Act 2 standards, as is the landowner of where the spill took place.

Pipelines

This rulemaking contains three new sections addressing pipelines associated with oil and gas activities. The first section pertains to gathering pipelines that transport oil, liquid hydrocarbons or natural gas from unconventional wells to intrastate or interstate transmission pipelines. The second section addresses horizontal directional drilling activities associated with the construction of oil and gas pipelines. The third section concerns well development pipelines that transport materials or waste associated with the drilling or hydraulic fracturing of a well. All three of these sections pertain to environmental protection provisions associated with the earth disturbance activities staging of materials and potential impact to Waters of the Commonwealth.

Colorado, Ohio and West Virginia
Colorado Ohio and West Virginia have regulations that address the construction of oil and gas pipelines. These regulations, however, are limited in regards to requiring additional environmental protections during earthmoving and HDD activities for gathering lines.

Conclusion
In contrast, Pennsylvania's pipeline requirements are more stringent than requirements in Ohio, West Virginia and Texas, as well as the requirements for other pipelines in the Commonwealth. The proposed requirements are tailored specifically for the unique nature of oil and gas pipeline construction in Pennsylvania. For example, Pennsylvania has more water resources than other states and oil and gas

pipelines have the potential to impact these waters. For that reason, the pipeline requirements include construction and installation requirements for gathering pipelines; planning, notification, construction and monitoring requirements for horizontal directional drilling; and installation, flagging, pressure testing, inspection and removal requirements for temporary pipelines. These requirements should not affect Pennsylvania's competitive advantage because the gathering pipelines are necessary to get the natural gas to market.

Water Management Plans

Section § 3211(m) of the 2012 Oil and Gas Act establishes the requirement for a water management plan approved by the Department for the drilling or hydraulic fracture stimulation of any natural gas well completed in an unconventional gas formation. The rulemaking codifies the additional requirements pertaining to water management plans and adds additional provisions for water management plans as authorized by the Oil and Gas Act of 2012. Some of these additional provisions include:

- A water purveyor that has a water allocation permit or order confirmation pursuant to the Water Rights Act (32 P.S. §§ 631 – 641), or a Safe Drinking Water permit pursuant to the Safe Drinking Water Act (35 P.S. §§ 721.1 – 721.17), is not required to apply for a water management plan.
- Water withdrawals under a water management plan must ensure the protection of groundwater resources including nearby water wells.
- Submission of surface water withdrawal intake designs, site layout and a description of the measures to be taken to prevent the movement of invasive, harmful or nuisance species from one site to another.
- Submission of groundwater report containing information for withdrawal wells construction plans, hydraulic characteristics of the aquifer and proper water well abandonment.
- Submission of a reuse plan for fluids for hydraulic fracturing of wells or proof of a wastewater source reduction strategy.
- Proof of consultation with the Pennsylvania National Heritage Program.
- Proof of notification to municipalities and counties where the proposed water source is located.
- Signage requirements for water withdrawal stations.
- Withdrawal metering and stream measuring requirements.
- Reporting and record keeping r requirements.

Colorado

Colorado does not require Water Management Plans for the allocation of water for the drilling or hydraulic fracturing of oil and gas wells targeting unconventional formations.

Ohio

Ohio Code Chapter 1521.16 states, any person who owns a facility that has the capacity to withdraw waters of the state in an amount greater than one hundred thousand gallons per day from all sources shall register the facility. Any person who owns a registered facility shall file a report annually with the chief listing the amount of water withdrawn per day by the facility, the return flow per day, and any other information the chief may require by rule.

West Virginia

West Virginia Code 22-6A-7 (e) Requires the submission of a Water Management Plan with the well permit application, if the drilling, fracturing or stimulating of the horizontal well requires the use of water obtained by withdrawals from waters of West Virginia in amounts that exceed two hundred ten thousand gallons during any thirty-day period. The scope of a Water Management Plan may be on an individual well basis or on a watershed basis. West Virginia requires the following information to be provided as part of their Water Management Plan:

- The type of water source (i.e. surface or groundwater), the county of each source and the latitude and longitude of each anticipated withdrawal location;
- The anticipated volume of each water withdrawal;
- The anticipated months when water withdrawals will be made;
- The planned management and disposition of wastewater after completion from fracturing, re-fracturing, stimulation and production activities;
- A listing of the anticipated additives that may be used in water utilized for fracturing or stimulating the well. Upon well completion, a listing of the additives that were actually used in the fracturing or stimulating of the well shall be submitted to the WV DEP;
- For all surface water withdrawals, identification of the designated and existing water uses; identification of public water intakes within one mile downstream; provide methods to minimize adverse impact to aquatic life and instream flow monitoring.

Conclusion

Since Water Management Plans are only required for unconventional drilling, New York was not included since they maintain a moratorium on high volume hydraulic fracturing and no unconventional drilling is taking place. Pennsylvania enjoys a clear competitive advantage with New York.

Colorado does not require a Water Management Plan for unconventional well drilling. Ohio does not have regulations specifically addressing Water Management Plans as they relate to oil and gas activities. In Ohio, any facility that has the capacity to withdraw waters of the state in an amount greater than 100,000 gallons per day must be registered and submit an annual report of their daily withdraws. West Virginia requires the submittal of a Water Management Plan with a well permit application if the fracturing or stimulation of the well requires the use of water obtained by withdrawals from waters of West Virginia in amounts that exceed two hundred ten thousand gallons during any thirty-day period. This would include virtually every unconventional horizontal well.

Pennsylvania has similar requirements to those of West Virginia but has more stringent requirements then the regulations found in Colorado and Ohio. The Department feels that by making WMP requirements consistent statewide, operators will have more certainty regarding the requirements versus other states with river basin commissions that do not have the same level of consistency.

Brine Road Spreading/Deicing,

The rulemaking allows for the use of brine from conventional wells to be spread on unpaved roads for dust control and road stabilization. The rulemaking also allows for the use of brine from conventional wells for pre-wetting, anti-icing and de-icing on paved and tar and chipped roads to address winter driving conditions. These activities shall only be conducted under a plan that must be approved annually by the Department. 24-hour notification must be provided to the Department prior to applying brine to roads. Monthly reports on brine use for dust control, road stabilization, pre-wetting, anti-icing and de-icing must be submitted to the Department. Brine sources must be analyzed prior to being approved for use.

Colorado

Rule 907(e) allows disposal by roadspreading on lease roads outside sensitive areas for produced waters with less than 3,500 mg/l TDS when authorized by the surface owner and in accordance with an approved waste management plan. Roadspreading of produced waters shall not impact waters of the state, shall not result in pooling or runoff, and the adjacent soils shall meet the concentration levels in Table 910-1 of the 900 series of the Rules. Hydraulic fracturing flowback fluids shall not be used for dust suppression.

Ohio

Ohio Chapter 1509.226 states, "If a board of county commissioners, a board of township trustees, or the legislative authority of a municipal corporation wishes to permit the surface application of brine to roads, streets, highways, and other similar land surfaces it owns or has the right to control for control of dust or ice, it may adopt a resolution permitting such application as provided in this section. After the adoption of the resolution, the board or legislative authority shall prepare and submit to the chief of the division of oil and gas resources management a copy of the resolution. Any department, agency, or instrumentality of this state or the United States that wishes to permit the surface application of brine to roads, streets, highways, and other similar land surfaces it owns or has a right to control shall prepare and submit guidelines for such application, but need not adopt a resolution. Any person, who owns or has a legal right or obligation to maintain a road, street, highway, or other similar land surface, may file with the board of county commissioners a written plan for the application of brine to the road, street, highway, or other surface." Standards for the application of brine to roads, streets, highways, and other similar land surfaces are also included in Chapter 1509.226. Only brine that is produced from a well that is not a horizontal well shall be allowed to be spread on a road. Fluids from the drilling of a well, flowback from the stimulation of a well, and other fluids used to treat a well shall not be spread on a road.

West Virginia

West Virginia DEP and Division of Highways have a Memorandum of Agreement (MOU) for the beneficial use of natural gas well brines for roadway pre-wetting, anti-icing and deicing. The approve use is limited to wintertime. The use of hydraulic fracturing return fluids associated with horizontal or vertical gas wells is prohibited. Maximum contaminate levels criteria for the bines are included in the MOU. Application rates, mixing provisions training requirements are also included in the MOU. Each new source of brine must be analyzed and approved by West Virginia DEP prior to use.

New York

New York allows conventional formation brines to be used for pre-wetting, anti-icing and dirt road stabilization. The New York Department of Environmental Conservation requires brine sources to be tested as part of its beneficial use determination prior to a brine source being approved for roadspreading.

Roadspreading plans must avoid affecting state forest areas, wetlands and surface water bodies. NY DEC doesn't require annual reporting from brine-spreading operations.

Conclusion
Colorado, New York, West Virginia and Ohio all recognize the beneficial uses of production brine from conventional formations for dust control and road stabilization of dirt roads and pre-wetting, anti-icing and de-icing practices for paved roads during the winter months. Allowing the beneficial use of production brine from conventional formations allows Pennsylvania to be competitive with neighboring states in this respect by allowing operators to utilize the brine for uses that benefits operators and local governments.

Question 13
(13) Will the regulation affect any other regulations of the promulgating agency or other state agencies? If yes, explain and provide specific citations.

The regulations will not affect any other Department regulations or those of other state agencies. Generally, Chapter 78 and Chapter 78a regulations either use similar language or cross reference existing regulations of other Department programs for consistency. The language was either derived from or cross referenced to the following applicable Department regulations:

Conventional Operators

- *25 Pa.Code Chapter 77 (Noncoal Mining)* cross referenced in § 78.67 (relating to borrow pits);
- *25 Pa.Code Chapter 91 (General Provisions)* cross referenced in §§ 78.55 (relating to control and disposal planning) and 78.60 (relating to discharge requirements);
- *25 Pa.Code Chapter 92a (National Pollutant Discharge Elimination System Permitting, Monitoring and Compliance)* cross referenced in § 78.60;
- *25 Pa.Code Chapter 93 (Water Quality Standards)* cross referenced in § 78.60;
- *25 Pa.Code Chapter 95 (Wastewater Treatment Requirements) cross referenced in § 78.60;*
- *25 Pa.Code Chapter 102 (Erosion and Sediment Control)* cross referenced in § 78.1 (relating to definitions), 78.15 (relating to application requirements), 78.53 (relating to erosion and sediment control), 78.55; 78.59a (relating to impoundment embankments); 78.59c (relating to centralized impoundments); 78.60; 78.62 (relating to disposal of residual waste – pits); 78.63 (relating to disposal of residual waste – land application); 78.65 (relating to site restoration); and 78.67;
- *25 Pa.Code Chapter 105 (Dam Safety and Waterway Management)* cross referenced in §§ 78.1; 78.15; and 78.60;
- *25 Pa.Code Chapter 109 (Safe Drinking Water)* cross referenced in §§ 78.1; and 78.15;
- *25 Pa.Code Chapter 245 (Administration of the Storage Tank and Spill Prevention Program)* cross referenced in §§ 78.57 (relating to control, storage, and disposal of production fluids) and 78.66 (relating to reporting and remediating spills and releases);
- *25 Pa.Code Chapter 287 (Residual Waste Management—General Provisions)* cross referenced in §§ 78.1 and 78.58 (relating to onsite processing);
- *25 Pa.Code Chapter 299 (Storage and Transportation of Residual Waste)* cross referenced in § 78.70 (relating to road-spreading of brine for dust control and road stabilization);
- *Subpart D, Article IX (Residual Waste Management)* cross referenced in § 78.59c; and,

- *25 Pa.Code Chapter 250 (Administration of Land Recycling Program)* – cross referenced in § 78.66.

Unconventional Operators

- *25 Pa.Code Chapter 77 (Noncoal Mining)* cross referenced in § 78a.67 (relating to borrow pits);
- *25 Pa.Code Chapter 91 (General Provisions)* cross referenced in §§ 78a.55 (relating to control and disposal planning; emergency response for unconventional wells) 78a.60 (relating to discharge requirements);
- *25 Pa.Code Chapter 92a (National Pollutant Discharge Elimination System Permitting, Monitoring and Compliance)* cross referenced in § 78a.60 (relating to discharge requirements);
- *25 Pa.Code Chapter 93 (Water Quality Standards)* cross referenced in § 78a.60;
- *25 Pa.Code Chapter 95 (Wastewater Treatment Requirements)* cross referenced in § 78a.60;
- *25 Pa.Code Chapter 102 (Erosion and Sediment Control)* cross referenced in §§ 78a.1 (relating to definitions); 78a.15 (relating to application requirements), 78a.53 (relating to erosion and sediment control); 78a.55; 78a.59a (relating to impoundment embankments); 78a.59c (relating to centralized impoundments); 78a.60; 78a.65 (relating to site restoration); 78a.67; 78a.68 (relating to oil and gas gathering pipelines); 78a.68a (relating to horizontal directional drilling for oil and gas pipelines); and 78a.68b (relating to well development pipelines for oil and gas operations);
- *25 Pa.Code Chapter 105 (Dam Safety and Waterway Management)* cross referenced in §§ 78a.1; 78.15; 78a.60; 78a.68; 78a.68a; and 78a.68b;
- *25 Pa.Code Chapter 109 (Safe Drinking Water)* cross referenced in § 78.1;
- *25 Pa.Code Chapter 245 (Administration of the Storage Tank and Spill Prevention Program)* cross referenced in §§ 78a.57 (relating to control, storage, and disposal of production fluids) and 78a.66 (related to reporting and remediating spills and releases);
- *25 Pa.Code Chapter 287 (Residual Waste Management—General Provisions)* cross referenced in §§ 78a.1 and 78a.58 (relating to onsite processing);
- *Subpart D, Article IX (Residual Waste Management)* cross referenced in §§ 78a.59c and78a.68a; and,
- *25 Pa.Code Chapter 250 (Administration of Land Recycling Program)* cross referenced in § 78a.66.

Question 14

(14) Describe the communications with and solicitation of input from the public, any advisory council/group, small businesses and groups representing small businesses in the development and drafting of the regulation. List the specific persons and/or groups who were involved. ("Small business" is defined in Section 3 of the Regulatory Review Act, Act 76 of 2012.)

Representatives from the Department met with the following groups to specifically discuss the proposed and draft final-form regulations and solicit feedback:

- Oil and Gas Technical Advisory Board (TAB) – the Department discussed the regulatory concepts as well as the actual proposed regulatory language at the April 12, 2011, October 21, 2011, August 15, 2012, February 20, 2013 and April 23, 2013 TAB meetings. On April 23, 2013 the Board voted unanimously, with one member absent, for the Department to present the proposed rulemaking to the Environmental Quality Board.
- Following the April 2013 TAB meeting, the Department continued discussions on the topics contained in the proposed rulemaking at the TAB's June 12, 2013 meeting. On two occasions, TAB Subcommittees met to consider public resource impact permit screening, water supply replacement

quality, the general topic of waste management and the proposed area of review requirements – July 17-18, 2013 (Greensburg, PA) and August 14-15, 2013 (State College, PA). Participants in those meetings included associations representing the conventional and unconventional industries, consultants, attorneys, environmental groups and members of the public.

- The Department discussed the comments received on the proposed rulemaking and the draft final-form rulemaking with TAB at its June 26, 2014 meeting. At the September 25, 2014 TAB meeting, the Department discussed splitting the regulation into two individual Chapters as well as discussing significant changes to the rulemaking as it concerned conventional operators.
- In terms of the final-form rulemaking, the Department discussed the version of the regulations published under the ANFR process with TAB at meetings on March 20, 2015 and April 23, 2015. Following the close of the public comment period, the Department released an updated draft final-form rulemaking, which it discussed with TAB on September 2, 2015. TAB suggested changes to that document, so the Department considered those recommendations and further amended the draft final-form rulemaking and discussed this with TAB members on a webinar on September 18, 2015. The Department presented the final-form rulemaking appearing in Annex A to TAB at its October 27, 2015 meeting.
- The Department also discussed the draft final-form rulemaking with the Conventional Oil and Gas Advisory Committee (COGAC) in 2015. The Department formed COGAC in March 2015 in order to have an advisory body that was focused solely on the issues confronting the conventional oil and gas industry. The Department discussed the comments received on the proposed rulemaking and the draft final-form rulemaking with COGAC on March 26, 2015. Following the close of the public comment period, the Department released an updated draft final-form rulemaking, which it discussed with COGAC on August 27, 2015. COGAC suggested changes to that document, so the Department considered those recommendations and further amended the draft final-form rulemaking and discussed this with COGAC members on a webinar on September 18, 2015. The Department presented the final-form rulemaking appearing in Annex A to COGAC at its October 29, 2015 meeting.
- Small Business Compliance Assistance Advisory Committee – The Department provided an overview of the proposed regulations to the committee on October 24, 2012. This advisory committee is represented by small business owners who provide assistance and advice to DEP about how to assist small businesses with regulatory compliance and to ensure that small businesses are considered when new regulations are developed.
- DEP met with other industry representative groups on several occasions during the development of the proposed rulemaking, including: the Marcellus Shale Coalition (MSC), which is mostly comprised of businesses representing unconventional drillers; the Pennsylvania Independent Oil and Gas Association (PIOGA), which represents conventional drillers; and the American Petroleum Institute (API). In addition, the Department held regular meetings with industry representatives quarterly throughout the entire pendency of the rulemaking; the rulemaking generally and specific individual topics addressed by the rulemaking were standard agenda items at those meetings.
- Local government organizations were also involved in discussions of the proposed regulation, including Lycoming County Commissioner, Jeff C. Wheeland, the Pennsylvania State Association of Township Supervisors, and the Pennsylvania State Association of Boroughs.
- DEP also involved several environmental organizations in the development of these proposed regulations including the Chesapeake Bay Foundation, the Western Pennsylvania Conservancy, The Nature Conservancy, and the Pennsylvania Environmental Council. In addition, the Department held regular meetings with environmental organization representatives (including Clean Water Action and

the Delaware Riverkeeper) quarterly throughout the entire pendency of the rulemaking; the rulemaking generally and specific individual topics addressed by the rulemaking were standard agenda items at those meetings.

- The Department also consulted with its Sister agencies during the development of the proposed and draft final-form rulemaking, including the Department of Transportation, the Department of Conservation and Natural Resources, the Fish and Boat Commission, the Game Commission and the Historical and Museum Commission.

The public comment period on the proposed rulemaking ran for 90 days, starting December 14, 2013 (43 Pa. B. 7377) to March 14, 2014. The EQB also held nine public hearings on the proposed rulemaking, including:

- January 9, 2014, West Chester, PA
- January 13, 2014, Williamsport, PA
- January 15, 2014, Meadville, PA
- January 16, 2014, Mechanicsburg, PA
- January 22, 2014, Washington, PA
- January 23, 2014, Indiana, PA
- January 27, 2014 Tunkhannock, PA
- February 10, 2014, Troy, PA
- February 12, 2014 Warren, PA.

The Department received comments from approximately 25,000 commenters on the proposed rulemaking, including a significant number of form-letter comments/petitions. In addition, around 300 individuals testified at the nine public hearings.

Based on the review of those comments, the Department developed a draft final rulemaking that was formally published for public comment as an Advanced Notice of Final Rulemaking (ANFR) on April 4, 2015 (45 Pa. B. 1615). The public comment period on the ANFR ran for 45 days, until May 19, 2015, and the Department held three public hearings on the ANFR, including:

- April 29, 2015, Washington, PA;
- April 30, 2015, Warren, PA;
- May 4, 2015, Williamsport, PA.

The Department received comments from 4,947 commenters on the ANFR. Of the written comments, 302 were letters providing detailed or unique comments and 4,516 were form-letter comments. In addition, 129 individuals provided testimony on the ANFR at the three public hearings.

Question 15

(15) Identify the types and number of persons, businesses, small businesses (as defined in Section 3 of the Regulatory Review Act, Act 76 of 2012) and organizations which will be affected by the regulation. How are they affected?

Regulated Community

Unconventional Operators

According to the U.S. Small Business Administration, oil and gas well operators with less than 500 employees qualify as small businesses. There are currently 73 operators of unconventional well sites in Pennsylvania. The Marcellus Shale Coalition has estimated that less than half of these operators may be classified as a small business. Unconventional operators with applicable business operations will be required to comply with the provisions of the final-form regulation. For example, not all operators utilize pits or impoundments, therefore those sections would not apply to those specific operators. However, all unconventional operators are required to obtain a well permit; therefore, they would be required to comply with sections of the proposal relating to orphaned and abandoned well identification and impacts to public resources.

Conventional Operators
There are currently 5,808 operators of conventional oil and gas well sites in Pennsylvania, and most of them classify as a small business based on the US Small Business Administration's employee threshold. While most of the rulemaking that applies to unconventional operators also applies to conventional operators, bifurcation of the regulations into Chapters 78 and 78a and recommendations made by COGAC have led to the removal of portions of the rulemaking that did not substantially apply to conventional operators.

Although provisions such as §§ 78.56 (as they related to modular storage structures), 78.58 (onsite processing) and 78.59a – 78.59c (freshwater and centralized impoundments) apply to conventional operators, these operators do not usually employ the practices regulated by the provisions, and thus they should have minimal effect on conventional operators.

Pipeline Companies
Companies that build and install pipelines will be affected by proposed § 78a.68 relating to oil and gas gathering lines, § 78a.68a relating to horizontal directional drilling, and § 78a.68b relating to temporary pipelines for oil and gas operations. Each of these sections incorporates the requirements of Chapter 102 (relating to erosion and sediment control) and 105 (relating to dam safety and waterway management) into Chapter 78a. This cross-reference does not add any new regulatory requirements, as pipeline companies are already required to comply with these existing regulations. There are approximately 42 pipeline or midstream companies operating within the Commonwealth. The U.S. Small Business Administration defines a small business with NAICS code 237120 - Oil and Gas Pipeline and Related Structures Construction as having gross annual receipts of less than $33.5 million and NAICS code 486210 – Pipeline Transportation of Natural Gas as having gross annual receipts of less than $25.5 million. Because the small business determination is based on gross annual receipts, the Department is unable to determine the number of pipeline companies that would qualify as small businesses.

For more detail regarding affected small businesses, please see the Department's responses to Questions 24, 25 and 27, below.

Other Affected Entities
Land owners
Through this regulation, landowners will be notified and given and explanation of the consequences if they refuse an operator's request to access their land to conduct a pre drill survey. Under Act 13 of 2012, if a water supply is impacted from oil and gas extraction activities, and the landowner refused a pre-drill water survey, the presumption of liability of the operator is void. The final-form rulemaking codifies these statutory provisions in order to clarify landowner's rights and responsibilities. Additionally, under several provisions in this rulemaking landowner obtain notice of certain activities.

Local Government
A few local governmental entities may be affected by this proposal if they utilize brine for dust suppression or de-icing activities. Overall, the affect would be minimal as this rulemaking simply codifies existing practices of the Department for plan approval of these activities. Additionally, if local governmental entities manage public resources, they may be affected by the public resource impact screening provisions. Public resource agency involvement in the well permitting process not required by this rulemaking, but to the extent that a local governmental entity is a public resource agency, this rulemaking provides an opportunity to comment on potential impacts and necessary mitigation measures to protect public resource.

General Public
The general public, including those who appreciate and benefit from Pennsylvania's natural resources will be affected through the additional considerations included in this rulemaking to mitigate the impacts of the oil and gas industry. Local small businesses that depend on visitors to state parks and forests will also benefit. An analysis done by Penn State shows visitors to Pennsylvania's state parks generate more than $1 billion in economic activity in nearby communities and support almost 13,000 related jobs. Out-of-state users of Pennsylvania's natural resources account for $274 million of that total economic activity.

Additionally, all Pennsylvanians will benefit from the additional protective measures included in this rulemaking to prevent impacts of the oil and gas industry on the Commonwealth's water resources.

Question 16
(16) List the persons, groups or entities, including small businesses that will be required to comply with the regulation. Approximate the number that will be required to comply.

Unconventional Operators
According to the U.S. Small Business Administration, oil and gas well operators with less than 500 employees qualify as small businesses. There are currently 73 operators of unconventional well sites in Pennsylvania which will be required to follow the Chapter 78a provisions of the rulemaking. The Marcellus Shale Coalition, an industry trade group in Pennsylvania, has estimated that less than half of the operators affected may be classified as a small business.

Conventional Operators
Most conventional well operators can be classified as a small business using the U.S. Small Business Administration's employee threshold of 500 employees or less. There are currently 5,808 operators of conventional well sites in Pennsylvania, most of which classify as small businesses. These operators will be required to comply with the Chapter 78 provisions of the rulemaking.

Pipeline Companies
There are approximately 42 pipeline or midstream companies operating within the Commonwealth. Because the small business determination for pipeline companies is based on gross annual receipts of less than $33.5 million for oil and gas pipeline and related structures construction companies and less than $25.5 million for pipeline transportation of natural gas companies, the Department is unable to determine the number of pipeline companies operating in Pennsylvania that would qualify as small businesses. These operators will be required to comply with Sections 78a.68-78a.68b of the final rulemaking.

Question 17
(17) Identify the financial, economic and social impact of the regulation on individuals, small businesses, businesses and labor communities and other public and private organizations. Evaluate the benefits expected as a result of the regulation.

Impacts
The Department anticipates that the provisions of the final regulation will increase costs on oil and gas operators in the Commonwealth. The majority of the final regulation has been designed as performance based standards, allowing each individual operator to determine which practices they will employ for their extraction activities. Regarding the area of review provision, the impacts are determined to be minimal; as prudent oil and gas operators already complete well-search activities in advance of drilling to ensure the viability of their investment, i.e., new wells that communicate with existing wells may experience reduced recovery.

Many large unconventional operators employ contractors to perform various activities related to well pad siting, site construction, containment, and waste disposal. These contractors and those involved in the supply chain will receive a positive economic impact of these regulations through increased requirements for their specialized services. Companies who complete well-search activities and provide mapping/surveying services are also likely to be affected positively.

For more detail regarding affected small businesses, please see the Department's responses to Questions 24, 25 and 27, below.

Benefits
The provisions requiring operators to identify and consider the impacts of their operations on the Commonwealth's public resources will ensure that that the Department meets its constitutional and statutory obligations to protect public resources. The provisions that require operators to identify wells prior to drilling and monitor a higher-risk subset of such wells during hydraulic fracturing activities will minimize potential impacts to waters of the Commonwealth. The containment systems and practice requirements for unconventional well sites will minimize spills and releases of regulated substances at well sites and ensure that any spills or releases are properly contained. The amendments to the reporting releases requirements ensure statewide consistency for reporting and remediating spills and releases. Most of these practices are already being utilized by industry through best management practices.

The amendments contain several new notification requirements which will enable Department staff to effectively and efficiently coordinate inspections at critical stages of pit construction, modular above ground storage facility installation, drill cutting and residual waste disposal on well sites, horizontal directional drilling, and road-spreading activities. The notifications will allow Department inspectors to better utilize their time by visiting sites where there are active operations to inspect. Additionally, electronic submission requirements for well permits, notifications and predrill surveys will enhance efficiency for both the industry and the Department.

Please see the response to question 10 for further explanation of the specific benefits of this rulemaking.

Question 18

(18) Explain how the benefits of the regulation outweigh any cost and adverse effects.

For discussion of the benefits of this final-form rulemaking, please see response to Question 10.

This final-form rulemaking benefits the citizens of this Commonwealth because it contains more robust and comprehensive regulations for surface activities associated with conventional and unconventional operations. The regulated community will benefit from this rulemaking because it streamlines authorizations and approval processes and establishes performance based requirements that will avoid or minimize environmental impacts which can be costly to remediate. Many of the environmental performance standards contained in this final-form rulemaking are either a codification of current statutory or permit requirements or are already standard industry practices. As a whole, these regulations will strengthen measures aimed at reducing the potential impacts that oil and gas activities may have on the environment.

The provisions in this final-form rulemaking ensure that surface activities related to the development of conventional and unconventional wells are conducted in a manner that protects the health, safety, and environment and property of Pennsylvania citizens consistent with the environmental laws that provide authority for this final-form rulemaking. The final area of review regulation, which requires operators to document due diligence in a consistent manner and report unanticipated communication incidents that occur in a systematic way, will have far-reaching benefits and minimal costs. Addressing this particular issue has been supported by STRONGER, and comports with the Act, which intends that oil and gas wells be constructed in such a way to prevent gas and other fluids from entering sources of fresh groundwater.

Please see responses to Questions 22, 24, 25, 26 and 27. In developing this rulemaking, the Department has sought to minimize the adverse impacts to the regulated community while ensuring that surface activities related to the development of conventional and unconventional wells are conducted in a manner that protects the health, safety, and environment and property of Pennsylvania citizens consistent with the environmental laws that provide authority for this final-form rulemaking.

While there are additional costs associated with some of the provisions in the rulemaking, the benefits of this final-form rulemaking outweigh those costs.

The majority of these regulations focus on the proper handling, storage and disposal of materials needed for oil and gas operations and the wastes generated by those processes. The goal of these regulations is to prevent the release of these pollutional substances into the environment, including water resources, through reasonable means that are already standard industry practices. The costs of reasonable environmental protective measures are relatively small compared to the costs associated with cleaning up a release of a pollutional substance into the environment and restoring the impacted area.

In addition, these regulations require operators to identify public resources that may be adversely impacted by well operations. Costs associated with the data base query, field site visit and mitigation measure are minimal compared the benefit of conserving and maintaining the Commonwealth’s public resources in accordance with the Department’s constitutional and statutory obligations.

The costs associated with the area of review provision are minimal and expected to be related to reporting, as most prudent companies already complete well-search activities prior to hydraulic fracturing. Through the development of standardized reporting methods, reporting costs will be kept to a minimum.

Many of the other regulations in this final-form rulemaking are required to meet existing statutory obligations. Accordingly, any cost associated with those regulatory requirements is necessary to comply with applicable law.

In general, costs associated with pollution prevention measures are a small fraction of the costs associated with the cleanup and remediation of an area impacted with pollution. Therefore, a company's long term operational costs associated with employing pollution prevention measures costs far less than the long term operational costs of periodically having to clean up and remediate pollution caused by spills and releases.

<u>Question 19</u>

(19) Provide a specific estimate of the costs and/or savings to the ***regulated community*** *associated with compliance, including any legal, accounting or consulting procedures which may be required. Explain how the dollar estimates were derived.*

A summary table of estimated costs is provided in Appendix A. When no minimum cost was calculated, the minimum cost was assumed to be $0 for the purposes of the summary table.

Unconventional Operators Costs (Chapter 78a)

<u>Assumptions</u>

In the proposed rulemaking, the Department estimated based on data available at the time that there will be approximately 2,600 unconventional wells permitted each year for the next 3 years.

On average, about 1 out of every 2 permitted unconventional wells are drilled.

In addition, the Department estimated that there was an average of 3 unconventional wells per well site.

Since the time the proposed rulemaking was published for public comment in December 2013, the Department was able evaluate the rate at which unconventional wells are permitted and drilled in Pennsylvania and include data for 2013, 2014 and the first 3 quarters of 2015.

The Department's records also show that there are currently 3,387 unconventional well pads with at least one well drilled and a total of 9,486 total unconventional wells located within the Commonwealth. This equates to an average of 2.8 wells per pad. In the future, it is estimated that less well sites will be built as there could be as many as 22 wells on a pad, based on data available to the Department.

The cost analysis for this chapter must be factored on a well site basis, not on a per well basis. Many of the processes proposed for regulation in this rulemaking include activities integral to the operation of several wells and even several well pads.

Year	Unconventional Wells Permitted	Unconventional Wells Drilled
2010	3,364	1,599
2011	3,560	1,960
2012	2,649	1,351
2013	2,965	1,207
2014	3,182	1,327
2015*	1,919*	756*

***Data extrapolated from first 3 quarters (1,439 wells permitted, 567 wells drilled as of 9/8/2015)**

Based on the data shown in the above table which represents the most recent 5-year period in history, the Department's estimate in the proposed rulemaking was relatively accurate. The number of wells permitted exceeded the Department's estimate but the percentage of permitted wells that have been drilled is approximately 46% since 2010 and 41% since 2013 which is lower than the Department's original estimate. The Department does not believe that the new data collected since the proposed rulemaking was published supports a change to its original estimate of 2,600 wells permitted per year and 1,300 wells drilled per year as a reasonable conservative estimate of the potential unconventional well drilling activity over the next 3 years.

The Department believes that the number of unconventional wells per well site will rise in time but has retained the estimate of 3 wells per well site for the purposes of this estimate because it is reflective of current conditions and what is expected over the next 3 years.

2,600 wells permitted x 50% of wells drilled = **1,300 wells drilled each year**
1,300 wells drilled each year ÷ 3 wells per well site = **434 well sites built each year**

Cost Estimates

The Department reached out to well operators, subcontractors, and industry groups to derive the cost estimates of this final-form rulemaking.

Electronic Filing

In the final-form rulemaking, nearly all applications and notifications required by the rule are to be made to the Department electronically. Electronic reporting of production data for all operators was established by the "Oil and Gas Well Cementing and Casing" rulemaking (41 Pa.B. 805) in 2011 and is not a new requirement established by this rulemaking. Therefore, all operators should already be registered with the Department and submitting information to the Department electronically.

The primary new requirement in §§ 78.121 and 78a.121 is for the operator to report the specific facility or well site where waste was managed. Providing such information to the Department is a standard practice in all waste management programs and does not single out the oil and gas industry.

The Department will not assume non-compliance with existing requirements. Because operators have been required to provide production data to the Department electronically for several years, conventional operators should already have the necessary equipment and access necessary to provide electronic data to the Department.

Therefore, the Department is not assigning additional costs based on the requirements of this final-form rulemaking.

New notifications to the Department

The final rule includes a number of new notification requirements. Operators must provide at least 3 days' notice to the Department prior to conducting the following activities.

- installation of pit liner (78.56)
- prior to commencing construction of a pit of greater than 250 ft^2 for servicing, plugging or recompleting a conventional well (78.56(e))
- prior to disposal of cuttings (78.61-78.63)
- prior to conducting onsite processing (78.58)
- prior to utilizing modular aboveground storage structure (78.56)
- after noticing deficiencies in tanks during monthly or quarterly inspections (78.57(h))

The total new cost of this provision is $0.

Identification of Public Resources (§78a.15(f)-(g))
The requirements in this section ensure that the Department meets its constitutional and statutory obligations to protect public resources. I

The Department received significant public comment on these provisions from unconventional gas well operators related to the cost of implementing the public resource screening process requirements in Section 78.15(f)-(g). Commenters disagreed with the Department's estimates of cost for permit conditions mitigation measure to protect public resources. Commenters also argued that there will be considerable expenses related to personnel time, expert consultants needed for surveys and project delays in associated with the responses from public resource agencies. The Department acknowledges that there is some cost associated with implementing these requirements. The total cost of this provision will vary on a case-by-case basis. This cost is dependent on several variables including, the number of well sites that are within the prescribed distances or areas listed, the type and scope of operations within prescribed distances or areas, the type of public resource, the functions and uses of the public resource, specific probable harmful impacts encountered and several other variables and the available mitigation measure to avoid, mitigate or otherwise minimize impacts. Because so many significant variables exist, the cost estimate for implementation of the entire provision will vary. For that reason, the Department provides below an estimate for specific steps which allow for an estimate to be made.

The first step in the process is identification. The Department believes this process would be required for all new well sites. First an electronic review can be conducted with the Pennsylvania Conservation Explorer's online planning tool. This tool will allow operators to identify the location of the majority of public resources which require consideration under the final rule. This tool also will allow the operator to identify potential impacts to threatened and endangered species, which also must be addressed under § 78a.15(d). Since the tool may not have data to identify all the public resources listed in Section 78a.15(f)(1), operators will also need to conduct a field survey of the proposed well site area to identify public resources. This field survey will likely include identification of schools and playgrounds 200 feet from the limit of disturbance of the well site. The Department estimates the cost of this field survey to be $2,000 and the cost of the electronic survey to be $40. Even though use of the online tool is currently required to comply with requirements protecting threatened and endangered species, the Department has included the cost in this estimate nonetheless.

$2,000 x 434 = $868,000
$40 x 434 = $17,360

$868,000 + $17,360 = $885,360

The second step of the process is consultation with the public resource agency. This process is only applicable to well sites which are within the prescribed distances or areas listed in Section 78.15(f)(1). The Department estimates that 30% of well sites will fall within these distances or areas. Operators will be required evaluate the functions and uses of the public resource, determine any probable harmful impacts to the public resource and develop any needed mitigation measures to avoid probable harmful impact. Operators must also notify potentially impacted pubic resource agencies of the impact and provide those public resource agencies the same information provided to the Department. Cost of the provision is dependent on the number of well sites impacted as well as the complexity of evaluating the functions and uses of the public resource. The Department estimates the postage will cost $20 per notification to public resource agencies.

$20 x 434 x 30% = $2,604

Due to the complexity of the variables in this process, the estimate for the cost of evaluating the functions and uses of the public resource and determining whether there is a probable harmful impact will vary. In some cases, functions and uses of the public resource and any probable harmful impacts may be immediately obvious and others may be far more complex and may include multiple public resources.

The final step in the process is mitigation. The cost estimate for mitigation will vary. In some circumstances, an operator may be able to plan the location of the well site using the planning tool discussed above to avoid public resources resulting in zero cost. Any cost associated with mitigation measures is dependent on many variables and may be situation specific in some cases. While the Department is unable to provide a specific estimate for the implementation of this entire provision, it should be noted that this cost may be substantial depending on the location of the well site.

$885,360 + $2,604 = $887,964

The total cost of this provision is $ $887,964 *(not including consultation and mitigation).*

Protection of water supplies (§78a.51)

This section provides the Department's interpretation of the water supply restoration and replacement in Section 3218(a) of the 2012 Oil and Gas Act. This section seeks only to provide clarity to existing statutory requirements. Accordingly, the estimated new cost incurred by unconventional operators is $0.

The total new cost of this provision is $0.

Area of Review and Monitoring Plans (§78a.52a and §78a.73)

$8,720

$8,720 x 1,300 wells = $11,336,000

The total cost of this provision is $11,336,000.

The Department's 2013 Regulatory Analysis estimated the compliance cost at $2,000 per new well. That Department estimate was made before the revisions to the final-form rulemaking, including;

a. Researching the depth of identified wells;
b. Development of monitoring methods for identified wells, including visual monitoring under accompanying section 78.73;
c. Gathering surface evidence concerning the condition of identified wells;
d. Gathering GPS, i.e., coordinate data for identified wells;
e. Introduction of a provision of advanced notice to adjacent operators under accompanying section 78.73; and
f. The assembly of the above data in an area of review report and monitoring plan and the submission of the report at least 30 days prior to the commencement of drilling the well at well sites where hydraulic fracturing activities are anticipated.

With the additional items, the cost of compliance is expected to exceed $2,000 per well. However, it is important to emphasize that industry commentators have indicated the majority of the work required as part of the area of review is already performed by operators in an effort to not only reduce potential environmental liability, but also to protect the investment associated with the drilling and stimulation of a new well, which represents millions of dollars for a typical unconventional well.

Further, it should be emphasized that the costs associated with the review of historical data will be negligible, as most unconventional companies already have subscriptions to well-location databases. EDWIN, which is one of the primary databases used for retrieving records related to oil and gas wells in Pennsylvania, costs $500 per year for a full subscription. For a company drilling 25 wells a year this results in a cost of $20 per well along with search and retrieval costs. Many other sources of information are free.

Most unconventional companies hire professional engineering firms to complete surveying activities. Estimates for the generation of plats, which are already required for well drilling permits, are expected to range between $4,000 and $5,000, with an average cost of $4,600. These costs were gathered by speaking with companies that routinely perform this work for the unconventional industry. Assumptions include two (2) days of field work and one (1) day of office work to compile the data necessary for submission. It should be noted that current laws in Pennsylvania only require that survey data be collected by a “responsible surveyor or engineer,” and that existing law under Section 3213(a.1) of Act 13 and the prior 1984 Oil and Gas Act has required operators to identify all abandoned assets discovered on their leases to the Department for many years. It is noted that one company providing information did ask that the Department consider the additional burdens being placed on the industry and expressed concerns that more oil and gas activities would be shifting to neighboring states as a result of this regulation. The individual had asked that limits be placed on offset wells requiring identification in the area of review (active only) and had indicated that landowners in drilling units have reacted in a confrontational manner with members of his staff in the past.

The Department has experience monitoring well vents in its plugging program. Costs are anticipated to remain under $500 per day per offset well; although the number of wells requiring continuous monitoring is not expected to be very high on a case-by-case basis, as monitoring candidates must not only penetrate the zone expected to be influenced by hydraulic fracturing, but also represent a high enough risk that continuous monitoring is deemed warranted. In many cases avoidance mitigation measures, plumbing a tank to the well of concern or inspecting offset well sites periodically may be all that is necessary. For at least a fraction of the well drilled, no offset wells will penetrate the zone of concern and monitoring costs will be negligible. This cost item is expected to range from negligible amounts to a maximum of $7,500 per well site, with an average cost of $3,500.

There are nominal costs associated with a certified mailing program that assumed 100 landowners are contacted in association with a well site at a cost of $6.00 per mailing.

Although the Department contends that the work specified in this section of the regulation is already being conducted by responsible unconventional operators in the state and implementation will merely result in a marginal incremental cost for reporting, its cost analysis based on speaking with qualified professionals and its own experience contracting services in its well plugging program projects that total costs for an unconventional well operator employing standard industry practices could conceivably average around $9,000 per well site.

For comparison, the Department recently analyzed costs associated with several unconventional well hydraulic fracturing communication incidents documented in Pennsylvania. The circumstances surrounding these incidents varied: three involved communications between a well being stimulated and a nearby well being drilled, another involved communication between two stimulated wells that had not been flowed back and a wellbeing hydraulically fractured on the same pad, and the last involved communication with a previously unknown and inadequately plugged conventional well. Costs associated with unconventional wells tend to be derived from a more complicated set of variables that not only must factor in the equipment being used and subsequently placed on standby at the time of the incident (e.g., costs range from $10,000 to $50,000 per day); but also lost revenues in association with delayed production and the need to meet gas-market commitments by established deadlines that may prompt reconfiguring existing well network flow-to-pipeline parameters and/or purchasing gas on the open market. These costs are potentially further compounded by any environmental issues that must be addressed (e.g., water well sampling/monitoring and analytical costs and consultant costs for data analysis and interpretation), logging and downhole camera costs to inform any well work that must be completed, plugging costs of any unconventional wells affected beyond repair and any improperly plugged legacy wells, material costs (e.g., loss of drilling muds that are normally rented), increased monitoring costs at nearby gas wells, increased time spent bleeding pressure down in the reservoir, and accelerated expenditures to prepare a new site. Cost estimates for the first three incidents ranged from $90,000 to $800,000. Total costs for the second scenario, which involved plugging two drilled unconventional wells that had not been brought back into production, are estimated at $13,000,000 to $16,000,000. Total costs for the third scenario were in excess of $1,000,000. The Department acknowledges that in certain cases, even with the implementation of the regulation and the application of best practices, that some percentage of communication incidents will still take place. However, it adds that this regulatory concept is being addressed and acknowledged by a number of other regulatory programs, the STRONGER organization and API, a globally recognized industry trade organization. It is also significant to note that a single, severe hydraulic fracturing communication incident is capable of exceeding the estimated annual cost of implementation for an entire unconventional industry.

Site Specific PPC Plan (§78a.55)

The final rule requires all oil and gas operators to develop and implement a site specific PPC Plan under §§ 78.55 and 78a.55. The Department received significant public comment from oil and gas operators on this section. Commenters expressed concerns about §§ 78.55(a) and 78a.55(a) which simply reiterate the requirements already existing in Chapters 91.34 and 102.5(l). Since §§ 78.55(a) and 78a.55(a) do not establish any new requirements, the Department does not believe that this subsection presents any new burden on operators and no cost was attributed with these provisions.

The Department initially estimated that the new cost of this requirement would be between $86,800 and $130,200 but upon further evaluation, the Department has revised this estimate. The requirement for operators to develop a control and disposal plan or PPC plan has been in existence under § 78.55 since 1989 when Chapter 78 was first promulgated. A plan that does not address the specific needs of a site could not and should not be considered to meet the requirements of § 78.55. Therefore, in order for operators to ensure that they were in compliance with the planning requirements in § 78.55, they must have been evaluating their PPC or control and disposal plans against site specific conditions since 1989. In addition, it is not the intent of this rulemaking nor is it required by this rulemaking that each PPC plan developed for a different well site must be unique. Therefore, the Department does not believe its initial estimates are accurate. Instead, the Department estimates the new cost associated with this requirement to be negligible because operators have been required to develop these plans since 1989.

It is not the intent of this rulemaking to ensure that all PPC plans are revised annually. There are no specific review and update timeframes included in the rulemaking. The rule requires revisions to the plan in the event that practices change. Therefore, if conditions at the site do not change, there will be no need to make revisions to the PPC plan. In addition, operators have been required to revise their plans under these same conditions since Chapter 78 was initially promulgated in 1989. Therefore, there is no new cost attributed to this provision.

Finally, the rule does not include a requirement that every single site where activities including the impoundment, production, processing, transportation, storage, use, application or disposal of pollutants must have the PPC Plan posted on site at all times. The rule does not include this requirement or anything resembling this requirement. In fact, the rule does not require the PPC plan to be maintained on the site at all. The Department believes that it is prudent for operators to maintain the PPC plan on the site when the site is active including, drilling, alteration, plugging or other activities where there is an increased risk of a spill, release or other incident, but it is not required by § 78.55. Therefore, there is no new cost attributed to this requirement.

The total new cost of this provision is $0 (negligible).

Providing copies of the PPC Plan to and PA Fish and Boat Commission and the Landowner (§78a.55(f))

The final rulemaking includes a requirement for operators to provide copies of the site specific PPC Plan to the Pennsylvania Fish and Boat Commission and the landowner upon request. The cost associated with this requirement depends on the number of plans that are requested. If no plans are requested, there is no cost associated with this requirement. If the landowner and the Fish and Boat Commission request the plan for every well site, the Department estimates the cost to be $21,700.

434 x $25 x 2 = $21,700.

The total new annual cost of this provision is estimated to be $21,700.

Banning Use of Pits (§ 78.56)

The final rule disallows the use of pits for temporary storage of waste at unconventional well sites. The Department does not believe that this provision will result in any significant cost because pits are rarely used for this purpose at unconventional well sites.

The final rule also requires pits at unconventional well sites to be restored within 6 months of the date of the final rule. The Department does not anticipate that this provision will result in any significant new cost because pits are rarely used at unconventional well sites and because pits regulated under § 78.56 are already required to be restored within 9 months of completion of drilling of the well serviced by the site.

The estimated new cost of this provision is $0.

Fencing Around Unconventional Well Site Pits (§78a.56(a)(5))

When initially proposed the rule required unconventional operators to install fencing around pits on well sites. The final rule does not allow unconventional operators to utilized waste pits on their well site. Since this provision does not exist, there is not associated cost.

The total cost of this provision is $0.

Determination of Seasonal High Groundwater Table for Pits & labor to inspect and test the integrity of the liner (§78a.56(a) and 78a.62)

When initially proposed the rule required unconventional operators to make a determination of the depth to seasonal high groundwater table and inspect liners for pits on well sites. The final rule does not allow unconventional operators to utilized waste pits on their well site. Since this provision does not exist, there is not associated cost.

The total cost of this provision is $0.

Tank Valves and Access Lids Equipped to prevent unauthorized access by third parties (78a.56(a) (7) and §78a.57(h))

If the well site has 24-hour security presence, the operator satisfies the requirements of this section. This calculation assumes that all well sites will not have 24-hour security. This should be a one-time expense as the protective measures will be affixed to the tanks. The Department estimates $7,000 for each well site.

$7,000 x 434 = $3,038,000

The total cost of this provision is $3,038,000.

Signage for tanks and other approved storage structures (§78a.56(a)(8))

Unconventional operators will be required to display a sign on the storage structure identifying the contents and if any warnings exist, such as corrosive or flammable.

The cost of this regulatory requirement depends on the number of tanks/storage structures and the types of signage used. The Department assumes that the cost can be in the range of $250 - $2,000 for each well site.

$250 x 434 = $108,500
$2,000 x 434 = $868,000

The total cost of this provision is between $108,500 and $868,000.

Vapor Controls for Condensate Tanks (§78a.56(a)(10))

Vapors must be controlled at all condensate tanks. Based on DEP inspection experience, this calculation assumes that only 40% of well sites will have condensate tanks. The Department estimates $12,500 for each well site.

$12,500 x (434 x 40%) = $2,170,000

The total cost of this provision is $2,170,000.

Secondary Containment for all aboveground structures holding brine or other fluids (§78a.57(c))

The cost of this regulatory proposal depends on the number of aboveground structures on each well site. The Department assumes that the cost can be in the range of $5,000 - $10,000 for each well site.

$5,000 x 434 = $2,170,000

$10,000 x 434 = $4,340,000

The total cost of this provision is between $2,170,000 and $4,340,000.

Identification of existing underground/ partially buried storage tanks and registration of new underground/ partially buried storage tanks (§78a.57(e))

When initially proposed, the rule prohibited the use of underground or partially buried storage tanks for storing brine. Under the final-form rulemaking, operators would have 3 years to remove all existing underground or partially buried tanks. The Department's initial cost estimate did not attribute a cost to this provision because the cost was dependent on the number of buried tanks across the Commonwealth and the Department was unable to estimate the number of buried tanks at that time. As a result of public comment, the Department has amended the final rule to allow the use of buried tanks by both conventional and unconventional well site operators and does not require removal of existing buried tanks. The Department continues to believe that underground storage tanks warrant extra scrutiny because they are not as easily inspected and can provide a more direct conduit for contamination into groundwater and therefore has included provisions in the final rule to require the location of all existing and any new underground storage tanks at well sites to be reported to the Department. Therefore, the original estimate of $20,000 is retained. The Department does not believe that there will be any significant new cost associated with notifying the Department of newly installed underground or partially buried tanks.

The total cost of this provision is estimated to be $20,000.

Corrosion protection for permanent aboveground and underground tanks (78a.57(f)-(g))

Subsections 78.57 (f)-(g) implement Section 3218.4(b) of Act 13 which establishes that permanent aboveground and underground tanks must comply with the applicable corrosion control requirements in the Department's storage tank regulations.

It is common knowledge that steel structures, including storage tanks, corrode or rust and fail when left unprotected and exposed to the elements. It is also common knowledge that brine or salt water which is commonly stored in tanks at conventional well sites increases the rate of corrosion of steel. Given these facts and considering that the estimated cost for replacement tanks is significantly higher than the estimated cost for providing corrosion protection for those same tanks (see table below, the estimated costs for providing corrosion protection is less than half the cost of a new tank), the Department believes that it would behoove gas operators to provide corrosion protection for their tanks because it can extend the useful life of the tank significantly at a fraction of the cost of replacing the tank. In fact, this provision may represent a cost savings to operators that had previously not been maintaining their tanks appropriately.

Size(bbl)	Current Cost	Cathodic Protection	Corrosion Protection	Ratio of Cost of Corrosion Protection to Replacement
25 bbl.	$1,800.00	$350.00	$450.00	0.44
50 bbl.	$2,200.00	$350.00	$650.00	0.45
100 bbl.	$3,451.00	$350.00	$1,200.00	0.45
140 bbl.	$5,144.00	$350.00	$1,300.00	0.32
210	$6,083.00	$350.00	$1,600.00	0.47

Finally, this requirement is a statutory requirement under section 3218.4(b) of Act 13. As noted above, subsections 78.57(f)-(g) simply implement this requirement. The Department has also explicitly removed the requirement to use Department certified inspectors to conduct inspections of interior linings or coatings which will alleviate some burden on oil and gas operators. Operators may choose to use non-metallic tanks which can often be less expensive than steel equivalent and do not require any additional cost to ensure protection from corrosion.

Since this section implements existing statutory requirements no cost is assigned to this provision.

The estimated new cost of this provision is $0.

Monthly Maintenance Inspection (§ 78a.57(i))

Section 78a.57 imposes a new requirement for operators to conduct periodic inspections of tanks used to control and store production fluids on a well site and document each inspection. The monthly maintenance inspection is intended to be a visual check of the tank and containment area to ensure that the tank and containment structures are in good working condition and that ancillary and safety equipment are in place and in good working condition. The Department estimates that on average, inspection of each tank, including filling out the inspection form will take 15 minutes. When initially proposed this provision required use of forms provided by the Department but in response to comments the provision was revised to allow operator generated forms. The Department will provide a form for use by operators that prefer to use the Department's form or do not have their own inspection documentation.

The Department estimates that the unconventional industry utilizes approximately 30,000 tanks. With a labor rate of $30/hr. the cost to perform monthly maintenance inspections is $2,700,000 per year or $90 per tank per year.

Based on comments received, the Department believes that the majority of unconventional well operators are already engaged in some form of periodic tank inspection. With the flexibility of being able to use operator generated forms, the Department does not believe that this provision represents a significant burden on unconventional operators.

The Department believes that periodic inspections are appropriate common sense accident prevention steps that every storage tank operator should follow. In addition, it is almost always less costly to prevent an accident than to remediate the harm that is caused when an accident occurs. Remediation of a single spill could cost more the total annual cost to inspect all storage tanks utilized unconventional oil and gas well operators.

The estimated new annual cost of this provision is $2,700,000.

Radiation protection action plan (§ 78a.58 (d))

The Department has added 78.58(d) to this rulemaking which requires an operator processing fluids onsite to develop a radiation protection action plan which specifies procedures for monitoring and responding to radioactive material produced by the treatment process. This section also requires procedures for training, notification, recordkeeping, and reporting to be implemented. This section does not require review or approval by the Department prior to implementation of the plan. In addition, the Department does not believe that a new or unique plan must be developed for each individual well site where processing occurs. Many operators will probably find that a single plan developed under this provision is applicable to processing operations over large geographic areas.

The Department estimates that processing which would require this plan occurs on approximately 75% of well sites or 326 sites per year.

434 sites x 75% = 326 sites

The Department also estimates that plans developed under this provision will be applicable to 50% of an operator's sites on average or 163 sites per year.

326 sites x 50% = 163 sites

Some operators may only need a single plan and others may need several, depending on their operations.

The Department estimates that development of a radiation protection action plan under this section will cost between $2,000 and $5,000 per plan for initial development. In addition, in order to implement the plan, operators who develop a plan will need to purchase a dose rate meter. The Department estimates the cost of the dose rate meter to be $1,000-$2,000. Finally, operators will be required to provide training on the plan to staff. This training is typically conducted by the plan development consultant but may be conducted by others. The Department estimates that annual training of staff will cost $1,000- $2,000 per plan.

Cost of Development
163 x $2,000 = $326,000
163 x $5,000 = $815,000

Cost of Training =
163 x $1,000 = $163,000
163 x $2,000 = $326,000

A new meter will not be required for each plan. Operators may be able to use the same meter for multiple sites throughout the year depending on the location of the site. The Department estimate that industry will need to purchase 85 dose rate meters to comply with this requirement.

Cost of meters
85 x $1,000 = $85,000
85 x $2,000 = $170,000

The total annual cost is equal to the cost of development plus the cost of training. The total initial cost is equal to the cost of meters.

$326,000 + $163,000 = $489,000
$815,000 + $326,000 = $1,141,000

Therefore, the estimated annual cost of this provision is between $489,000 and $1,141,000 and the estimated initial cost is estimated to be between $85,000 and $170,000.

Well Development Impoundment Construction Standards (78a.59a, 78a.59b)

In the final rule, §§ 78a.59a and 78a.59b impose construction and operation standards for well development impoundments including embankment construction standards, the need for surrounding well development impoundments with a fence and providing an impermeable plastic liner. The department received comments from unconventional operators indicating that the cost of all new requirements applicable to well development impoundments, excluding fencing around the impoundment, is $250,000 to $500,000 per impoundment and a total cost of $25,000,000 based on the Department's estimate of 100 existing freshwater impoundments. The commenter does not provide a breakdown of how the projected cost was derived.

The Department disagrees with the commenter's cost estimate. First, many of the new requirements are only applicable to new impoundments. Operators must only certify that existing impoundments meet the requirement for having a synthetic liner, being surrounded by a fence and properly storing mine influenced water. The rule does not require any certification of structural integrity or a groundwater depth determination for existing impoundments so those costs should not be considered for existing impoundments. The requirement to ensure that mine influenced water is properly stored exists regardless of the well development requirements in Chapter 78 so those costs should not be considered for existing impoundments.

The Department understands that the majority of existing well development impoundments already have an impermeable synthetic liner. In addition, it is important to note that the well development impoundment requirements do not apply to water sources such as lakes or ponds, so to the extent that commenters included these types of facilities in their cost estimate, they may have overestimated. The Department estimates that 90% of the existing well development impoundments have a synthetic liner installed so only a small number of well development impoundments will require addition of a synthetic liner under the rule. The Department made the initial estimate of 100 existing well development impoundments in 2013 which would equate to an average of 20 well development impoundments constructed per year. Based on this rate of development, the number of existing well development impoundments is estimated to be 140 since 2 years have passed since the initial estimation.

The Department estimates that on average, a well development impoundment will require 250,000 ft^2 of synthetic liner to comply with the rule. The estimated cost of installed 30 mil HDPE liner to meet this requirement is \$0.40/ft^2 resulting in a total cost of \$1,260,000.

250,000 x 0.40 x 90% x 140 = \$1,260,000 for liner installation

The cost of the fencing is dependent upon the size of the impoundment and the type of fencing used determines. Based on 140 well development impoundments throughout the Commonwealth and assuming that none of them currently have fencing the Department estimates that the total cost of this provision is between \$980,000 and \$7,000,000.

\$7,000 x 140 = \$980,000

\$50,000 x 140 = \$7,000,000

The rule also requires operators to register the location of well development impoundments with the Department. Assuming a total of 140 existing well development impoundments, the Department estimates a total cost of \$13,000.

\$1,260,000 + \$980,000 + \$13,000 = *\$2,253,000*

\$1,260,000 + \$7,000,000 + \$13,000 = *\$8,273,000*

The initial cost of this provision is estimated to be between \$2,253,000 and \$8,273,000.

For new impoundments, the total cost is dependent upon the number of new impoundments constructed. Based on past trends, the Department estimates that 20 new well development impoundments will be constructed each year. The standards under § 78a.59b provide reasonable requirements to ensure that well development impoundments are structurally sound and protective of public health and safety and the environment. The standard of structurally sound and protective of public health and safety and the environment is a standard that all well development impoundments should meet. To the extent that operators are currently engaged in the practice of constructing and operating impoundments that are not structurally sound and protective of public health and safety and the environment, the Department asserts that they are not only operating irresponsibly but also out of compliance with Department regulations. The Department also notes that § 78a.59a(b) allows an owner or operator to deviate from the requirements in this section provided that the alternate practices provides equivalent or superior protection to the requirements in §§ 78.59a and 78a.59a. Therefore, these sections should not create any significant new costs to responsible operators.

The Department estimates the cost of determining the depth of the seasonal high groundwater table to be $3,500 per impoundment.

The Department estimates a total cost of $100,000 for installing liners in each impoundment based on the cost of $\$0.40/ft^2$ for installed 30 mil HDPE liner and 250,000 ft^2 of liner per impoundment on average.

The Department estimates the cost of installing fencing to be $7,000 - $50,000 per impoundment depending on the size of the impoundment and the type of fencing used.

This results in a total estimated cost of $110,500 and $153,500 per impoundment and a total annual cost of $2,210,000 and $3,070,000.

($3,500 + $100,000 + $7,000) x 20 = *$2,210,000*

($3,500 + $100,000 + $50,000) x 20 = *$3,070,000*

Therefore, the total estimated annual cost of this provision is between $2,210,000 and $3,070,000.

Centralized Impoundment (§ 78a.59c)

The final rule requires unconventional operators to either close or obtain a permit from the Department's waste management program for existing centralized impoundments. The Department did not include a cost estimate for this provision when the rule was initially proposed because it allowed for continued use of these facilities under Chapters 78 and 78a. The cost of this provision is dependent on the number of facilities impacted and how operators decide to comply. The Department received significant comment on this section from unconventional operators. Commenters estimate that the cost to permit a new centralized impoundment under Chapter 289 may increase by $120,000 to $230,000 based on site conditions. Commenters also noted that if an operator chooses to close an existing permitted centralized impoundment due to this rule, an owner may realize a loss of $1,500,000 to $2,500,000 of investment plus the immediate additional costs to restore the site. If a centralized impoundment permit has been submitted to the Department under the current regulations and is pending review, an applicant would realize a loss of $150,000 to $250,000 plus costs associated with the time to prepare the application as a result of this revision.

The Department does not agree with these cost estimates. First, the costs associated with restoration of existing centralized impoundments should not be considered because restoration of the centralized impoundment has always been required. Second, the standard for construction of a centralized impoundment under Chapter 78 and the Department's existing centralized impoundment program are substantially similar to those required by the residual waste regulations. The Department believes that the majority of costs associated with development of pending applications under the existing centralized impoundment program are applicable to the costs associated with the residual waste permit and therefore no cost should be associated with pending applications.

The cost associated with this provision is dependent on the number of impoundments impacted. There are a total of 26 centralized impoundments operated by 6 unconventional operators in the Commonwealth. The Department believes that operators will choose to restore a number of the existing impoundments rather than obtain a permit from the Department's waste management program because older centralized impoundments were not constructed to standards as closely matched to the waste requirements as newer impoundments and those older impoundments also may be approaching the end of their useful lives. The Department presumes that the replacement cost for each centralized impoundment is between $1,500,000 and $2,500,000. To the extent that operators choose to restore and replace all of the existing centralized impoundments, the estimated cost of this provision is between $33,000,000 and $55,000,000.

20 x $1,500,000 = *$30,000,000*

20 x $2,500,000 = *$50,000,000*

The initial cost of this provision is estimated to be between $39,000,000 and $65,000,000.

Based on past trends, the Department estimates that 4 centralized impoundments will be constructed per year. If the cost to permit and construct impoundments under the Chapter 289 is $120,000 to $230,000 per impoundment, the estimated annual cost is between $480,000 and $920,000.

Therefore, the total estimated annual cost of this provision is estimated to be between $480,000 and $920,000.

Onsite Disposal (§78a.62-63)

The final rule requires unconventional operators to obtain a permit from the Department prior to disposing contaminated drill cuttings or drill cuttings from below the surface casing seat either in a pit or by land application on the well site. This revision removes the permit by rule structure for waste disposal on unconventional well sites. The Department does not expect this provision to add any significant cost for unconventional operations. It has become less and less common for unconventional operators to utilize onsite disposal of contaminated drill cuttings and drill cuttings from below the surface casing seat. In fact, there have been many instances, where unconventional operators have exhumed previously encapsulated cuttings due to liability concerns. In addition, the practice of drilling many wells on a single site is generally incompatible with onsite disposal simply due to the volume of waste materials generated and the limited space available. An example of this is the Big Sky pad in Green County where a total of 22 wells have been drilled as of May 2015.

The total cost of this provision will be dependent on the number of well sites where operators seek permits for onsite disposal. The Department's review of waste disposal data for unconventional wells shows that for the reporting periods from January-June of 2014, July-December 2014 and January-June 2015 cuttings from only 5 wells have been disposed through onsite encapsulation and no cuttings have been disposed through land application. During that same time period, 1,746 unconventional wells were drilled so less than 0.3% of wells utilized onsite disposal. In addition, the 5 wells which utilized onsite disposal were vertical wells that generated 100-120 tons of cuttings so the total mass of cuttings disposed during that time was less than 600 tons while the total mass of drill cuttings generated during that time was over 2.1 million so less than 0.03% of the total mass of cuttings generated by unconventional wells was disposed through onsite disposal. Since these methods are so rarely used, the Department does not believe that this provision will impose any significant cost to the unconventional industry.

The total new cost of this provision is $0.

Alternative Waste Management (§78a.63a)

This section codifies the existing practice of requiring approval for alternative waste management practices. There is no cost associated with this section.

The total new cost of this provision is $0.

Secondary Containment (§78a.64a)

The final-form rulemaking codifies the statutory requirement of Act 13 of 2012 for secondary containment.

This cost estimate is conservative and assumes that an operator will use brand new secondary containment at every well site. According to industry secondary containment specialists, many of the secondary containment liners will be reused at multiple well sites. The Department reached out to secondary containment vendors upon finalization of the rule to ensure that cost estimates received in 2013 remained accurate. Vendors indicated that since the initial estimate, there has been nearly a 50% decrease in the cost of materials typically used for containment as well as the cost for installation of secondary containment. The Department has retained the initial cost estimate to ensure to be conservative and because material costs fluctuate based on commodity markets.

The Department estimates that the cost of providing secondary containment on an unconventional well site under 78a.64a to be $140,000.

$140,000 x 434 = $60,760,000

The total annual cost of this provision is $60,760,000.

Section 78a.64a requires materials used for secondary containment to have a coefficient of permeability not greater than $1x10^{-10}$ cm/s. This requirement effectively eliminates use of natural materials such as clay soils for secondary containment on well sites. The Department does not believe that this standard adds any significant cost over a standard that may allow for the use of natural materials. First, natural materials that are sufficiently impermeable to be effective secondary containment are not generally readily available in Pennsylvania in the areas where unconventional well development occurs. This means that materials would have to be sourced from other areas and hauled to the well site. Clay soils must also be installed in a much thicker layer than synthetic liners to provide sufficient protection which means more material must be hauled to the site adding significant hauling costs over a synthetic material. Second, the cost of installation of natural materials as a secondary containment is also significantly costlier and time consuming than synthetic materials.

When initially proposed, this provision required that the synthetic materials used for secondary containment must demonstrate compatibility with the contained fluid. Commentators pointed out that ASTM D5747 is a test for landfill liners and pits where the liner is submerged in diluted chemicals for extended period of time and the test costs around $5000 to run on each chemical type found at a site. Operators suggest ASTM D543 as an alternate test. By considering the comments, rulemaking language has been changed and the Department allows for the use of test methods if approved by the Department.

Since this is an existing statutory requirement that unconventional operators must already comply with, the total new cost of this provision is $0.

The total new cost of this provision is $0.

Site Restoration (§78a.65)

This section largely restates the restoration requirements in Section 3216 of the 2012 Oil and Gas Act and incorporates the Department's interpretation of these requirements and the existing Chapter 102 requirements as outlined in the "Policy for Erosion and Sediment Control and Stormwater Management for Earth Disturbance Associated with Oil and Gas Exploration, Production, Processing, or Treatment Operations or Transmission Facilities", Document No. 800-2100-008, which was finalized on December 29, 2012. The revisions to section 78a.65 in the ANFR were also intended to address comments on this section that indicated continuing confusion regarding what constitutes restoration as the term is used both in Chapter 78a as well as in Chapter 102, and what the associated requirements are. The changes to this section in the ANFR clarify this question and in particular distinguish between areas not restored and other areas. "Areas not restored" do not fall within the provisions in section 102.8(n) and therefore must meet the requirements, inter alia, of section 102.8(g). Areas not restored include areas where there are permanent structures or impervious surfaces.

The Department received significant comment on this provision from unconventional operators. Commenters argued that the Department failed to include any estimate for the cost associated with the new site restoration requirements. Commenters did not agree with the Department's position regarding cost savings due to the added provision of two-year extension of the restoration period. Unconventional operators estimated that the cost of well site restoration will be approximately $200,000 to $300,000 per pad; not $50,000 as Department estimated. Therefore, rather than a $21,700,000 savings, the restoration requirements are a cost of $130,000,000.

The Department does not agree with these cost estimates. The restoration requirements in this section are not new and do not impose a new cost on the regulated community as explained above. In addition, the Department disagrees with commenters' assertions that the extension requirement is merely a postponement of the cost. This section mirrors the requirements in Section 3216(g) of the 2012 Oil and Gas Act that allow operators to request to extend the restoration period for up to two years so that an operator does not have to restore the site and then disturb it again if it plans to drill additional wells on the same well pad. The cost savings associated with the restoration extension are derived from avoiding the cost of restoring the site within 9 months of completion of drilling and later having to reconstruct the site and restore it again. The Department has revised its estimate that this provision will result in $21,700,000 in cost savings. Since the 2-year extension is provided by statute, operators may be granted an extension regardless of the status of § 78a.65, the revisions to this section do not represent a cost savings for operators.

This section is intended to provide clarity for implementing existing requirements from both Act 13 and Chapter 102. To the extent that an operator would incur the costs listed above, they would incur those costs regardless of the status of § 78a.65 because they are costs associated with complying with Act 13 and Chapter 102.

The total new cost of this provision is $0.

Reporting and remediation of spills and releases (§ 78a.66)

Section 78a.66 establishes a reporting and remediation process for spills and releases that occur on well sites and access roads including a requirement to follow the procedures established under Act 2. Prior to this rule, the Department addressed spills through the policy "*Addressing Spills and Releases at Oil & Gas Well Sites or Access Roads*" which included allowances for use of an alternative process. The final rule eliminates use of the alternative process. The Department received significant public comment on this section from oil and gas operators indicating that the Act 2 process increases the cost of remediation by 3-4 times the alternative process. Commenters also noted an individual cost in which they asserted that the remediation should have only cost $10,000 but was expected to cost $250,000 due to the Act 2 process. Commenters did not provide any specific details to fully explain the estimated costs. Commenter's also argued that the timelines established for completing various steps of a spill remediation are inappropriate and overly burdensome for the oil and gas industry.

The Department does not agree with the cost estimates. The cleanup process established under § 78a.66 include the steps necessary to ensure that spills are appropriately remediated. To the extent that operators are remediating spills, they should generally be conducting the steps outlined by the Act 2 process. To the extent that operators are not conducting the steps outlined by the Act 2 process, the Department asserts that they may not be properly remediating spills. Therefore, since operators should already be conducting the required steps, the only new requirement under this rule is that operators must follow the Act 2 process in accordance with the required timelines. Since operators are required to remediate spills, the Department does not believe that the timelines established under this section represent a new cost, as commenters have noted, postponement of a cost is not an avoidance of the cost. The Department does not believe that a requirement to follow the Act 2 process represent any significant burden on the oil and gas industry.

The total cost of this provision is dependent upon the total number of spills or releases that must be reported and remediated. It is not possible for the Department to predict the number of spills or releases that will occur at well sites. Therefore, the Department is unable to provide a specific cost estimate for this provision; however, the Department does not believe that this provision represents any significant new cost to the oil and gas industry.

Borrow Pits (§ 78a.67)

Subsection 78a.67(b) require the registration of the location of existing borrow pits within 6o calendar days after the effective date of the final-form rulemaking and registration of new borrow pits before there are built. This will be done electronically through the Department's website. There were a few comments from operators that this would be burdensome on industry. The Department does not believe that the requirement to register the location of existing borrow pits with the Department represents a significant burden on the industry and has not assigned a cost to this requirement.

Subsection 78a.67(a) requires an oil and gas operator who owns or controls a borrow pit that does not require a permit under the Noncoal Surface Mining Conservation and Reclamation Act (NSMCRA) under the exemption in § 3273.1(b) of Act 13 to operate, maintain and reclaim the borrow pit in accordance with the performance standards in Chapter 77, Subchapter I and in accordance with Chapter 102.

The exemption in § 3273.1(b) of Act 13 was taken verbatim from Act 223 of 1984 or the original Oil and Gas Act. This section seeks to provide clarity for implementation of those requirements; therefore, the Department has not assigned a new cost to this requirement.

The total estimated cost of these provisions is $0.

Gathering Lines (§ 78a.68(a)-(f))

These sections establish common sense environmental controls for construction of oil and gas gathering lines. These requirements are intended to help ensure that operators maintain compliance with the Clean Streams Law, Chapter 102 and Chapter 105 when constructing gathering lines. The Department believes that most operators already comply with the bulk of these requirements and will not have to make any significant changes to their operations. The cost of these provisions is dependent on the number of linear miles of pipeline installed and the terrain in which the pipeline is installed. The Department does not have sufficient data to produce an estimated cost of these provisions but since most operators should already be in compliance with the bulk of these common sense environmental controls, the Department does not believe that this section will result in any significant burden to the oil and gas industry.

Corrosion Control for Gathering Lines (§ 78a.68(g))

The rulemaking requires that all buried metallic gathering pipelines shall be installed and placed in operation in accordance with federal statute 49 CFR Part 192, Subpart I or 195, Subpart H relating to requirements for corrosion control. Some comments received questioned the Department's statutory authority to incorporate federal standards for pipelines into the rulemaking. Section 3218.4(a) of the 2012 Oil and Gas Act provides that "[a]ll buried metallic pipelines shall be installed and places in operation in accordance with 49 CFR Pt. 192, Subpart I (relating to requirements for corrosion control)." Section 78.68(g) reflects this requirement. The incorporation of 49 CFR Part 195, Subpart H is included because that subpart also outlines standards for protecting pipelines against corrosion, specifically steel pipelines transporting hazardous liquids such as condensate from natural gas operations. The reference to 49 CFR Part 195, Subpart H is consistent with the intent to Section 3218.4(a) of the Oil and Gas Act to set forth standards for the installation and placement of metallic pipelines, including related corrosion control requirements. Since this provision is a statutory requirement, the Department has not assigned a new cost.

The total new cost of this provision is $0.

Horizontal Directional Drilling (§ 78a.68a)

This section establishes common sense environmental controls for conducting horizontal directional drilling. These requirements are intended to help ensure that operators maintain compliance with the Clean Streams Law, Chapter 102 and Chapter 105 when conducting horizontal directional drilling. The Department believes that most operators already comply with the bulk of these requirements and will not have to make any significant changes to their operations. The cost of these provisions is dependent on the number of horizontal directional bores completed and the terrain in which the bores are completed. The Department does not have sufficient data to produce an estimated cost of these provisions but since most operators should already be in compliance with the bulk of these common sense environmental controls, the Department does not believe that this section will result in any significant burden to the oil and gas industry.

Well Development Pipelines for Oil and Gas operations (§ 78a.68b)

Subsections (a) and (d)-(n) establish common sense environmental controls for constructing and operating well development pipelines. These requirements are intended to help ensure that operators maintain compliance with the Clean Streams Law, Chapter 102 and Chapter 105 when constructing and operating well development pipelines. The Department believes that most operators already comply with the bulk of these requirements and will not have to make any significant changes to their operations. The cost of these provisions is dependent on the number of well development pipelines constructed and utilized and the terrain in which the well development pipelines are constructed. The Department does not have sufficient data to produce an estimated cost of these provisions but since most operators should already be in compliance with the bulk of these common sense environmental controls, the Department does not believe that this section will result in any significant burden to the oil and gas industry.

Prohibition of buried well development pipeline (§ 78a.68b(b)-(c))

One specific requirement in this section is the requirement that well development pipelines that carry fluid other than fresh ground water, surface water, water from water purveyors or water from Department approved sources must be installed aboveground except when crossing pathways, roadways, railways, water courses or water bodies. The rule also limits the use well development pipelines to a time period of 1 year. Operators expressed significant concerns about these provisions because many operators maintain a network of buried pipelines that fit the definition of well development pipelines. Commenters did not provide any cost estimates to the Department for this provision.

The cost of these provisions is dependent on the number of pipelines that are impacted. The Department does not have sufficient data to make a detailed cost estimate but notes that the costs could be substantial.

Water management plans (§ 78a.69)

The final rule implements requirements in § 3211(m) which requires anyone who withdraws or uses water from water sources within Pennsylvania for drilling or hydraulic fracture stimulation of any natural gas well completed in an unconventional gas formation to do so in accordance with an approved water management plan.

Since this section implements existing statutory requirements, it does not represent a new cost to the oil and gas industry.

The total new cost of this provision is $0.

Monthly Waste Reporting Requirements (§ 78a.121)

The final rule includes a requirement for unconventional operators to report waste production to the Department on a monthly basis. This new rule is different from the existing requirement to report once every

6 months. The Department received significant comment on this requirement from operators indicating that it is costly and overly burdensome. Commenters estimated that waste reporting will take 20-30 hours on average regardless of the length of the reporting period. The new cost associated with this provision is the difference in the current cost to report and the new cost to report. The Department assumes a labor rate of $30/hour to do the reporting.

The current cost is between $1,200 and $1,800 per year for each operator

20 hours x $30/hour x 2 reports/year = $1,200
30 hours x $30/hour x 2 reports/year = $1,800

The new cost is between $7,200 and $10,800 per year for each operator.

20 hours x $30/hour x 12 reports/year = $7,200
30 hours x $30/hour x 12 reports/year = $10,800

The total new cost is between $6,000 and $9,000 per year for each operator.

$7,200 - $1,200 = $6,000
$10,800 - $1,800 = $9,000

The total cost of this new requirement is equal to the average new cost per operator times the number of operators.

73 operators x $6,000 = $438,000
73 operators x $9,000 = $657,000

Therefore, the total estimated annual cost of this provision is estimated to be between $438,000 and $657,000.

The estimated annual cost of this regulation on unconventional operators is between $5,895,500 and $31,149,664 with an initial cost of between $41,358,000 and $73,463,000 incurred in the first 3 years.

The Department has provided a summary table of estimated costs in Appendix A.

Conventional Operators Costs

Prior to initially proposing revisions to this rule, the Department reached out to oil and gas operators, subcontractors, and industry groups to derive the cost estimates of the final-form rulemaking. The Department received significant comment regarding the cost estimates provided by the Department when the rule was proposed. Commenters also included comprehensive analysis of their estimated costs of the proposed rule. As a result of those comments and other information, the Department made significant revisions to the final rule.

Assumptions
When initially proposing this rule, the Department estimated based on data available at the time that there will be approximately 2,000 conventional wells permitted each year for the next 3 years.

On average, about 2 out of every 3 permitted conventional wells are drilled.

There is typically only 1 conventional well per well site.

2,000 permitted wells x .667 drilled rate = 1,334 wells drilled per year

The Department received comments that this estimated number was too low. Specifically, commenters argued that the Department should base cost estimates on a projected well drilling rate of 2,750 wells per year. Since considerable time has passed since the rule was initially proposed, the Department was able reevaluate the rate at which conventional wells are permitted and drilled in Pennsylvania and include data for 2013, 2014 and the first 3 quarters of 2015.

Year	**Conventional Wells Permitted**	**Conventional Wells Drilled**
2010	**3232**	**1733**
2011	**2185**	**1271**
2012	**1564**	**1019**
2013	**1645**	**956**
2014	**1268**	**789**
2015*	**400***	**307***

***Data extrapolated from first 3 quarters (300 wells permitted, 230 wells drilled as of 9/8/2015)**

Based on the data shown in the above table which represents the most recent 5-year period in history, it is clear that the Department's estimate was, in fact, quite conservative. Conventional well drilling has been on a steady decline in recent years and the Department does not have any reason to estimate that well drilling trends will suddenly and drastically reverse course in the next 3 years. The Department does not believe that the recommended rate of 2,750 wells per year is a reasonable estimate considering the most recent data available. The Department believes that its original estimate of 2,000 wells permitted per year and 1,334 wells drilled per year is a reasonable conservative estimate of the potential conventional well drilling activity over the next 3 years.

Cost Estimates

Electronic Filing

In the final-form rulemaking, nearly all applications and notifications required by the rule are to be made to the Department electronically. Electronic reporting of production data for all operators was established by the "Oil and Gas Well Cementing and Casing" rulemaking (41 Pa.B. 805) in 2011 and is not a new requirement established by this rulemaking. **Therefore, all operators should already be registered with the Department and submitting information to the Department electronically.**

The primary new requirement in §§ 78.121 and 78a.121 is for the operator to report the specific facility or well site where waste was managed. Providing such information to the Department is a standard practice in all waste management programs and does not single out the oil and gas industry. The Department received significant public comment from conventional oil and gas operators indicating that these requirements were excessive and overly burdensome for their operations because they do not own or operate computers. Commenters estimated that this provision would cost operators $1,225 in the first year and approximately $600 per year in internet service fees after that.

If some well operators do not have a computer, it is not necessary to purchase the latest technology equipment to comply with Chapter 78 reporting requirements. There is an abundance of used computer equipment available for very modest prices. The Department of General Services routinely sends used computers to auction for nominal prices, and it surely is not the only source of used computer equipment. What many computer users would consider obsolete computer equipment would be adequate to comply with Chapter 78 reporting requirements, and there are a variety of ways such equipment can be obtained at little to no cost. In addition, the reporting requirements will not force well operators to buy expensive broadband internet access, as there are free or inexpensive dialup internet options also available in many areas. If well operators must buy and learn to use a computer to comply with reporting requirements, the equipment and skills will easily be usable for other tasks and may increase the well operators' earning potential. Well operators may want to buy more expensive computers or services than are necessary to comply with Chapter 78 reporting requirements, but any such extra costs would be voluntary.

Conventional operators are only required to report waste production from wells on an annual basis, not on a monthly basis as is required for unconventional well operators. The Department believes that the monthly reporting requirement strikes the appropriate balance between burden and benefit compared to other regulatory alternatives, such as keeping the current six-month reporting system or imposing a load-by-load manifest system as is currently required for hazardous wastes.

The Department will not assume non-compliance with existing requirements. Because operators have been required to provide production data to the Department electronically for several years, conventional operators should already have the necessary equipment and access necessary to provide electronic data to the Department. Therefore, the Department is not assigning additional costs based on the requirements of this final-form rulemaking.

New notifications to the Department

The final rule includes a number of new notification requirements. Operators must provide at least 3 days' notice to the Department prior to conducting the following activities.

- installation of pit liner (78.56)
- prior to commencing construction of a pit of greater than 250 ft^2 for servicing, plugging or recompleting a conventional well (78.56(e))
- prior to disposal of cuttings (78.61-78.63)
- prior to conducting onsite processing (78.58)
- prior to utilizing modular aboveground storage structure (78.56)
- after noticing deficiencies in tanks during monthly or quarterly inspections (78.57(h))

The Department received comments from conventional operators that these notification requirements will add costs of up to $10,000 per well due to the resulting delays. The Department disagrees with this estimate. The notification requirements are structured in a manner to allow significant flexibility in the timing. In addition, the Department believes that if operators know the requirements and plan accordingly, the requirement to make these notifications should not ever result in any delay for operations.

The total new cost of this provision is $0.

Identification of Public Resources (§ 78.15)

The requirements in this section ensure that the Department meets its constitutional and statutory obligations to protect public resources.

The Department received significant public comment on these provisions from conventional gas well operators. Commenters disagreed with the Department's estimates of cost for permit conditions to protect public resources. Commenters argued that coordination with public resource agencies to consider impacts to other critical communities will impose an economic hardship on conventional oil and gas operators. The Department disagrees because operators are currently required to identify the habitats of special concern species where the proposed well site or access road will be located and describe measures proposed to be taken to avoid or mitigate impacts to special concern species. The applicant must provide a PNDI receipt with the well permit application and, if a potential impact to a special concern species is identified, the applicant must notify the applicable public resource agency. The applicant should also be consulting with the agency to identify appropriate avoidance and/or mitigation measures. As this is an existing well permit application component necessary to comply with the Department's constitutional and statutory obligations, the requirement to consider impacts to other critical communities in final rulemaking does not impose any new financial burden.

The first step in the process is identification. The Department believes this t process would be required for all new well sites. First an electronic review can be conducted with the Pennsylvania Conservation Explorer's online planning tool. This tool will allow operators to identify the location of the majority of public resources which require consideration under the final rule. This tool also will allow the operator to identify potential impacts to threatened and endangered species, which also must be addressed under § 78a.15(d). Since the tool may not have data to identify all the public resources listed in Section 78a.15(f)(1), operators will also need to conduct a field survey of the proposed well site area to identify public resources. The Department estimates the cost of the field survey to be $500 and the cost of the electronic survey to be $40. Even though use of the online tool is required to comply with requirements protecting threatened and endangered species, the Department has included the cost in this estimate nonetheless.

$500 x 1,334 = $667,000
$40 x 1,334 = $53,360

$667,000 + $53,360 = $720,360

The second step of the process is consultation with the public resource agency. This process is only applicable to well sites which are within the prescribed distances or areas listed in Section 78.15(f)(1). The Department estimates that 30% of well sites will fall within these distances or areas. Operators will be required evaluate the functions and uses of the public resource, determine any probable harmful impacts to the public resource and develop any needed mitigation measures to avoid probable harmful impact. Operators must also notify potentially impacted pubic resource agencies of the impact and provide those public resource agencies the same information provided to the Department. Cost of the provision is dependent on the number of well sites impacted as well as the complexity of evaluating the functions and uses of the public resource. The Department estimates the postage will cost $20 per notification to public resource agencies.

$20 x 1,334 x 30% = $8,004

Due to the complexity of the variables in this process, the estimate for the cost of evaluating the functions and uses of the public resource and determining whether there is a probable harmful impact will vary. In some cases, functions and uses of the public resource and any probable harmful impacts may be immediately obvious and others may be far more complex and may include multiple public resources.

The final step in the process is mitigation. The cost estimate for mitigation will vary. In some circumstances, an operator may be able to plan the location of the well site using the planning tool discussed above to avoid public resources resulting in zero cost. Any cost associated with mitigation measures is dependent on many variables and may be situation specific in some cases. While the Department is unable to provide a specific estimate for the implementation of this entire provision, it should be noted that this cost may be substantial depending on the location of the well site.

$720,360 + $8,004 = $728,364

The total cost of this provision is $ $728,364 *(not including consultation and mitigation).*

Protection of water supplies (§ 78.51)

This section provides the Department's interpretation of the water supply restoration and replacement in Section 3218(a) of the 2012 Oil and Gas Act.

Conventional operators argued that the provision in Act 13 should be interpreted to mean that impacted water supplies must be restored to Pennsylvania Safe Drinking Water Act standards or previous water quality, whichever is poorer.

Conventional operators provided estimates that this provision will result in new costs ranging from $825,000 and $61,000,000 per year. The Department notes that given the need to provide replacement water based on the positive impact determination under either interpretation, the additional cost borne by operators is limited to the incremental cost of providing Pennsylvania Safe Drinking Water Act standards water as compared to the previous poor quality, not the difference between providing no water at all and meeting Pennsylvania Safe Drinking Water Act standards. Commenters did not provide a detailed explanation of how these estimates were derived so it is not clear to the Department if this fact was considered when developing this cost estimate.

This section seeks only to provide clarity to existing statutory requirements. Accordingly, the estimated new cost incurred by unconventional operators is $0.

The Department acknowledges that if § 3218(a) of Act 13 is interpreted in the way conventional operators believe to be appropriate, costs incurred by operators are likely to be lower than what the statute currently requires.

The total new cost of this provision is $0.

Area of Review and Monitoring Plans (§§ 78.52a and 78.73)

This provision will affect each well drilled and stimulated using hydraulic fracturing.

The Department estimates area of review will cost $450 per each well.

$450 x 1,334 wells = $600,300

The total cost of this provision is $600,300.

Conventional operators submitted comments stating that they do not agree with the Department's 2013 assessment related to the area of review implementation costs. The industry feels that this section imposes a significant cost since operators are required to compile reports and possibly gain access to surrounding properties to conduct surveys. It has been stated that the surveyor's time to draw a well site map will increase from one day to as much as a week to collect the information and develop a plan covering 72 acres, raising current site map costs from $500 to $2500. If the surveyor has to provide the plat with GPS information, an additional cost of $1000 may be added to the total cost. The following summary table, which has been slightly modified from its original format, includes costs provided by the Pennsylvania Independent Petroleum Producers during the public comment period.

Subsection	Task	Description	Maximum Industry Cost Per Well
(b)(l)	Database Review	Operator must review Department databases. Make appointment. Travel 1-3 hours each way to Regional Office. Review database for 1-3 hours.	$500
(b)(2)	Historical Review	Operator must hire expert to research historical sources of information, such as farm line maps	$1,500
(b)(3)	Landowner Questionnaire	Operator must submit DEP questionnaire (does not yet exist) to landowners regarding location of abandoned and orphaned wells	Unknown

(c)(1)	Plat	Operator must submit a plat showing the location and GPS coordinates of all wells identified in (b).	$700
(c)(2)	Proof of Notification	Operator must submit proof that questionnaires submitted under (b)(3)	$30
(c)(3)	Monitoring Plan	Operator must submit plan for monitoring wells required under 78.73(c). Installation of monitoring tank may be required	$2,700
(c)(4)	Well Depth	Operator must submit true vertical depth of wells, if known	Unknown
(c)(5)	Source of Information	Operator must identify source of information for identified wells, if available.	Unknown
(c)(6)	Well Integrity	Operator must furnish surface evidence of failed well integrity, if available.	Unknown

Although conventional operators are required to comply with this section, it is anticipated that costs will be insignificant in comparison to potential liabilities associated with a hydraulic fracturing communication incident. Plats, which are currently required for all well sites, must be prepared by a competent engineer or surveyor in accordance with Section 3211(b) of Act 13. However, only the well sites requiring monitoring under Section 78.73 must field verified and surveyed. Although professional surveying firms are commonly employed by the unconventional industry, this is not required as indicated in Section 3211(b) of the Act. Further, existing law under Section 3213(a.1) has required operators to identify all abandoned assets discovered on their leases to the Department for many years. The low-end cost for GPS units with sub-meter accuracy is $500, which could be amortized over many years of use. For an operator drilling ten (10) new wells per year, the cost would equate to $50 per well if a new GPS unit was purchased each year. If a professional surveying firm is hired, it is anticipated that the costs will be a fraction of those associated with unconventional sites due to the smaller surveyed area. An estimate of $250 is based on conversations with professional surveying companies and a proportionally reduced survey area of 1,000 feet by 1,000 feet.

Costs associated with the review of the Department's databases and historical maps have been estimated at $2,000 by the industry. Many of these sources are available free of charge and can be accessed online. Amortizing the purchase of a new computer ($500) and a web connection ($360) for ten wells drilled results in a per-well cost of approximately $90. However, since electronic reporting requirements having been in place for several years for production and waste, the Department estimates this cost should be $0 for most conventional operators in good compliance standing.

Because of the smaller footprint associated with the area of review for conventional operators, the Department believes that periodic offset well site inspections will be a cost-effective strategy in most cases, with some sites requiring rental of a poly tank for fluids management/containment. This along with reporting costs may push the per-well cost up another $225, which is inclusive of potential consulting fees and tank rental costs. Conservatively, the total cost estimate per well for operators not currently completing due diligence to perform this task is not expected to exceed $450 per well site on average.

For comparison, the Department recently summarized costs associated with two (2) hydraulic fracturing communication incidents. Responding to and addressing these incidents, which occurred at conventional well sites, resulted in costs of $280,000: $50,000 for remediation services and $230,000 for well plugging activities. Such costs are expected to increase substantially in situations where water supplies are impacted by migrating methane gas or when adjacent gas wells must undergo repairs. The company providing this information has indicated that these communication incidents could not have been avoided even with the new requirements in place. The Department acknowledges that in certain cases, even with the implementation of the regulation and the application of best practices, that some percentage of communication incidents will still take place. However, it adds that this regulatory concept is being addressed and acknowledged by a number of other regulatory programs, the STRONGER organization and API, a globally recognized industry trade organization.

Site Specific Prevention and Contingency Plan (PPC) Plans (§ 78.55)

The final rule requires all oil and gas operators to develop and implement a site specific PPC Plan under §§ 78.55 and 78a.55. The Department received significant public comment from conventional oil and gas operators indicating that this requirement was excessive and overly burdensome for their operations. The commenters argued that the requirement to develop and update site specific PPC plans is unnecessary because conventional well sites are all so similar that a single plan is sufficient to address all sites. The commenters also argued that maintaining a copy of the PPC plan on the site is overly burdensome and unnecessary for conventional operators. Commenters also expressed concerns about §§ 78.55(a) and 78a.55(a) which simply reiterate the requirements already existing in Chapters 91.34 and 102.5(l). Because §§ 78.55(a) and 78a.55(a) do not establish any new requirements, the Department does not believe that this subsection presents any new burden on operators and no cost was attributed with these provisions.

Commenters estimated 200,000 discrete well and tank locations which would require a PPC plan under the final rule. Commenter's estimated costs of $40 for purchasing PPC plan storage units with $25 in labor to install each unit. Commenters also estimated $100 to prepare each plan if the preparation is done in house and $500 if the preparation is done by a contractor. Commenters also estimated that PPC plans would have to be updated annually, even though it is not required by the rule and that each PPC plan storage unit would require repairs each year. The total cost of the updates and the repairs was estimated to be $125/plan. Commenters did not provide a breakout of the estimated update and repair costs. Overall the total cost of this requirement is estimated by commenters from the conventional industry to be over $125,000,000. The Department does not agree that this is a reasonable cost estimate.

First, the requirement for operators to develop a control and disposal plan or PPC plan has been in existence under § 78.55 since 1989 when Chapter 78 was first promulgated. A plan that does not address the specific needs of a site could not and should not be considered to meet the requirements of § 78.55. Therefore, in order for conventional operators to ensure that they were in compliance with the planning requirements in § 78.55, they must have been evaluating their PPC or control and disposal plans against site specific conditions since 1989. In addition, it is not the intent of this rulemaking nor is it required by this rulemaking that each PPC plan developed for a different well site must be unique. Therefore, the Department does not believe that the costs estimates by conventional operators of $500 to prepare each plan are reasonable. Instead, the Department estimates the new cost associated with this requirement to be negligible because operators have been required to develop these plans since 1989.

It is also not the intent of this rulemaking to ensure that all PPC plans are revised annually. There are no specific review and update timeframes included in the rulemaking. The rule requires revisions to the plan in the event that practices change. Therefore, if conditions at the site do not change, there will be no need to make revisions to the PPC plan. In addition, operators have been required to revise their plans under these same conditions since Chapter 78 was initially promulgated in 1989. Therefore, there is no new cost attributed to this provision.

Finally, it appears that the commenters incorrectly assumed that every single site where activities including the impoundment, production, processing, transportation, storage, use, application or disposal of pollutants must have the PPC Plan posted on site at all times. The rule does not include this requirement or anything resembling this requirement. In fact, the rule does not require the PPC plan to be maintained on the site at all. The Department believes that it is prudent for operators to maintain the PPC plan on the site when the site is active including, drilling, alteration, plugging or other activities where there is an increased risk of a spill, release or other incident, but it is not required by § 78.55. Therefore, there is no new cost attributed to this requirement.

The total new cost of this provision is $0 (negligible).

Providing copies of the PPC plan to the landowner and PA Fish and Boat Commission (§ 78.55)

The final rulemaking includes a requirement for operators to provide copies of the site specific PPC plan to the Pennsylvania Fish and Boat Commission and the landowner upon request. The cost associated with this requirement depends on the number of plans that are requested. If no plans are requested, there is no cost associated with this requirement. If the landowner and the Pennsylvania Fish and Boat Commission request the plan for every well site, the Department estimates the cost to be $66,700.

1,334 x $25 x 2 = $66,700.

The total new annual cost of this provision is estimated to be $66,700.

Tank Valves and Access Lids Equipped to prevent unauthorized access by third parties (§ 78.56(a)(6))

When originally proposed, § 78.56(a)(6) addressed security requirements for pits, tanks and approved storage structures and required operators to equip all tank valves and access lids to regulated substances with reasonable measures to prevent unauthorized access by third parties such as locks, open end plugs, removable handles, retractable ladders or other measures that prevent access by third parties. The Department received significant public comment from conventional operators indicating that the costs associated with equipping pits, tanks and approved storage structures with the prescribed security measures would be exorbitant for the conventional industry which currently employs approximately 175,000 tanks. Commenters estimated the total cost of this provision to be $600,000,000 for installation of security measures on existing tanks and $6,300,000 annually for increased labor costs due to inefficiencies caused by the security measures on well sites. For new sites, commenters estimated the cost of compliance to be $500/tank with one tank for every 2 wells.

The Department agreed that changes to § 78.56 to remove the requirement to install equipment to prevent unauthorized access by third parties are appropriate for conventional operations.

The Department initially estimated the total cost of this provision to be between $53,600 and $6,670,000 but since this provision has been eliminated, the total cost is $0.

The total new cost of this provision is $0.

Minimum 30 mil liner thickness unless thinner material is demonstrated to be equally protective (§ 78.56(a)(8))

The final rule requires that pit liners for temporary storage have a thickness of at least 30 mils and allows for the liner manufacturer to demonstrate that a thinner liner is equally protective. Prior to this revision, § 78.56 did not include any specification for minimum liner thickness and only included a requirement for a "synthetic impermeable liner." However, § 78.62 relating to disposal of residual wastes in a pit has required the use of a 30 mil liner or an alternate material if approved by the Department since Chapter 78 was initially promulgated in 1989. The Department acknowledges that when disposing of cutting by land application, a liner thickness is not specified but the Department notes that disposal of cuttings in a pit is far more common than land application. The Department has approved a number of liner products with a 20 mil thickness since Chapter 78 was initially promulgated but does not believe that the exception should define the rule. Due to these requirements, the Department believes that conventional oil and gas operators should already using 30 mil liners or an approved alternative most of the time.

The Department received comments on this provision stating that it was unnecessary and would increase costs of pit liners by over 100%. The comments specifically suggested that the price of a pit liner for a conventional operator would increase from $915 to $1864 if a 30 mil liner was required. The commenter did not provide detailed specifications for the liner described but it was indicated that the pits used in conventional well operations are typically no larger than 10 feet by 30 feet and hold less than 4,200 gallons. The liner required for a pit of that size is conservatively 650 ft^2. Based on liner pricing data available to the Department, the commenter is clearly not basing the cost estimates of $915 for 20 mil and $1,864 for 30 mil on what the commenter describes as a typical pit used in conventional well operations. In fact, the cost data appear to the Department to be based on providing a liner for a much larger pit, possibly as large as 6,000 ft^2 or 9 times the area of a pit identified by the commenter to be typical. A pit requiring a liner of 3,800 ft^2 size has been represented to the Department by the Conventional Oil and Gas Advisory Committee (COGAC) as the largest pit used during conventional operations in Pennsylvania. The Department believes that the example given by the commenter is an extreme example and is therefore not an accurate representation of the impact of a 30 mil liner requirement on the conventional oil and gas industry.

The Department did not initially assign a cost to this change in the regulatory analysis form developed for the proposed rulemaking. The following cost estimate is based on the cost difference between 20 mil and 30 mil liners. The Department acknowledges that operators may have bene using liners thinner than 20 mil in some cases but the Department does not believe that liners thinner than 20 mil generally have sufficient strength and thickness to maintain the integrity of the liner. Therefore, liners thinner than 20 mil were not considered. In order to provide a cost estimate, the Department reached out to a number of Pennsylvania based liner suppliers for pricing data. The most expensive provider quoted a price of $0.24/ft^2 for 20 mil HDPE and $0.40/ft^2 for 30 mil HDPE. For a typical conventional pit this amounts to a cost difference of $104. This price includes material costs only because install costs for both materials is equivalent.

650ft^2 x ($0.40-$0.24) = $104

The Department estimates that conventional operators dispose of drill cuttings in a pit about 75% of the time. Since operators that are using pit disposal are already required to use a 30 mil liner or an approved alternative, as has been the case since 1989, this new provision does not represent a new cost to 75% of new wells drilled. In addition, this provision is not written in a manner to require retroactive application so no cost is assigned to pits existing prior to promulgation of the rule.

$104 x 1,334 x 25% = $34,684

The total new cost of this provision is estimated to be $34,684 per year.

Minimum pit slope of 2:1 or flatter (§ 78.56(a)(9))

When originally drafted, the Department included a requirement that temporary pits must have an inside slope 2:1 (horizontal: vertical) or flatter. The Department received significant public comment on this proposed requirement indicating that typical conventional pits use vertical walls and that this provision would require a significant deviation from typical practice. The Department did not initially assign a cost to this provision but commenters from the conventional industry estimated the additional cost to be between $5,000 and $25,000 per well, depending on topography. This would result in a total cost increase of between $6,670,000 and $33,350,000.

As a result of these comments, the Department ultimately removed the minimum slope requirement from the final rulemaking. Instead, the final rule continues to allow conventional operators to construct pits with steep inside slopes provided that the pits have an aerial extent of less than 3,000 ft^2 and volumetric capacity of less than 125,000 gallons. A pit of this size has been represented to the Department by the Conventional Oil and Gas Advisory Committee (COGAC) as the largest pit used during conventional operations in Pennsylvania. For larger pits, the rule requires the operator to obtain a site specific approval from the Department prior to constructing the pit. This revision will allow continued use of conventional pits at well sites, prevent an unnecessary increase in the footprint of pits and provide appropriate protections to the environment when operators require the use of large pits.

As a result of these revisions, the estimated cost increase for typical conventional operations is $0.

For pits larger than the thresholds described above, the total additional cost is anticipated to be negligible because pits of this size are rarely used by the conventional industry.

The total new cost of this provision is estimated to be $0.

Inspection of pit liner prior to utilizing pit to store waste (§ 78.56(a)(12))

This section requires conventional operators to inspect pit liners and repair all damages or imperfections prior to placing material in the pit. This is a new requirement which the Department estimates will take 1 hour of work time to complete if the liner is not damaged. There is no required paperwork associated with this requirement. The Department acknowledges that more work time will be necessary to comply in the event that a liner is found to be damaged but has not associated costs with repairs because repairs are necessary to comply with many other long-standing provisions in § 78.56 including § 78.56(a)(8)(i) which requires the liner to have a very low permeability and § 78.56(a)(8)(iv) which requires sections of the liner to be sealed together to prevent leakage.

The Department assumes that each well will have 1 pit liner to inspect at a labor rate of $30/hr. and that this provision will not be applied retroactively

1,334 x 1 hour x $30/hr. = $40,020

The total cost of this provision is estimated to be $40,020 per year.

Secondary Containment for all aboveground structures holding brine or other fluids (§ 78.57(c))

When the rule was proposed, the Department estimated the cost to add secondary containment for all aboveground structures holding brine or other fluids to be $4,002,000. This estimation assumed 1 secondary containment structure per well and estimated a cost of $3,000 per containment structure.
$3000 x 1,334 = $4,002,000

Commenters correctly pointed out that the rule also requires secondary containment to be installed for all replaced and refurbished tanks as well as new. Commenters from the conventional industry estimated that tanks are refurbished or replaced at a rate of 7.5%/year. Based on an estimated 150,000 aboveground storage tanks in service, this equates to a refurbishment and replacement rate of 11,250 tanks/year. The commenters also estimated that 50% of the refurbished or replaced tanks will require new containment. The Department presumes these estimates to be accurate. Using these estimates, the updated cost of compliance is $20,877,000

$3000 x 1,334 = $4,002,000

150,000 x 0.075 x 0.5 x $3,000 = $16,875,000

$4,002,000 + $16,875,000 = $20,877,000

The total cost of this provision is estimated to be $20,877,000 per year.

Identification of Underground Storage Tanks (§ 78.57(e))

When initially proposed, the rule prohibited the use of underground or partially buried storage tanks for storing brine. Under the proposed rule operators would have 3 years to remove all existing underground or partially buried tanks. The Department's initial cost estimate did not attribute a cost to this provision because the cost was dependent on the number of buried tanks across the Commonwealth and the Department was unable to estimate the number of buried tanks at that time. This section also required operators to provide a list of all affected tanks to the Department within 6 months of when the rule became final. The Department estimated the cost to provide a list of all affected tanks to the Department within 6 months of the rulemaking becoming final to be $20,000.

The Department received significant public comment on this provision from conventional oil and gas operators. The Department received numerous estimates of the number of existing underground or partially buried storage tanks ranging from 2,000 to 150,000. Conventional operators argued that with potentially 150,000 buried tanks the cost to remove each tank and the cost to replace tanks that will be damaged in the removal process was significantly greater than the Department had considered when drafting the Rule. In addition, operators indicated that the act of burying tanks is done to provide freezing protection for produced waters in the winter and to allow water and oil to be more easily separated. As a result of public comment, the Department has amended the final rule to allow the use of buried tanks by both conventional and unconventional well site operators and does not require removal of existing buried tanks. The Department continues to believe that underground storage tanks warrant extra scrutiny because they are not as easily inspected and can provide a more direct conduit for contamination into groundwater and therefore has included provisions in the final rule to require the location of all existing and any new underground storage tanks at well sites to be reported to the Department. Therefore, the original estimate of $20,000 is retained. The Department does not believe that there will be any significant new cost associated with notifying the Department of newly installed underground or partially buried tanks.

The total cost of this provision is estimated to be $20,000

Corrosion protection for permanent aboveground and underground tanks (§ 78.57(f)-(g))

Subsections 78.57 (f)-(g) implement Section 3218.4(b) of Act 13 which establishes that permanent aboveground and underground tanks must comply with the applicable corrosion control requirements in the Department's storage tank regulations. Commenters argued that this requirement is too costly to comply with and estimated a total cost to provide corrosion protection to all 175,000 existing tanks to be approximately $224,525,000. The commenters did not provide a specific cost breakdown for how that cost was derived.

The Department does not agree with the cost estimate. First, the estimate assumes that all existing tanks that are currently utilized by the conventional oil and gas industry are in need of cathodic protection and corrosion protection. This assumption is false because it is common for the conventional oil and gas industry to utilized plastic tanks which do not require corrosion protection to meet these requirements. Second, the final rule does not require retroactive application of the corrosion control requirements. Only new, refurbished or replaced aboveground and underground storage tanks must comply with the applicable corrosion control requirements. So to apply the projected costs to all existing tanks is not an accurate portrayal of the true cost of this provision.

Additionally, it is common knowledge that steel structures, including storage tanks, corrode or rust and fail when left unprotected and exposed to the elements. It is also common knowledge that brine or salt water which is commonly stored in tanks at conventional well sites increases the rate of corrosion of steel. Given these facts and considering that the estimated cost for replacement tanks is significantly higher than the estimated cost for providing corrosion protection for those same tanks (see table below, the estimated costs for providing corrosion protection is less than half the cost of a new tank), the Department believes that it would behoove conventional oil and gas operators to provide corrosion protection for their tanks because it can extend the useful life of the tank significantly at a fraction of the cost of replacing the tank. In fact, this provision may represent a cost savings to operators that had previously not been maintaining their tanks appropriately.

Size(bbl)	Current Cost	Cathodic Protection	Corrosive Protection	Ratio of Cost of Corrosion Protection to Replacement
25 bbl.	$1,800.00	$350.00	$450.00	0.44
50 bbl.	$2,200.00	$350.00	$650.00	0.45
100 bbl.	$3,451.00	$350.00	$1,200.00	0.45
140 bbl.	$5,144.00	$350.00	$1,300.00	0.32
210	$6,083.00	$350.00	$1,600.00	0.47

Finally, this requirement is a statutory requirement under section 3218.4(b) of Act 13. As noted above, subsections 78.57(f)-(g) simply implement this requirement. The Department has also explicitly removed the requirement to use Department certified inspectors to conduct inspections of interior linings or coatings which will alleviate some burden on oil and gas operators. Operators may choose to use non-metallic tanks which can often be less expensive than steel equivalent and do not require any additional cost to ensure protection from corrosion.

Since this section implements existing statutory requirements no cost is assigned to this provision.

The estimated new cost of this provision is $0.

Quarterly Maintenance Inspections (§ 78.57(h))

Sections 78.57 and 78a.57 impose a new requirement for operators to conduct periodic inspections of tanks used to control and store production fluids on a well site and document each inspection. The Department initially proposed that all inspections should be conducted monthly, which the same frequency as required by the Department's storage tank regulations. In response to comments, the Department has amended subsection 78.57(h) to reduce the frequency of inspection from once per calendar month to once per calendar quarter to allow coordination between tank inspections and mechanical integrity assessments required under § 78.88 which requires wells to be inspected on a quarterly basis. This change will have the effect of reducing the burden on conventional operators while ensuring that storage tanks for produced fluids on well sites are inspected periodically. The Department received significant public comment on this requirement from conventional oil and gas operators indicating that this requirement would impose significant cost burdens on the conventional industry. Commenters estimated that inspection of each tank would take 1 hour on average at a labor rate of $30/hr. Commenters estimate that there are approximately 175,000 tanks utilized by conventional operators resulting in a total estimated annual cost for monthly inspections of $63,000,000 and $15,750,000 for quarterly inspections. The Department disagrees with this cost estimate.

The quarterly maintenance inspection is intended to be a visual check of the tank and containment area to ensure that the tank and containment structures are in good working condition and that ancillary and safety equipment are in place and in good working condition. The Department estimates that on average, inspection of each tank, including filling out the inspection form will take 15 minutes, resulting in a total annual cost of $5,250,000.

175,000 tanks x 4 inspection x $30/hr. x 0.25 hrs. = $5,250,000

The Department believes that periodic inspections are appropriate common sense accident prevention steps that every storage tank operator should follow. In addition, it is almost always less costly to prevent an accident than to remediate the harm that is caused when an accident occurs. Remediation of a single spill could cost more the total annual cost to inspect all storage tanks utilized conventional oil and gas well operators.

The estimated new annual cost of this provision is $5,250,000.

Radiation Protection Action Plan (§78.58 (d))

The Department has added 78.58(d) to this rulemaking which requires an operator processing fluids onsite to develop a radiation protection action plan which specifies procedures for monitoring and responding to radioactive material produced by the treatment process. This section also requires procedures for training, notification, recordkeeping, and reporting to be implemented. This section does not require review or approval by the Department prior to implementation of the plan. In addition, the Department does not believe that a new or unique plan must be developed for each individual well site where processing occurs. Many operators will probably find that a single plan developed under this provision is applicable to processing operations over large geographic areas.

The Department does not believe that this provision will result in any significant new cost to conventional operators because conventional operators do not generally conduct processing on well sites.

To the extent that a conventional operator does conduct processing under § 78.58 and is required to develop a radiation protection action plan, the Department estimates that development of a plan will cost $10,000. The Department also believes that the majority of conventional operators would need only one plan to cover their operations. The total cost of this provision is dependent on the number of operators that conduct onsite processing and require development of a radiation protection action plan. The Department does not expect typical conventional operators to conduct onsite processing which would require development of such a plan but acknowledges that some number of operators may wish to conduct such activities.

The estimated total cost for this provision is $0 for typical conventional operations

Well Development Impoundment Construction Standards (§§ 78.59a, 78.59b)

In the final rule, §§ 78.59a and 78.59b impose construction and operation standards for well development impoundments including embankment construction standards, the need for surrounding well development impoundments with a fence and providing an impermeable plastic liner. The Department received comments from conventional operators indicating that these requirements were too expensive to comply with and would result in conventional operators being required to close existing impoundments at great expense for no environmental benefit. Commenters presumed that conventional operators would not be able to meet the requirements and would have to abandon all of their existing well development impoundment. Commenters then estimated that in the absence of well development impoundments, the additional cost of trucking water would cost $1,000 - $1,500 per well and that costs would be imposed on approximately 10% of wells drilled. This equates to a total new cost of $133,400-$200,100 per year for new wells. In addition, commenters noted that existing wells still have some need for freshwater and estimated that without use of well development impoundments, the new cost to be $100,000 per year for a total cost of $233,400 - $300,100 per year. One commenter estimates that 1,000 well development impoundments are currently operated by conventional operators and all would have to be closed a cost of $12,500 per impoundment for a total cost of $12,500,000. The Department does not agree with these estimates.

The Department does not believe that the majority of the ponds would be regulated under these provisions, as stated by one commenter. The same commenter describes these ponds as "*a freshwater source only, and no liquids are returned to or placed in the pond, other than groundwater. The ponds are traditionally small—on average a few dozen feet in width and ten or twelve feet in depth. The ponds have the same character as the many farm ponds that dot the landscape, and in addition to serving the above functions the ponds provide the recreational and wildlife benefits that any other small farm pond would, including fish and animal habitat.*" Based on this description these ponds seem to be better described as water sources than well development impoundments. To the extent that operators are constructing collection or intake dams for water sources, it is not the intent of the final rule to regulate those structures as well development impoundments. Based on the information provided by commenters, the Department believes that, at most, only a very small fraction of the 1,000 existing structures commenters interpreted to be well development impoundments will be impacted by the rule.

The cost associated with this provision is dependent on the number of existing facilities impacted. In order to develop a conservative cost estimation, based on the descriptions and information provided by conventional operators, the Department assumes that less than 5% of the 1,000 structures meet the description of well development impoundment and would be closed at a cost of $12,500 per impoundment.

1,000 x 5% x $12,500 = $625,000

It is also very likely that no existing facilities are impacted, in which case the cost is $0.

In addition, since at least 950 of these ponds will remain, the Department estimates that the costs associated with servicing existing wells will be reduced to $5,000 per year. The Department has not assigned a cost to future construction of new well development impoundments because conventional operators have indicated that they will not construct them.

Finally, the rule also requires operators to register the location of well development impoundments with the Department. Assuming a total of 50 existing well development impoundments, the Department estimates a total cost of $4,500.

The total cost of this provision is estimated to be between $0 and $634,500 for the first year and between $0 and $5,000 annually thereafter.

Centralized Impoundment Requirements (§ 78.59c)

The final rule requires conventional operators to close any existing centralized impoundments within 3 years of the implementation date of the final rule or obtain a permit from the Department's waste management program in the same time frame. The rule also requires any new centralized impoundment to be permitted by the waste management program. The cost of this rule is dependent upon the number of centralized impoundments that are impacted. No conventional operators currently hold permits for any centralized impoundments so to the extent that a conventional operator has a centralized impoundment, they are operating unlawfully. In addition, the Department does not anticipate conventional operators to construct any new centralized impoundments in the future.

The total new cost of this provision is $0.

Verifying that the bottom of the pit is 20" above the seasonal high groundwater table (§ 78.62(a)(9))

Section 78.62(a)(9) (relating to disposal of residual wastes – pits) requires operators to determine that the pit meets this requirement prior to using the pit. The determination must be made by a soil scientist or other similarly trained person using accepted and documented scientific methods. The Department notes that the rule does not exclusively require this determination to be made by a soil scientist but instead it allows the determination to be made by a soil scientist or other similarly trained person. The Department believes that training can be provided to conventional oil and gas operators to ensure they have the skills necessary to accurately identify the seasonal high groundwater table and comply with this requirement without having to hire a professional soil scientist in all cases. In addition, since 1989, in order to ensure that they were in compliance with this requirement, conventional operators must have been conducting an evaluation of the soils beneath the bottom of their pit locations.

To develop a cost estimate for this provision the Department will assume that all conventional well sites utilize a pit. However, this assessment is only required when the operator will dispose of residual wastes on a pit and is not required when the operator disposes of residual wastes off site or by land application. The Department attempted to use waste reporting data required under § 78.121 as a basis for the determination of how operators dispose of drill cuttings but found the available data to be lacking due to non-compliance with reporting requirements by conventional operators. Since data available to the Department is not representative of field practices, the Department will rely on field experience along and estimate that cuttings are disposed in a pit 75% of the time.

The cost of this provision ranges based on whether the operator obtains training and makes the determination in house or hires an outside consultant to make a determination.

In House Determination

It is the intent of the Department to provide training to operators to allow them to meet the requirement of being a similarly trained person. Since, as described above, the only new requirement is to verify and document that the bottom of the pit is 20" above the seasonal high groundwater table and operators must have been conducting investigations since 1989, no additional work time is assigned to the investigation. Therefore, the only new burden associated with this provision is the time spent filling out the form to document the determination. The Department estimates this should take 15 minutes to complete. The Department is using the labor rate provided by the conventional industry when calculating the cost of completing this work.

1,334 x 0.75 x 0.25hrs x $30/hr. = $7,504

Outside Consultant

If an operator chooses not to or is unable to obtain training, they may hire an outside soil scientist to conduct the investigation and complete the paperwork. Since, as described above, the only new requirement is to verify and document that the bottom of the pit is 20" above the seasonal high groundwater table and operators must have been conducting investigations since 1989, no additional work time is assigned to the earthwork required for the investigation. Therefore, the only new burden associated with this provision is the time spent by the soil scientist for conducting the investigation and filling out the form to document the determination. The Department estimates the cost to hire a soil scientist to be $750-$1,000 per day. With proper planning, operators would be able to utilize the soil scientist for the entire day to do multiple determinations. The Department estimates that a soil scientist would be able to complete 4 determinations on average, including paperwork in the time allotted. This estimate takes into account the fact that conventional well pits are typically no larger than 10 feet by 30 feet and hold less than 4,200 gallons. A pit of this size has a depth of approximately 2 feet and would necessitate digging a pit to a depth of only 3 feet, 8 inches to ensure the season high groundwater is 20 inches below the bottom of the pit. Digging to this depth is generally very easy to accomplish with earth moving equipment commonly used by conventional operators.

In addition, since the regulation allows for the use of other similarly trained people, an operator may hire an outside consultant that is not a professional soil scientist but is appropriately trained to meet the requirements at a lower rate. For example, many local sewage enforcement officers are appropriately trained to meet these requirements but do not command the pay rate of a professional soil scientist. Conservatively, the Department estimates that other similarly trained people are available for hire for $750 per day or less.

The cost of this provision varies depending on how efficiently consulting services are utilized. If professional soil scientists are hired at a daily rate and used to make only 1 determination the cost is estimated to be $1,334,000.

1,334 x 0.75 x $1,000 = $1,000,500

If a consultant is hired at a daily rate and used to make multiple determinations, the cost would be reduced. The Department believes that 4 determinations in a day is a reasonable conservative estimate.

(1334 ÷ 4) x $750 x 0.75= $187,594

The total annual cost of this provision if an outside consultant is hired is estimated to be $187,594-$1,000,500.

The total annual cost of this provision is estimated to be $7,504-$1,000,500.

Alternative Waste Management (§ 78.63a)

This section seeks to codify the existing practice of requiring approval for alternative waste management practices. There is no cost associated with this section.

The total new cost of this provision is $0.

Site Restoration (§ 78.65)

This section largely restates the restoration requirements in Section 3216 of the 2012 Oil and Gas Act and incorporates the Department's interpretation of these requirements and the existing Chapter 102 requirements as outlined in the "Policy for Erosion and Sediment Control and Stormwater Management for Earth

Disturbance Associated with Oil and Gas Exploration, Production, Processing, or Treatment Operations or Transmission Facilities", Document No. 800-2100-008, which was finalized on December 29, 2012. The revisions to § 78.65 in the final-form rulemaking were also intended to address comments on this section that indicated continuing confusion regarding what constitutes "restoration" as the term is used both in Chapter 78 as well as in Chapter 102, and what the associated requirements are. The changes to this section in the ANFR clarify this question and in particular distinguish between areas not restored and other areas. "Areas not restored" do not fall within the provisions in section 102.8(n) and therefore must meet the requirements, inter alia, of section 102.8(g). Areas not restored include areas where there are permanent structures or impervious surfaces.

The Department received numerous comments from conventional operators on this section indicating that it is inappropriate and would impose new costs on the conventional operators that are so enormous that they would put small, independent well operators out of business. Commenters estimated the total new cost of this section to be $22,000-$84,000 per well pad. A cost breakdown is provided below.

- Engineering services to prepare PCSM Plan satisfying §102.8(g): $10,000 - $15,000.
- Engineering services to prepare NPDES Permit application: $2,000 - $5,000.
- Construction cost for storm water best management practices only: $10,000 -$50,000.
- Detailed topographical survey: $2,000 - $4,000 (if not provided)
- Wetland determination, ecological screening, and environmental permitting: $2,000 - $10,000 depending on location, amount of disturbance, and type of permit needed.

The Department does not agree with this cost estimate. This section is intended to provide clarity for implementing existing requirements from both Act 13 and Chapter 102. To the extent that an operator would incur the costs listed above, they would incur those costs regardless of the status of § 78.65 because they are costs associated with complying with Act 13 and Chapter 102.

The estimated new cost associated with this section is $0.

Reporting and remediation of spills and releases (§ 78.66)

Section 78.66 establishes a reporting and remediation process for spills and releases that occur on well sites and access roads including a requirement to follow the procedures established under Act 2. Prior to this rule, the Department addressed spills through the policy "*Addressing Spills and Releases at Oil & Gas Well Sites or Access Roads*" which included allowances for use of an alternative process. The final rule eliminates use of the alternative process. The Department received significant public comment on this section from oil and gas operators indicating that the Act 2 process increases the cost of remediation by 3-4 times the alternative process. Commenters also noted an individual cost in which they asserted that the remediation should have only cost $10,000 but was expected to cost $250,000 due to the Act 2 process. Commenters did not provide any specific details to fully explain the differences in their estimated costs. Commenters also argued that the timelines established for completing various steps of a spill remediation are inappropriate and overly burdensome for the oil and gas industry.

The Department does not agree with the cost estimates. The cleanup process established under § 78.66 include the steps necessary to ensure that spills are appropriately remediated. To the extent that operators are remediating spills, they should generally be conducting the steps outlined by the Act 2 process. To the extent that operators are not conducting the steps outlined by the Act 2 process, the Department asserts that they may not be properly remediating spills. Therefore, since operators should already be conducting the required steps, the only new requirement under this rule is that operators must follow the Act 2 process in accordance with the required timelines. Since operators are required to remediate spills, the Department does not believe that the timelines established under this section represent a new cost, as commenters have noted, postponement of a cost is not an avoidance of the cost. The Department does not believe that a requirement to follow the Act 2 process represent any significant burden on the oil and gas industry.

The total cost of this provision is dependent upon the total number of spills or releases that must be reported and remediated. It is not possible for the Department to predict the number of spills or releases that will occur at well sites. Therefore, the Department is unable to provide a specific cost estimate for this provision; however, the Department does not believe that this provision represents any significant new cost to the oil and gas industry.

Borrow Pits (§ 78.67)

Subsection 78.67(b) require the registration of the location of existing borrow pits within 6o calendar days after the effective date of the rulemaking and registration of new borrow pits before there are built. This will be done electronically through the Department's website. There were a few comments from operators that this would be burdensome on industry. The Department does not believe that the requirement to register the location of existing borrow pits with the Department represents a significant burden on the industry and has not assigned a cost to this requirement.

Subsection 78.67(a) requires an oil and gas operator who owns or controls a borrow pit that does not require a permit under the Noncoal Surface Mining Conservation and Reclamation Act (NSMCRA) under the exemption in § 3273.1(b) of Act 13 to operate, maintain and reclaim the borrow pit in accordance with the performance standards in Chapter 77, Subchapter I and in accordance with Chapter 102. Commenters argued that the costs of this requirement are so high that conventional oil and gas operations would not be able to comply with them. Commenters provided the following table summarizing what they believe to be new costs imposed by this provision.

Requirement	Cost
License	$300.00
Sign	$500.00
Soil Tests	$1,500.00
Seeding	$500.00
Inspection (one-time)	$300.00
Silt fencing	$3,000.00
Sedimentation Ponds	$5,000.00
TOTAL	$11,100.00

The Department disagrees that the costs listed by the commentator represent a new cost to operators. The majority of the costs listed including soil tests, seeding, silt fence and sediment traps and basins are associated with complying with the Clean Streams Law and all oil and gas operators are currently required to comply with the Clean Streams Law. The costs that commenters attribute to sign and license are not fully explained but the Department presumes that the license cost is in reference to requirements in Chapter 77 to obtain a blasting license prior to conducting blasting. The Department does not believe that this represent a new cost to the conventional well industry. Operators who conduct blasting should already have the appropriate license to do so under Chapter 210. The Department presumes that the cost that commenters attribute to sign are based requirements in § 77.502 to display signs on the access roads to mining operations. The Department does not believe that this requirement is a performance standard under Chapter 77, Subchapter I and therefore does not represent a cost to operators under this section.

The exemption in § 3273.1(b) of Act 13 was taken verbatim from Act 223 of 1984 or the original Oil and Gas Act. This section seeks to provide clarity for implementation of those requirements; therefore, the Department has not assigned a new cost to this requirement.

The total estimated cost of these provisions is $0.

The annual cost to conventional operators is estimated between $7,504 and $28,622,568 with an initial cost of between $0 and $634,500 incurred in the first year. See the summary table in Appendix A2.

Unconventional Operators Savings

Assumptions

It is estimated that there will be approximately 2,600 unconventional wells permitted each year for the next 3 years.

Based on DEP data, approximately 1 out of every 2 permitted wells gets drilled, or approximately 1,300 wells per year.

DEP assumes there is an average of 3 unconventional wells per well site. In the future, it is estimated that less well sites will be built as there could be as many as 12 unconventional wells per well pad.

The cost analysis for this regulation must be factored on a well site basis, not on a per well basis. Many of the processes proposed for regulation in this rulemaking include activities integral to the operation of several wells and even several well pads.

2,600 wells permitted x 50% of wells drilled = **1,300 wells drilled each year**
1,300 wells drilled each year ÷ 3 wells per well site = **434 well sites built each year**

Savings Estimates

Electronic Submission of well permits (§ 78a.15(a))

The rulemaking will require applicants to submit well permit applications through the Department's website electronically. This will achieve greater efficiency and time management on the Department's end and will also save operators in postage.

2,600 permits x $5 postage savings = $13,000

The total savings of this provision is estimated to be $13,000.

Electronic Submission of water surveys as one package (§ 78a.52(d))

An operator may submit a copy of all sample results taken as part of a survey to the Department by electronic means. Currently, operators submit each individual's sample by mail as it is completely. This proposed provision will save the operator postage cost and will help the department gain efficiencies by having all samples for one well site area submitted as a whole. The Department estimates that on average, each unconventional well site will fall within the 2,500-foot range (as specified by Act 13 of 2012) of approximately 10 properties.

434 well sites x 10 properties (avg.) x $5 postage savings = $21,700

The total savings of this provision is estimated to be $21,700.

Two-year permit renewal term (§ 78a.17)

The final rule allows well permit renewals to be issued for 2 years instead of limiting the renewal term to 1 year. This represents a savings for operators that renew permits because the cost of well permit fees is reduced. The savings associated with this provision is dependent on the number of well permits that get renewed on an annual basis. Based on Department well permit data, unconventional well operators obtain well permit renewals at the following rates.

1 renewal = 6.3% of permits
2 renewals = 0.7% of permits
3 or more renewals = 0.3% of permits

Since the first renewal will be issued for a period of 2 years, the cost to renew permits for the 2nd time is eliminated by this rule. Well permits fees for unconventional wells are either $4,200 for vertical wells and $5,000 for non-vertical wells.

0.7% x 2,600 x $4,200 = $76,440
0.7% x 2,600 x $5,000 = $91,000

Therefore, the total savings of this provision is estimated to be between $76,440 and $91,000.

Well site restoration extension (§ 78a.65(c)(2))

When initially proposed, the Department estimated that well site restoration extensions would provide a savings of $21,700,000. Upon further evaluation, since the well site restoration extension provisions are established by Act 13, any savings that may be realized by this provision are based on statutory provisions and not this rule.

The total savings of this provision is estimated to be $0.

The estimated savings of this regulation on unconventional operators is approximately $125,700

Conventional Operators Savings

<u>Assumptions</u>

DEP estimates based on past trends that there will be around 2,000 conventional wells permitted each year for the next 3 years.

On average, about 2 out of every 3 permitted conventional wells are drilled.

There is typically only 1 conventional well per well site.

2,000 permitted wells x .667 drilled rate = 1,334

<u>Savings Estimates</u>

Electronic Submission of well permits (§ 78.15(a))

The rulemaking will require applicants to submit well permit applications through the Department's website electronically. This will achieve greater efficiency and time management on the Department's end and will also save operators in postage.

2,000 permits x $5 savings = $10,000

Electronic Submission of water surveys as one package

An operator may submit a copy of all sample results taken as part of a survey to the Department by electronic means. Currently, operators submit each individual's sample by mail as it is completed. This provision will save the operator postage cost and will help the department gain efficiencies by having all samples for one well site area submitted as a whole. The Department estimates that on average, each conventional well site will fall within the 1,000-foot range (as specified by the 2012 Oil and Gas Act) of approximately 4 properties.

1,334 well sites x 4 properties (avg.) x $5 postage savings = $26,680

Two-year permit renewal term (§ 78.17)

The final rule allows well permit renewals to be issued for 2 years instead of limiting the renewal term to 1 year. This represents a savings for operators that renew permits because the cost of well permit fees is reduced. The savings associated with this provision is dependent on the number of well permits that get renewed on an annual basis. Based on Department well permit data, conventional well operators obtain well permit renewals at the following rates.

1 renewal = 11.2% of permits
2 renewals = 1.6% of permits
3 or more renewals = 0.1% of permits

Since the first renewal will be issued for a period of 2 years, the cost to renew permits for the 2nd time is eliminated by this rule. Well permits fees for conventional wells are $465 on average.

1.6% x 2,000 x $465= $14,720

Therefore, the total savings of this provision is estimated to be $14,720.

The estimated savings of this regulation on conventional operators is approximately $51,400 annually.

Pipeline/Midstream Companies Savings

<u>Assumptions</u>

There are approximately 100 Horizontal Directional Drilling (HDD) operations annually.
These operations use approximately 25,000 gallons of drilling fluids to conduct HDD operations.

100 x 25,000 = 2,500,000 gallons per year for disposal

Disposal costs = $.12 per gallon

Recycling and on-site application of gathering line HDD fluid discharges and returns (§ 78.68a(k))
2,500,000 gallons x .12 = $300,000

The estimated savings of this regulation on pipeline operators and midstream companies is $300,000 annually.

<u>The total savings for the entire regulated community is estimated to be between $76,440 and $477,100.</u>

<u>Question 20</u>
(20) Provide a specific estimate of the costs and/or savings to the ***local governments*** *associated with compliance, including any legal, accounting or consulting procedures which may be required. Explain how the dollar estimates were derived.*

The Department does not anticipate that there will be significant costs or saving to local governments. One area where organizations representing municipal governments raised a cost increase issue concerned the costs associated with the requirements for using conventional well brine for road stabilization or pre-wetting roads. The final-form rulemaking requirements in § 78.70 directly track the current road spreading for dust suppression and road stabilization program, and the requirements in § 78.70a for pre-wetting, anti-icing and de-icing largely mirror those requirements. The final-form rulemaking codifies these requirements but generally does not add new substantive requirements to the existing program. To the extent that municipalities are already working with oil and gas operators as the person who owns or maintains a road where road spreading will be conducted, the municipality should have little or no new costs. To the extent that a municipality wishes to initiate such a program, the requirements to do so today are virtually identical to the requirements of the final-form rulemaking.

Additionally, the public resource impact screening provisions in Sections 78.15(f)(2) and 78a.15(f)(2) may impose a cost on local governments. In accordance with Sections 78.15(f) and 78a.15(f), conventional and unconventional operators are required to provide public resource agencies information about the location of a proposed well, including identifying the public resource, describing the public resource's function and uses and describing any mitigation measures. The public resource agency then has the option to provide written comments to the Department on a pending well permit application related to the functions and uses of the public resource and the measure, if any, needed to avoid, minimize or otherwise mitigate probable harmful impacts. To the extent that a local governmental entity manages public resources listed in Sections 78.15(f)(1) and 78a.15(f)(1), there may be a cost associated with conducting a review of information submitted and preparing written comments to the Department. As this rulemaking does not require public resource agencies to submit written comments, the final-form rulemaking does not impose a cost on public resource agencies. Any cost would be voluntary.

Question 21

(21) Provide a specific estimate of the costs and/or savings to the ***state government*** *associated with the implementation of the regulation, including any legal, accounting, or consulting procedures which may be required. Explain how the dollar estimates were derived.*

There are costs to the Department that will be incurred as a result of the implementation of the regulations. Increased field inspections and formal reviews are anticipated. More importantly however, there are provisions in the regulation package that will streamline the Department's operations that are anticipated to balance out any increased workload requirements. The following are measures included in the rulemaking with the goal of increasing Department efficiency:

- Electronic permitting will ensure that permits are submitted in a consistent format that prompts correct and complete permit applications prior to their submittal. Electronic permitting will eliminate incomplete application submittals, eliminate paper communications and increase Department complement efficiency. It will also allow for improved transparency in the Department's permitting operations.
- Upon request, require operators to directly provide the Pennsylvania Fish and Boat Commission and landowners a copy of the site specific preparedness, prevention and contingency plan, instead of having them go through a Right to Know Law request, will save the Department staff time of obtaining them on their behalf.
- Electronic notification prior to the commencement of pipeline horizontal directional drilling and liner installation so the Department's staff can schedule inspections accordingly.
- Allow for the approval for aboveground modular storage systems, which, once approved, will be posted on the Department's website for all users. This will eliminate duplication of work.
- Allow for the one-time approval for pipeline horizontal directional drilling additives, which once approved, they will be posted on Department's website as preapproved. This will eliminate duplication of work.
- Allow for the one-time approval of onsite waste processing facilities. This will eliminate duplication of work.

Additionally, the public resource impact screening provisions in §§ 78.15(f)(2) and 78a.15(f)(2) may impose a cost on state government. In accordance with §§ 78.15(f) and 78a.15(f), conventional and unconventional operators are required to provide public resource agencies information about the location of a proposed well, including identifying the public resource, describing the public resource's function and uses and describing any mitigation measures. The public resource agency then has the option to provide written comments to the Department on a pending well permit application related to the functions and uses of the public resource and the measure, if any, needed to avoid, minimize or otherwise mitigate probable harmful impacts. To the extent that a state governmental entity (for example, the Pennsylvania Department of Conservation and Natural Resources, the Pennsylvania Fish and Boat Commission, the Pennsylvania Game Commission) manages public resources listed in §§ 78.15(f)(1) and 78a.15(f)(1), there may be a cost associated with conducting a review of information submitted and preparing written comments to the Department. As this rulemaking does not require public resource agencies to submit written comments, the final-form rulemaking does not impose a cost on public resource agencies. Any cost would be voluntary.

Question 22

(22) For each of the groups and entities identified in items (19)-(21) above, submit a statement of legal, accounting or consulting procedures and additional reporting, recordkeeping or other paperwork, including copies of forms or reports, which will be required for implementation of the regulation and an explanation of measures which have been taken to minimize these requirements.

The final-form rulemaking includes new planning, reporting and record keeping requirements. However, operators have many different options for conducting surface operations; therefore, not all of the requirements will be applicable all of the time. To minimize the burden of these requirements, the Department has required electronic submission of most planning, reporting, and record keeping required in the final-form rulemaking.

The Department notes that some reporting and notification requirements that appear in the final-form rulemaking are part of the existing statutory and regulatory requirements. This the final-form rulemaking adds electronic submission requirements. Accordingly, not all of the items below are new reporting requirements (for example, permit application requirements in §§ 78.15 and 78a.15 are existing statutory and regulatory requirement).

In Sections 78.56(a)(2), 78.58(g), 78.61(d) 78a.56(a)(2), 78a.58(g), 78a.61(d), 78a.68a(f), the Department established a process for reviewing, approving and listing approved practices on the Department's website. Operators utilizing those pre-approved items will not have to obtain subsequent approvals to use the same practices at subsequent sites. For example, once an onsite processing method is approved under §§ 78.58(g) or 78a.58(g), the operator may use that processing method at other well sites with only notice to the Department rather than another request for approval. The Department developed this process to minimize the consulting and paperwork requirements associated with utilizing the practices provided for this these sections.

Many operators choose to utilize consultants for portions of their operations. New consultant work may be required to aid in the identification of public resources that may be impacted by oil and gas well sites during the permitting process. In Sections 78.15(f) and 78a.15(f) the Department sought to minimize the administrative requirements associated with preparing an application that requires the public impact screening process while still meeting its constitutional and statutory obligations to identify and protect public resources. These provisions seek to clarify when the public resource impact screening process is triggered and what information must be submitted to public resource agencies and the Department.

Similarly, the Department expects that many larger operators will continue to utilize consultants to help in the identification of abandoned and orphan wells within the defined area of review prior to drilling the well. In developing the area of review provisions, the department sought to minimize the administrative burden associated with these conducting an area of review by clarifying the report requirements.

The regulated community will need to meet new reporting requirements in the final regulation. Throughout the final-form rulemaking, most notifications, reports and submissions to the Department are to be transmitted electronically. The additional reporting requirements are as follows:

- If an operator wants to use survey results to preserve its defenses under Section 3218(d)(1)(i) or 3218(d)(2)(i), submission of pre-drill well sampling data to the Department. §§ 78.52(d), 78a.52(d) at least 10 days prior to commencement of drilling.
- If an operator chooses to dispose of drill cuttings from above the surface casing seat either by encapsulation or land application on the well site, they will be required to notify the Department 3 business days prior. §§ 78.61(f) and 78a.61(e);
- If a conventional operator chooses to dispose of contaminated drill cuttings or drill cuttings from below the surface casing seat in a pit on the well site, they will be required to notify the Department 3 business days prior and provide notice of disposal to the surface landowner with the location of the disposal site within 10 business days of the completion of the disposal. §§ 78.62(a)(5), 78.63(a)(5);
- Operators road spreading of brine from conventional wells for dust control, pre-wetting, anti-icing and de-icing activities must notify the Department 24 hours prior to the activity. §§ 78.70(k), 78.70a(q)
- An operator who wishes to make changes to a plan for road spreading of brine for dust control, road stabilization, pre-wetting, anti-icing or de-icing must submit a plan to the Department for approval. § 78.70a(s)
- An operator of a borrow pit must register the location of the borrow pit. §§ 78.67(b), 78a.67(b)
- If an operator is using a borrow pit that doesn’t fall under the permitting requirements of the Noncoal Surface Mining Conservation and Reclamation Act, they will be required to register the location of the borrow pit with the Department. §§ 78.67(b), 78a.67(b)
- Submission to the Department of an area of review report inclusive of a monitoring plan. §§ 78.52a(c), 78a.52a(c)
- If an operator wishes to use an alternate temporary storage practice, the operator must submit a request for approval to the Department. §§ 78.56(b), 78a.56(b)
- If modular aboveground storage structures are to be installed, a 3 business day notice to the Department is required. §§ 78.56(a)(4), 78a.56(a)(4)
- Operators are required to submit a list to the Department of the well sites where underground or partially buried storage tanks are located. §§ 78.57(e) & 78a.57(e)
- Operators choosing to install new underground or partially buried storage tanks must submit register the new tanks with the Department. §§ 78.57(e) & 78a.57(e)
- Notice of planned use of previously approved or new processing method 3 business days prior to initiation. §§ 78.58(d) and (g), 78a.58(d) and (g)
- The Department must be notified electronically 24 hours prior to horizontal directional drilling (HDD) activities as part of oil and gas operations. §§ 78,68a(c), 78a.68a(c)
- The Department must be notified of any water supply complaints during HDD. §§ 78.68a(j), 78a.68a(j)
- The Department must be notified of any loss or discharge of HDD fluid during HDD activities. §§ 78.68a(i), 78a.68a(i)
- Proof of consultation with Pennsylvania Natural Heritage Program regarding PNDI and Pennsylvania Historical & Museum Commission regarding historical/archaeological sites must be provided to the Department. §§ 78a.69(c)

- Proof of notification of a proposed withdrawal has been provided to municipalities and counties where water source will be located. §§ 78a.69(c)
- An operator of an existing freshwater impoundment must provide electronic notification of the impoundment's GPS Coordinates to the Township and County in which the impoundment is located. §§ 78.59b(b) & 78a.59b(b)
- If an operator uses an open pit for storage of production fluids it must report such activity to the Department. §§ 78.57(a), 78a.57(a)
- The operator must notify the department within 3 business days of the deficiencies found during the monthly inspection of tanks. §§ 78.57(i), 78a.57(i)
- The operator must demonstrate proof of compliance with §§ 102.8(l) and 102.8(m) or provide a licensed professional certification of complete site restoration to approximate original contours and return to preconstruction stormwater runoff rate, volume and quality in accordance with § 102.8(g). §§ 78.65(b) and (b)(6), 78a.65(b) and (b)(6)
- If a well site is constructed and the well is not drilled, the well site shall be restored within 9 months after the expiration of the well permit unless the department approves an extension for reasons of adverse weather or lack of essential fuel, equipment or labor. §§ 78.65(a)(3), 78a.65(a)(3)
- An application for a well permit shall be submitted electronically to the Department through its web site and contain enough information to enable the Department to evaluate the application. §§ 78.15(a). 78a.15(a)
- An operator of a planned conventional or unconventional horizontal well which will be stimulated using hydraulic fracturing must develop and submit to the Department an area of review monitoring plan. §§ 78.52a(c)(3), 78a.52a(c)(3)
- An operator that constructed a well development impoundment prior to adoption of this rulemaking shall register the location of the well development impoundment within 60 days after the effective date of adoption of this rulemaking to the Department, through the Department's website, with electronic notification of the GPS coordinates, Township and County where the well development impoundment is located. §§ 78.59b(c), 78a.59b(c)
- An operator that constructed a well development impoundment prior to adoption of this rulemaking must provide to the Department certification as to whether the impoundment meets the requirements, any impoundment that does not meet the requirements shale be upgraded to meet the requirements. §§ 78.59b(b), 78a.59b(b)
- An operator who plans to close a well development impoundment must submit electronically to the Department a well development impoundment closure plan. §§ 78.59c(a), 78a.59c(a)
- An operator seeking to manage waste on a well site in any manner other than provided in §§ 78.56 – 78.63 or §§ 78a.56 – 78a.63 must submit a request electronically to the Department describing the alternate management practice. §§ 78.63a, 78a.63a
- A water purveyor withdrawing water from waters of the Commonwealth must submit to the Department daily withdrawal volumes on a quarterly basis, in stream flow measurements and/or other water source purchases. § 78a.69(c)(3)

Many of the forms needed to implement this final-form rulemaking exist and are currently part of the regulatory program. Below is a list of forms that either need to be updated or development to implement the final-form rulemaking. The Department will make forms and guidance documents available prior to adoption of the final rule.

- Consideration of Public Resources Form. §§ 78.15(f)(3), 78a.15(f)(3)

- Landowner Questionnaire & Instructions. §§ 78.52a(b)(3), 78a.52a(b)(3)
- Survey Plat & Instructions. §§ 78.52a(c)(1), 78a.52a(c)(1).
- Oil Well Certification Form & Instructions. § 78.52a(a)
- Intent to Produce Well Naturally Form & Instructions. § 78.52a(a)
- Proof of Operator Notification Form & Instructions. §§ 78.73(c), 78a.73(c)
- Stimulation Communication Notification Form and Instructions. §§ 78.73(c), 78a.73(c)
- Form/Questionnaire to submit to landowners for location of oil and gas wells. §§ 78.52a(b)(3), 78a.52a(b)(3)
- LP certification that pit and pit liner, as built, comply with § 78.56. § 78.56(a)(16)
- Quarterly or Monthly Tank Inspection Form. §§ 78.57 (i), 78a.57(i), respectively
- Form to request to process wastewater and drill cuttings. §§ 78.58(a), (e) and 78a.58(a),(e)
- Freshwater Impoundment Registration Form. §§ 78.59b(c), 78a.59b(c)
- Land owner request to waive restoration requirement. §§ 78.59b(g), 78a.59b(g)
- Mine Influenced Water Storage in a Freshwater Impoundment Form (must include parameters that demonstrate that water stored will not cause pollution). §§ 78.59b(h)(1), 78a.59b(h)
- Form for request to use solidifiers or other alternate practices for disposal of residual waste. § 78.62(c)
- Form for request to dispose of solid fraction of residual waste by land application in alternate manner. § 78.63(c)
- Extension of Drilling or Production Period Request Forms. §§ 78.65(c)(1), 78a.65(c)(1)
- Well Site Restoration Extension Request Form. § 78.65(d)(3)
- Written Consent of Landowner Restoration. § 78.65(d)(4)
- Post Drilling Restoration Report. §§ 78.65(e), 78a.65(e)
- Post Plugging Restoration Report. §§ 78.65(f), 78a.65(f)
- Landowner Consent Forms. §§ 78.65(g), 78a.65(g)
- Material Staging Area Setback Waiver Form. § 78.68a(e)
- Water Management Plan Approval Request Form. § 78a.69(c)
- Request for modification approval of a Water Management Plan. § 78a.69(c)
- Road Spreading Plan Application. § 78.70(a)
- Road Spreading Monthly Report. § 78.70(l)
- Pre-wetting, Anti-icing and De-icing Plan Application. § 78.70a(a)
- Pre-wetting, Anti-icing and De-icing Monthly Report. § 78.71a(r)

State and local governments may incur any additional legal, accounting or consulting procedures and additional reporting, recordkeeping or other paperwork associated with the public resource screening process or road-spreading provisions.

Question 23

(23) In the table below, provide an estimate of the fiscal savings and costs associated with implementation and compliance for the regulated community, local government, and state government for the current year and five subsequent years.

	Current FY Year	FY +1 Year	FY +2 Year	FY +3 Year	FY +4 Year	FY +5 Year
SAVINGS:						
Regulated Community Unconventional Operators	$76,440 - 125,700	$76,440 - 125,700	$76,440 - 125,700	$76,440 - 125,700	$76,440 - 125,700	$76,440 - 125,700
Regulated Community Conventional Operators	$0 - 51,400	$0 - 51,400	$0 - 51,400	$0 - 51,400	$0 - 51,400	$0 - 51,400
Regulated Community Pipeline Operators	$0 - 300,000	$0 - 300,000	$0 - 300,000	$0 - 300,000	$0 - 300,000	$0 - 300,000
Local Government	$0	$0	$0	$0	$0	$0
State Government	$0	$0	$0	$0	$0	$0
Total Savings	$76,440 - 477,100	$76,440 - 477,100	$76,440 - 477,100	$76,440 - 477,100	$76,440 - 477,100	$76,440 - 477,100
COSTS:						
Regulated Community Unconventional Operators	$21,253,500 - 61,279,330	$18,895,500 - 52,816,330	$18,895,500 - 52,816,330	$5,895,500 - 31,149,664	$5,895,500 - 31,149,664	$5,895,500 - 31,149,664
Regulated Community Conventional Operators	$7,504 - 29,257,068	$7,504 - 28,622,568	$7,504 - 28,622,568	$7,504 - 28,622,568	$7,504 - 28,622,568	$7,504 - 28,622,568
Local Government	$0	$0	$0	$0	$0	$0
State Government	$0	$0	$0	$0	$0	$0
Total Costs	$21,261,004 - 90,536,398	$18,903,004 - 81,438,898	$18,903,004 - 81,438,898	$5,902,554 - 59,772,323	$5,902,554 - 59,772,323	$5,902,554 - 59,772,323
REVENUE LOSSES:						
Regulated Community	$0	$0	$0	$0	$0	$0
Local Government	$0	$0	$0	$0	$0	$0
State Government	$0	$0	$0	$0	$0	$0
Total Revenue Losses	$0	$0	$0	$0	$0	$0

(23a) Provide the past three-year expenditure history for programs affected by the regulation.

Program	**FY -3 2012-2013**	**FY -2 2013-2014**	**FY -1 2014-2015**	**Current FY 2015-2016**
Environmental	$24,965	$25,733	$28,517	$29,967

Program Management (#161-10382)				
Environmental Protection Operations (#160-10381)	$74,547	$75,184	$84,438	$90,100
Well Plugging Account (#693-60083)	$15,745	$18,686	$22,689	$30,877

Question 24

(24) For any regulation that may have an adverse impact on small businesses (as defined in Section 3 of the Regulatory Review Act, Act 76 of 2012), provide an economic impact statement that includes the following:

a) *An identification and estimate of the number of small businesses subject to the regulation.*

According to the U.S. Small Business Administration, For NAICS codes 211111 (Crude Petroleum and Natural Gas Extraction) and 213111 (Drilling Oil and Gas Wells), businesses with less than 500 employees are considered by the U.S. Small Business Administration to be small businesses. According to the Department's permitting records, there are currently approximately 75 operators of unconventional well sites in Pennsylvania, and that number is not expected to change significantly in the near term. The Marcellus Shale Coalition, an industry association that represents exploration, production, midstream, and supply chain partners of unconventional natural gas drilling, has estimated that less than half of the operators affected may be classified as a small business.

The Department estimates that almost all of the 5,808 conventional operators that operate within Pennsylvania are small businesses. For purposes of this analysis, the Department will presume that all operators that operate only conventional wells are small businesses. Some operators have both conventional and unconventional wells and are counted in each category above.

Because the small business determination for pipeline companies is based on gross annual receipts of less than $33.5 million for oil and gas pipeline and related structures construction companies and less than $25.5 million for pipeline transportation of natural gas companies, the Department is unable to determine the number of pipeline companies operating in Pennsylvania that would qualify as small businesses.

The estimated total is 5,844 small businesses that would be subject to this regulation.

b) *The projected reporting, recordkeeping and other administrative costs required for compliance with the regulation, including the type of professional skills necessary for preparation of the report or record.*

The following are provisions of the regulation that may or may not apply to an operator based on their chosen business practices and operations.

Reporting

1) Submission to the Department of proof of written notification by an unconventional well operator to a homeowner explaining that some of their rights may be waived if they refuse to allow the operator to conduct a predrill survey on their water supply. 78.52(f), 78a.52(f);

   No special skills are required.

2) If an operator wants to use survey results to preserve its defenses under Section 3218(d)(1)(i) or 3218(d)(2)(i), submission of pre-drill well sampling data to the Department. 78.52(d), 78a.52(d);

   No special skills are required.

3) If an operator chooses to use an on-site pit for disposal on the well site, they will be required to submit documentation of the seasonal high groundwater table elevation and the name and qualifications of the individual who performed the evaluation. The operator will also be required to notify the department 3 days prior to installation of the pit liner. 78.56(e) and 78.62(a)(9);

   Special skills required include the ability to identify the seasonal high groundwater table elevation. Typically, a soil scientist, hydrogeologist, or other experienced person such as a Sewage Enforcement Officer (SEO) can make the determination. The Department will provide free training to operators so that they will be able to make this determination themselves.

4) If an operator chooses to use a well development impoundment, they will be required to submit documentation of the seasonal high groundwater table elevation and the name and qualifications of the individual who performed the evaluation. The operator will also be required to notify the department 3 days prior to installation of the pit liner. §§ 78.59b(f), and 78a.59b(f);

   Special skills required include the ability to identify the seasonal high groundwater table elevation. Typically, a soil scientist, hydro geologist, or other experienced person such as a Sewage Enforcement Officer (SEO) can make the determination. The Department will provide free training to operators so that they will be able to make this determination themselves. For larger impoundments, a greater level of expertise may be required.

5) If an operator chooses to dispose of drill cuttings from above the surface casing seat either by encapsulation or land application on the well site, they will be required to notify the Department 3 business days prior. §§ 78.61(f) and 78a.61(e);

   No special skills are required to provide the Department with 3 business day notice.

6) If a conventional operator chooses to dispose of contaminated drill cuttings or drill cuttings from below the surface casing seat in a pit on the well site, they will be required to notify the Department 3 business days prior and provide notice of disposal to the surface landowner with the location of the disposal site within 10 business days of the completion of the disposal. §§ 78.62(a)(5), 78.63(a)(5);

No special skills are required to provide a 3 business day notice to the Department and provide the landowner with the location of the disposal site within 10 business days of the disposal completion.

7) If an operator chooses to spread brine from conventional wells for dust control, pre-wetting, anti-icing and de-icing activities must notify the Department 24 hours prior to the activity. §§ 78.70(k), 78.70a(q);

   No special skills are required to provide the Department with 24-hour notice prior to the proposed activity.

8) An operator who wishes to make changes to a plan for road spreading of brine for dust control, road stabilization, pre-wetting, anti-icing or de-icing must submit a plan to the Department for approval. § 78.70a(s);

   No special skills are required to provide the Department with a modified plan of the proposed activity.

9) An operator of a borrow pit must register the location of the borrow pit. §§ 78.67(b) and 78a.67(b);

   A basic understanding of the use of GPS, GIS software or other means of determining latitude/longitude is required.

10) If an operator is using a borrow pit that doesn't fall under the permitting requirements of the Noncoal Surface Mining Conservation and Reclamation Act, they will be required to register the location of the borrow pit with the Department. §§ 78.67(b), 78a.67(b);

    A basic understanding of the use of GPS, GIS software or other means of determining latitude/longitude is required.

11) Submission to the Department of an area of review report inclusive of a monitoring plan. §§ 78.52a(c) and 78a.52a(c);

    Special skills that may be required include knowledge and experience in planning, conducting and monitoring hydraulic fracturing activities in a manner considerate of addressing potential communication risks with offset wells. Typically, the person providing an area of review study/report would have more than minimal experience in the oil and gas industry, such as an experienced oil and gas professional, or a professional geologist or engineer. However, the person that submits the report is not required to have no special skills.

12) If an operator wishes to use an alternate temporary storage practice, the operator must submit a request for approval to the Department electronically through its website. §§ 78.56(b), 78a.56(b);

    The only new requirement in this section is that the request must be submitted electronically. No special skills are required to provide documents electronically to the Department.

13) If modular aboveground storage structures are to be installed, a 3 business day notice to the Department is required. §§ 78.56(a)(4), 78a,56(a)(4);

No special skills are required to provide the Department with a 3 business day notice prior to the planned activity.

14) Operators are required to submit a list to the Department of the well sites where underground or partially buried storage tanks are located. Operators choosing to install new underground or partially buried storage tanks must submit register the new tanks with the Department. 78.57(e) & 78a.57(e);

No special skills are required to compile and submit a list of well sites where underground or partially buried storage tanks are located.

15) If an operator chooses to conduct waste processing onsite they must provide notice of planned use of previously approved or new processing method at least 3 business days prior to initiation. §§ 78.58(d), (g), 78a.58(d),(g);

No special skills are required to provide to the Department a 3 business day notification prior to the planned activity.

16) If an operator chooses to conduct horizontal directional drilling (HDD) for unconventional gas pipelines, the Department must be notified electronically 24 hours prior to all HDD activities. § 78a.68a(c);

No special skills are required to provide the Department electronic notification 24 hours prior to the planned HDD activities.

17) The Department must be notified of any water supply complaints during HDD. § 78a.68a(j);

No special skills required to notify the Department of any water supply complaints during HDD activities.

18) The Department must be notified of any loss or discharge of HDD fluid during HDD activities. § 78a.68a(i);

No special skills are required to notify the Department of any loss or discharge of HDD fluid during HDD activities.

19) Proof of consultation with Pennsylvania Natural Heritage Program regarding PNDI and Pennsylvania Historical & Museum Commission regarding historical/archaeological sites must be provided to the Department. § 78a.69(c);

No special skills are required to provide the Department with "Proof of Consultation" from the Pennsylvania Natural Heritage Program regarding PNDI and the Pennsylvania Historical & Museum Commission regarding historical/archaeological sites.

20) Proof of Notification of a proposed withdrawal has been provided to municipalities and counties where water source will be located. § 78a.69(c);

No special skills are required to provide to the Department with "Proof of Notification" to municipalities and counties where a water source will be located.

21) An operator of an existing well development impoundment must provide electronic notification of the impoundment's GPS Coordinates to the Township and County in which the impoundment is located. §§ 78.59b(b) & 78a.59b(b);

A basic understanding of the use of GPS, GIS software or other means of determining latitude/longitude is required.

22) If an operator uses an open pit for storage of production fluids it must report such activity to the Department. §§ 78.57(a), 78a.57(a);

No special skills are required to report to the Department the use of open pits for the storage of production fluid.

23) The operator must notify the department within 3 business days of the deficiencies found during periodic tank inspections. §§ 78.57(i) & 78a.57(i);

No special skills are required to notify the Department within 3 business days of any deficiencies found during periodic tank inspections.

24) Surface Restoration Plan. §§ 78.65(b) & 78a.65(b);

Compiling a written site restoration plan may require a licensed professional knowledgeable of surface restoration requirements including rules, regulations and techniques. Larger and more challenging sites such as sites on steep slopes or weak soils may require more specialized skills. Generally, the Department does not expect that site restoration will be any more challenging than site construction from a technical perspective.

25) The operator must demonstrate proof of compliance with §§ 102.8(l) and 102.8(m) or provide a licensed professional certification of complete site restoration to approximate original contours and return to preconstruction stormwater runoff rate, volume and quality in accordance with § 102.8(g). §§ 78.65(b), 78a.65(b), 78.65(b)(6), 78a.65(b)(6);

Special skills required include a licensed professional capable of providing certification of site restoration to approximate original contours and returned to preconstruction stormwater runoff rate, volume and quality. The person would be knowledgeable with the requirements of Chapter 102 related to site stabilization and Post Construction Stormwater Management. Typically, such knowledge is possessed by a professional geologist, professional engineer, or other certified licensed professional, such as a professional land surveyor or a licensed landscape architect.

26) An application for a well permit shall be submitted electronically to the Department through its web site and contain enough information to enable the Department to evaluate the application. §§ 78.15(a). 78a.15(a);

The only new requirement in this section is that the application must be submitted electronically. No special skills are required to provide documents electronically to the Department.

27) An operator of a planned conventional or unconventional horizontal well which will be stimulated using hydraulic fracturing must develop and submit to the Department an Area of Review monitoring plan. §§ 78.52a(c)(3), 78a.52a(c)(3);

Special skills required include knowledge and experience in planning, conducting and monitoring hydraulic fracturing activities in a manner considerate of addressing potential communication risks with offset wells. Typically, the person providing an area of review study/report would have more than minimal experience in the oil and gas industry, such as an experienced oil and gas professional, or a professional geologist or engineer. However, the person that submits the report is not required to have no special skills.

28) An operator that constructed a well development impoundment prior to adoption of this rulemaking shall register the location of the well development impoundment within 60 days after the effective date of adoption of this rulemaking to the Department, through the Department's website, with electronic notification of the GPS coordinates, Township and County where the well development impoundment is located. §§ 78.59b(c) & 78a.59b(c);

A basic understanding of the use of GPS, GIS software or other means of determining latitude/longitude is required.

29) An operator that constructed a well development impoundment prior to adoption of this rulemaking must provide to the Department certification as to whether the impoundment meets the requirements, any impoundment that does not meet the requirements shale be upgraded to meet the requirements. §§ 78.59b(b) & 78a.59b(b);

The requirements well development impoundments must meet include having a synthetic liner, being surrounded by a fence and ensuring that MIW or other water sources stored appropriately. No special skills are required to identify a synthetic liner in an impoundment or a fence surrounding an impoundment. Special skills required include a licensed professional capable of determining whether an impoundment meets current requirements and provide to the Department certification of the finding.

30) An operator who plans to close a centralized impoundment must submit electronically to the Department a well development impoundment closure plan. §§ 78.59c(a) & 78a.59c(a);

Special skills required include a licensed professional with knowledge of developing an impoundment closure plan. Services of a licensed professional engineer and geologist may be required. Closure of a centralized impoundment should not generally be more complex than construction of the impoundment.

31) An operator seeking to manage waste on a well site in any manner other than provided in §§ 78.56 – 78.63 or 78a.56 – 78a.63 must submit a request electronically to the Department describing the alternate management practice. §§ 78.63a, 78a.63a;

    Special skills required include a person with considerable experience in the oil and gas industry and knowledgeable of alternate waste management practices. Typically, an experienced oil and gas professional possesses the necessary knowledge to manage waste on a well site.

32) A water purveyor withdrawing water from waters of the Commonwealth must submit to the Department daily withdrawal volumes on a quarterly basis, in stream flow measurements and/or other water source purchases. § 78a.69(c)(3);

    No special skills are required to provide the Department daily water withdrawal volumes, instream flows and other water source purchases on a quarterly basis. Design and construction of facilities necessary to monitor withdrawals and in-stream flow measurements may require engineering expertise.

33) Entities (operators, municipalities, private contractors, PennDOT, etc.) that choose to land apply brine for dust suppression, road stabilization, anti-icing, or deicing will be required to submit monthly brine spreading reports to the Department. § 78.70a(r)

    No special skills are required to provide to the Department monthly brine spreading reports.

34) An operator is required to keep records of the locations of temporary pipelines, the types of fluids transported through those pipelines, and the period of time in which the pipeline was installed. § 78a.68b(m)

    No special skills are required to administratively maintain the location of temporary pipelines, when they were installed and the type of fluids transported.

c) A statement of probable effect on impacted small businesses.

Some additional costs to unconventional and conventional operators classified as small businesses will occur as a result of these regulations; however, the Department has minimized the costs of this rulemaking to small businesses (primarily conventional well operators), as described in number 25 below.

The new costs as described in this document are new costs in the sense that they are new regulatory requirements but many of the new costs associated with this rule are from what the Department believes to be common sense practices and controls that operators are already implementing. Some examples include periodic tank inspection and maintenance which can prevent costly spills and releases and the area of review survey which can prevent communication with other wells which may result in both environmental damage and significant financial losses for the operator. All of these issues are explained in detail in the answers to questions 10 and 19. Also, the Department anticipates there will be areas of cost savings that will occur as a result of the rulemaking as well. Overall, the Department does not believe that the rule will result in any significant adverse impact on oil and gas operators including those which meet the definition of a small business.

In addition, as concluded by a 2011 Penn State study, many small businesses in Pennsylvania benefit from the $1.145 billion dollars in annual economic activity and 12,630 jobs provided by tourism to Pennsylvania's State Parks. This regulation will ensure that those businesses will continue to benefit as these facilities will be protected through additional avoidance and mitigation measures taken by well operators.

http://dcnr.state.pa.us/stateparks/thingstoknow/economicimpact/index.htm

d) *A description of any less intrusive or less costly alternative methods of achieving the purpose of the proposed regulation.*

The Department designed this regulation around performance based standards, allowing each individual operator to choose which practices are best for their operations. There are many options for management of waste streams, but those practices which have a higher likelihood of impacting the environment and public safety and health will be required to have additional controls to ensure the highest level of protection to the Commonwealth.

Conventional well operations are much smaller in scope and generate far less waste than unconventional drilling; therefore, the potential impact to the environment is less. This has been taken into consideration while the regulations were being developed, which resulted in the exclusion of conventional operations from several sections of this regulation. A list of the regulatory requirements applicable to conventional operations is provided in response to Question 15 above.

A number of less costly and less burdensome alternatives were considered during the development of the final rulemaking for small businesses, which, in this case, are considered to be conventional operators. Please see the response to Question 25 for a list of the alternatives that were considered, but removed from, or never added to Chapter 78 for the conventional industry.

Question 25

(25) List any special provisions which have been developed to meet the particular needs of affected groups or persons including, but not limited to, minorities, the elderly, small businesses, and farmers.

The Department took into consideration some special provisions for land owners, specifically farmers, with regard to potential emergencies and land uses. If a property owner would like to receive a copy of the Preparedness, Prevention, and Contingency Plan, the operator must provide it to them. If a landowner prefers to retain a well development impoundment or well pad on their property, the operator may obtain signed landowner consent and will not be required to restore the area. Mostly developed for the need of farmers, a well site must be restored to the approximate original conditions, including the preconstruction contours and be able to support the original land uses within nine months after plugging a well. Operators will also be required to provide a copy of the site restoration report to the landowner if drill cuttings or residual waste are disposed on the well site. This will ensure that the landowner does not lose property or future crop growing areas through oil and gas activities.

As described in response to Question 15 above, the Department also considered and minimized the regulatory burden on conventional well drillers to include only those provisions deemed necessary to protect public health and the environment. The Department presumed that all conventional well drillers that are not also unconventional well drillers to be small business, and believes that all of the requirements in Chapter 78 are appropriate for small businesses. Chapter 78 is less stringent than Chapter 78a in the following key ways. For more information about the provisions below, please see response to Question 10.

Under 78.15(f) -water well, surface water intake, reservoir or other water supply extraction points used by a water purveyor are not included in the list of public resources that must be considered when obtaining a well permit while unconventional must consider these public resources in the well permit application process in accordance with Section 3215(c)(6).

Under § 78.55 emergency response plans are not required as by statute they are only required for unconventional well sites. Only a Preparedness, Prevention and Contingency (PPC) Plan is required.

Under § 78.56 pits are allowed for temporary storage of wastes on well sites. Pits may not be used at unconventional well sites under § 78a.56.

Under § 78.56 fencing is not required around pits. A requirement to install fencing around pits at conventional well sites was initially proposed but was removed from this section in the final-form rulemaking.

Under § 78.56 Measures to prevent unauthorized access by third parties is not required for tank valves and access lids. A requirement to install measures such as locking tank lids and valves to prevent unauthorized access by third parties at conventional well sites was initially proposed but was removed from this section in the final-form rulemaking.

Under § 78.56 signs on or near the tank or other approved storage structure identifying the contents and an appropriate warning of the contents is not required.

Under § 78.56 pits with an aerial extent of 3,000 ft^2 and a total volume of 125,000 gallons may be constructed and utilized at conventional well sites under a permit-by-rule. Operators that propose to utilize pits larger than this must obtain approval from the Department prior to construction. Initially the rule included a requirement that the interior slopes of pits had to be 2 horizontal to 1 vertical or flatter.

Under § 78.57 operators may still use underground or partially buried storage tanks to store brine or other fluids produced during operation of the well. When proposed, the rule required operators to remove all underground or partially buried storage tanks and banned continued use of such tanks.

Under § 78.57 measures to prevent unauthorized access by third parties is not required for tanks storing brine or other fluids produced during operation of the well.

Under § 78.57 tanks storing brine or other fluids produced during operation of the well must be inspected by the operator at least once per calendar quarter. Storage tanks used at unconventional well sites must be inspected at least once per month.

Under § 78.61 drill cuttings from below the casing seat may be disposed either in a pit that meets the § 78.62 requirements or by land application in accordance with § 78.63.

Under 78.62 residual waste generated by the drilling or stimulation of an oil or gas well can be disposed in pits. Drill cuttings produced by the drilling of unconventional wells may only be disposed in a pit on the site if an individual disposal permit is first obtained from the Department.

Under 78.63 residual waste generated by the drilling or stimulation of an oil or gas well can be disposed by land application. Drill cuttings produced by the drilling of unconventional wells may only be disposed by land application on the site if an individual disposal permit is first obtained from the Department.

Under 78.65 drilling supplies and equipment (not needed for production) stored at conventional well sites with the written consent of the surface landowner do not need secondary containment. Supplies and equipment not needed for production stored on unconventional well sites must be stored within secondary containment as appropriate.

Under 78.65 a written site restoration plan is not required. Operators may develop a written site restoration plan to comply with requirements in Chapter 102, as appropriate.

Requirements relating to oil and gas gathering lines, horizontal directional drilling for oil and gas pipelines requirements and well development pipelines for oil and gas operations requirements are not included in Chapter 78. These requirements remain in Chapter 78a.

The requirements to develop a water management plan are not included in Chapter 78.

Road spreading of brine from conventional oil and gas wells for dust control and road stabilization and the use of bring for pre-wetting, anti-icing and de-icing is allowed. Brines from unconventional gas wells may not be spread on roadways for any reason.

Under Section 78.122(b), conventional operators are required to report waste annually. Unconventional operators must report waste on a monthly basis.

Question 26

(26) *Include a description of any alternative regulatory provisions which have been considered and rejected and a statement that the least burdensome acceptable alternative has been selected.*

Alternative regulatory provisions that were considered by the Department include the elimination of pits and underground storage tanks for the management of wastes. The Department also considered requiring landowner consent prior to the disposal of cuttings or residual waste at the well site. Given the longstanding and successful use of these practices by conventional well operators, the Department determined that such restrictions were not practical.

The Department also considered requiring operators to identify oil and gas wells in the area of review prior to well permitting and site construction. Because over 40% of all wells permitted are never drilled, the Department determined that identification prior to drilling represented a more efficient and results-oriented process. This timing also still affords the operator a chance to change the location of the well to mitigate hydraulic fracturing communication risks. The Department also considered larger survey areas in association with the area of review – distances as far as a mile away from the well undergoing stimulation had been proposed. However, final survey areas were ultimately based on an analysis of existing data and observed industry practices related to well spacing. Finally, with regard to the area of review regulation, the Department considered a requirement to plug wells prior to hydraulic fracturing. However, it was ultimately determined that risk mitigation can be effectively implemented in more than one way and allowing operational flexibility is a superior way to implement such a regulatory requirement.

The Department considered requiring permits prior to the use of various facilities such as well development impoundments, modular storage structures and onsite processing. However, this regulation is designed around planning, pre-approvals, notifications of certain activities, and specific construction and operation standards including monitoring, inspection, and reporting requirements. This eliminates a traditional permitting process. For pre-approvals of solidifiers, modular storage, and wastewater processing operations, the Department will post online each of the previously approved chemicals, methods, and systems to further enhance business efficiencies.

Additionally, if a permit applicant obtains an erosion and sediment control permit under Pa Code Chapter 102, proof of consultation with the Pennsylvania Natural Heritage Program as part of the well permit application will be deemed as being met.

The Department considered more than 5,000 unique comments received during both comment/response periods. All comments are included in the comment/response document along with the Department's responses. Every comment suggesting a change in the regulation is a regulatory alternative considered by the Department. The Department considered alternative regulatory provisions whenever it was possible to do so and at the same time not allow the requirements of the rulemaking to be any less protective of the health and safety and natural resources of this Commonwealth. Although specific examples are referenced below, additional information can be found throughout the comment/response document. In addition, see the answer to question 10 for a detailed discussion of major revisions to the final rule. The Department believes that all revisions made in the final rule result in the least burdensome, acceptable alternative.

Definition of Oil and Gas Operations

Initially, "well location assessment" and "seismic operations" were included in the definition of oil and gas operations. The Department received many comments requesting clarification of the term Oil and Gas Operations. The Department has amended the definition of Oil and Gas Operations by removing those two terms. The definition, as revised, is the least burdensome, acceptable alternative.

Setbacks and consideration of public resources

Several commenters suggested the language in the rulemaking should require setbacks of 1,000 feet or greater from wells to public resources. The Department considered these comments but declined to make these suggested changes to this final-form rulemaking Importantly, the distances included in §§ 78.15(f) (1) and 78a.15(f)(1), are not setbacks. The distances in these provisions define an area that requires coordination with public resource agencies and additional consideration during the permit review process to determine if drilling is appropriate or will cause conflicts. However, these provisions do not explicitly prohibit drilling activities within these defined areas, as a "setback" would suggest. In Section 3215(a) of the 2012 Oil and Gas Act, the General Assembly established setbacks prohibiting the drilling of oil and gas wells within certain distances from buildings and drinking water wells. For a conventional well, this distance is 200 feet; for an unconventional well, this distance is 500 feet. Additionally, unconventional wells may not be drilled within 1000 feet of a public water supply. Suggestions to change the setbacks should be a legislative change to the 2012 Oil and Gas Act.

Commenters also argued that the trigger distance for a public resource impact screen was inappropriate. The Department considered both shorter and longer distances. The distances to certain public resources identified in §§ 78.15(f)(1) and 78a.15(f)(1) of the final rulemaking are consistent with those used by the Department to consider public resources in well application forms since the oil and gas permitting program was established under the 1984 Oil and Gas Act. The Department has found these distances to be effective for purposes of identifying and considering potential impacts to public resources. However, given the increased size of well sites constructed when enhanced development techniques such as hydraulic fracturing are used, Sections 78.15(f)(1) and 78a.15(f)(2) require these distances to be measured from the limit of disturbance of the well site rather than from the well itself, as was the prior practice. For conventional operations this change will have little to no practical effect given the relatively small size of these conventional sites.

Commenters suggested extending the public resource impact screening process to additional public resources and additional oil and gas-related activities (i.e. pipeline, compressor stations, and ancillary support facilities). The Department considered these options and determined that the process outlined in these provisions provide the least burdensome acceptable approach. Many of the suggested additional public resources are addressed in other provisions in Chapter 78 and 78a or other regulations, permits and policies implemented by the Department under Pennsylvania's environmental laws. Notwithstanding the enumeration of specific public resources in the regulations, the Department will consider the potential impacts to other public resources identified during the permitting process.

When initially proposed, the rule did not include a requirement for public resource impact screens for well sites proposed within 200 feet of common areas of a school's property or playground and wellhead protection areas. Based on comments received, common areas of a school's property or playground and well head protection areas were added because these resources are similar in nature to the other listed public resources. Playgrounds and school common areas are frequently used by the public for recreation, similar to parks. Wellhead protection areas are associated with sources used for public drinking supplies, another listed resource. In further response to comments, wellhead protection areas have been clarified by including a cross reference to 25 Pa. Code §109.713 and limiting the areas to those classified as zones 1 and 2.

Noise Mitigation Requirements

The Department considered including noise mitigation requirements in the final rule. Based on public comment to the proposed rulemaking raising concerns over noise issues at unconventional well sites, the Department developed section 78a.41 (relating to noise mitigation) to address noise issues at unconventional well sites and published that provision as part of the ANFR on April 4, 2015.

Since that time, the Department has determined that the consideration of noise and possible mitigation is a concern not only with regard to unconventional gas production, but is an issue raised by other activities regulated by the Department (for example, mining). Because of this, additional cross-program collaboration and coordination will be required. In addition, there are a number of extremely complex technical issues that have to be resolved in order to develop a reasonable but effective noise mitigation program. This complexity is demonstrated in the scope and breadth of the comments submitted on the ANFR, both supporting and opposing these draft regulatory provisions. Finally, the science surrounding noise issues is continuing to develop, particularly with regard to impacts to human health and sensitive wildlife populations. Any reasonable and effective regulation relating to noise issues will need to take those developments into account.

For these reasons, the Department has removed section 78a.41 from the final rulemaking in order to consider standards and enforcement that will maximize consistency and efficiency, where possible, among Department programs, while addressing the complex technical issues presented by noise at well sites. In its place, the Office of Oil and Gas Management intends to develop a noise mitigation "best practices manual" with input from a wide range of experts on noise issues as well as the public. If the rulemaking is appropriate to address noise issues at well sites, the Department will develop such regulations at a later date. Exclusion of noise mitigation requirements is the least burdensome, acceptable alternative at this time.

Protection of Water Supplies

Many commenters argued that use of the term "exceeded" in § 3218(a) of Act 13 should be interpreted to describe a water supply that did not meet Pennsylvania Safe Drinking Water Act (SDWA) standards instead of using the term "exceeded" to describe a water supply that had water quality better than SDWA. The impact of this interpretation would be that water supplies where water quality was documented prior to being affected by oil and gas activities as being higher quality than required by the SDWA would only require restoration to SDWA standards. Additionally, water supplies that did not meet SDWA standards prior to being impacted by oil and gas operations would only require restoration to the previous poor quality. The final rulemaking requires water supplies to be restored to SDWA standards or better. The SDWA standards are based on scientific fact as far as what is, and is not in a water supply to determine if it is safe for human consumption. When the water quality has been documented before being affected by oil and gas operations, that documented water quality, even if it is of a higher quality than SDWA standards, must be re-established by the operator. Otherwise, the Department will be allowing operators to degrade a natural resource relied upon as a water supply source. In regard to water supplies that did not meet SDWA standards prior to being impacted by oil and gas operations, the Department would be derelict in its duties if it allowed operators to provide replacement drinking water that by its own standards is not fit to drink simply because the pre-existing water supply was poor.

The final rule requires restoration of impacted water supplies such that the restored supply "is comparable to the quality of water that existed prior to pollution if the water quality was better than these standards." This provision of the final rule represents the least burdensome, acceptable alternative because it is what is required by Act 13.

Predrilling or pre-alteration survey

The Department initially proposed submittal of the predrilling or pre-alteration survey results to the Department within 10 business days of the completion of the survey. The Department received many comments expressing concerns on proposed requirements. Commenters argued that this strict bright-line rule is both arbitrary and unnecessarily punitive. Also, the assignment of an API number is beyond operator control and is independent of pre-drill sampling. As a result, the Department has changed the rulemaking language to allow all sample results pertaining to the well of concern to be submitted to the Department electronically by the operator 10 days prior to commencement of drilling of the well. This was selected to give the operator control of when sample results must be submitted to the Department and allows operators to collect samples closer to the actual time of drilling. This provision is less burdensome and an acceptable alternative that ensures pre-drilling or pre-alteration surveys are submitted to the Department in a timely manner.

The Department received significant public comment that the rule should include a specific list of potential contaminants that must be analyzed for in each pre-drilling or pre-alteration survey. The Department believes that the General Assembly chose to place the responsibility of not conducting a predrill survey on the backs of operators, who might not be able to rebut a presumption of liability if a water supply is not sampled prior to drilling or a particular substance is not tested for by the operator. By failing to establish predrill water quality, the operator opens itself up to liability for any failure to meet drinking water standards in any water supply located within the presumption's radius for any substance found in the water supply. Therefore, presumption is more protective of water supplies than a prescribed list of contaminates to be sampled for with a pre-drill or pre-alteration water sample. This provision is the least burdensome, acceptable alternative.

Pits for Temporary Storage

Many commenters urged the Department to ban the use of all pits and open top structures. The final rule bans the use of pits for temporary waste storage at unconventional well sites under § 78a.56. The Department has determined that it is appropriate to remove this practice because it is not commonly used by unconventional operators. Additionally, the typical type and scope of use by unconventional operators is generally incompatible with technical standards for temporary pits prescribed under § 78.56. Conversely, the typical type and scope of use by conventional operators is generally compatible with the technical standards for temporary pits prescribed under § 78.56. The Department has allowed the disposal of residual wastes including contaminated drill cuttings in a pit at conventional well sites for decades. When done in accordance with appropriate environmental standards, such disposal can occur without significant harm to public health and safety or the environment. Therefore, the Department has updated the standards for pits in §§ 78.56 and 78.62 and the final-form rulemaking retains pits as an option for proper temporary waste storage at conventional well sites. Disallowing the use of pits at unconventional well sites but continuing to allow pits for temporary storage at conventional well sites is the least burdensome, acceptable alternative.

Notification Requirements for Temporary Storage

Sections 78.56 and 78a.56 require notification to the Department 3 days prior to the date an operator plans to construct modular aboveground storage facilities. In addition, § 78.56 requires notification to the Department 3 days prior to pit construction. Many commenters argued that 3 days is insufficient notice to the Department, while many other commenters argued that 3 days is overly burdensome on operators. Based on the comments received from operators regarding the need for re-notification if the date of construction is extended, the Department modified the respective sections. The final regulatory language requires 3-day notification, but in case of re-notification 3-day advance notice is not required. The Department believes that the notification timeframe established in the regulations is necessary to allow Department field staff to plan inspection schedules and ensure efficient use of time.

Unauthorized Access by Third Parties

When originally proposed, §§ 78.56(a) and 78a.56(a) addressed security requirements for pits, tanks and approved storage structures and required operators to equip all tank valves and access lids to regulated substances with reasonable measures such as locks, open end plugs, removable handles, retractable ladders or other measures to prevent unauthorized access by third parties. The Department received significant public comment from conventional operators indicating that the costs associated with equipping pits, tanks and approved storage structures with the prescribed security measures would be exorbitant for the conventional industry which reportedly uses approximately 175,000 tanks. The Department agreed that changes to§ 78.56 to remove the requirement to install equipment to prevent unauthorized access by third parties are appropriate for conventional operations but has retained this requirement for unconventional operators in § 78a.56. This provision is the least burdensome, acceptable alternative.

Pit Slope Requirements

When originally drafted, the Department included a requirement that temporary pits must have an inside slope 2:1 (horizontal: vertical) or flatter. The Department received significant public comment on this proposed requirement and ultimately removed the minimum slope requirement from the final rulemaking. Instead, the final rule continues to allow conventional operators to construct pits with steep inside slopes provided that the pits have an aerial extent of less than 3,000 ft^2 and volumetric capacity of less than 125,000 gallons. For larger pits, the rule requires the operator to obtain a site specific approval from the Department prior to constructing the pit. This requirement is necessary because the definition of conventional formation is very broad and technological advances may result in conventional operators utilizing large pits that are in place for a long period of time, similar to the type and scope of pit use by unconventional operators. The Department has determined that this type of pit use is generally incompatible with the technical standards for temporary pits prescribed under § 78.56. This revision will allow continued use of pits at conventional well sites, prevent an unnecessary increase in the footprint of pits and provide appropriate protections to the environment when operators require the use of large pits. The Department believes that the revised requirements are consistent with the Pennsylvania Constitution and applicable statutes and reasonably and adequately balance protection of the public health and natural resources against the fiscal impact on the conventional oil and gas industry. This provision is the least burdensome, acceptable alternative.

Ban the use of and force removal of all buried tanks.

When originally proposed, Chapter 78 banned further use of underground storage tanks and required both conventional and unconventional operators to remove all underground storage tanks within 3 years of the effective date of the final rule. Several comments were received urging the Department to ban the use of and require removal of all existing buried tanks. The Department acknowledged the economic impacts of the proposed provision requiring removal of underground storage tanks at well sites suggested in the proposed language in December 2013 and so has amended the final rulemaking accordingly. Continued use of underground storage tanks at oil and gas well sites will be allowed under the final rulemaking. However, there are tens of thousands of these underground storage tanks at well sites across the Commonwealth, and proper standards for operation and maintenance of these storage tanks are critical for protection of the environment from spills and releases. For example, Section 3218.4(b) of the 2012 Oil and Gas Act establishes that permanent aboveground and underground tanks must comply with the applicable corrosion control requirements in the Department's storage tank regulations. Provisions in §§78.57(e) and 78a.57(e) require underground or partially buried storage tanks used to store brine or other fluids produced during operation of the well shall be designed, constructed and maintained to be structurally sound in accordance with sound engineering practices adhering to nationally recognized industry standards and the manufacturer’s specifications. The provision allowing continued use of underground or partially buried tanks with appropriate controls is the least burdensome, acceptable alternative.

Periodic inspection of production tanks

The final rule requires operators to inspect production tanks at conventional well sites once per calendar quarter and production tanks at unconventional well sites once per calendar month. When initially proposed the rule did not require periodic inspections of production tanks, however, as a result of public comment, the Department determined that periodic inspection of these tanks was reasonable and appropriate. When the Department issued the Advance Notice of Final Rulemaking, the draft required all operators to inspect production tanks on a monthly basis. Comments were received in opposition to the requirement that tanks at conventional well sites must be inspected monthly. As a result, the Department has amended subsection 78.57(h) to reduce the frequency of inspection from once per calendar month to once per calendar quarter to allow coordination between tank inspections and mechanical integrity assessments required under § 78.88 which requires wells to be inspected on a quarterly basis for the conventional industry. Unconventional operators must report monthly. This reduction in frequency will also reduce tank inspection costs by 67% due to the reduction in the number of inspections that must occur and matching the frequency with the MIA inspection will prevent any additional travel costs associated with complying with the inspection requirement. The requirement to inspect production tanks at conventional well sites once per calendar quarter and production tanks at unconventional well sites once per calendar month is the least burdensome, acceptable alternative.

Centralized Tank Storage

Based on public comment to the proposed rulemaking raising concerns over the lack of permitting options for centralized off-site tank storage, the Department developed §§ 78.57 and 78a.57 (relating to centralized tank storage) to provide for the option of centralized tank storage off of the well site under the oil and gas regulations. These sections were developed with significant input and review from the Department's waste management and storage tank programs to ensure that the draft final-form rulemaking requirements were protective of public health and safety and the environment. The Department also felt that these sections were appropriate for inclusion in the draft final-form rulemaking to give operators an environmentally-protective option for off-site wastewater management given the Department's decision to eliminate the use of centralized impoundments without residual waste permits in §§ 78.59c and 78a.59c of the draft final-form rulemaking. These sections were published as part of the Advance Notice of Final Rulemaking on April 4, 2015.

There was widespread opposition to these new sections across the spectrum of commenters, for various reasons. In keeping with the Department's interpretation of section 3273.1(a) of the 2012 Oil and Gas Act (58 P.S. § 3273.1(a)), and the decision to eliminate the use of centralized impoundments without residual waste permits in §§ 78.59c and 78a.59c of the draft final-form rulemaking, the Department removed §§ 78.57 and 78a.57 from the final-form rulemaking. Operators wishing to manage oil and gas wastewater off of a well site, or on a well site but not consisting entirely of waste (1) generated at that well site or (2) waste that will be beneficially reused at that well site, must obtain a permit to do so under the Department's residual waste regulations rather than operating under Chapters 78 or 78a.

Centralized impoundments

The final rulemaking requires all centralized impoundments to comply with permitting requirements in Subpart D, Article IX. When initially proposed, the rule included provisions to codify the Department's existing Centralized Impoundment permit program by providing technical specifications for construction and operation of centralized waste storage impoundments. The Department received significant public comment on this provision. Commenters argued that the standards set for centralized impoundments for oil and gas operations were less stringent than other Department regulations that address closure of impoundments (Ch. 289). The Department believes that centralized impoundments should be regulated in the same manner as other waste transfer facilities in the Commonwealth. Therefore, the Department has determined that all future centralized wastewater impoundments will be regulated by the Department's Waste Management Program. The rule will require oil and gas operators to comply with the residual waste management rules which contain requirements for managing residual waste properly, and these requirements apply to residual waste that is generated by any type of industrial, mining or agricultural operation. This change will ensure that the Department does not impose disparate requirements or disproportionate costs on one particular economic or extractive sector. Therefore, this provision is the least burdensome, acceptable alternative.

Ban the discharge of tophole water for a number of reasons

The final rule continues to allow operators to discharge tophole water or water in a pit as a result of precipitation onto a vegetated area capable of absorbing the water and filtering solids. Commenters argued the Department should ban the discharge of tophole water for a number of reasons. The rulemaking allows the discharge of tophole water or water in a pit from precipitation only if it includes no additives, drilling muds, regulated substances or drilling fluids other than gases or fresh water. In addition, the water must meet certain water quality standards and be discharged to an undisturbed, vegetated area capable of absorbing tophole water and filtering solids in the discharge. Tophole water or water in a pit as a result of precipitation may not be discharged to waters of the Commonwealth except in accordance with Chapters 91-93 and 95. Land application of water in accordance with this section is not expected to cause any significant environmental impact. This provision has been in effect since Chapter 78 was initially promulgated in 1989 and the Department continues to believe that it is an environmentally sound. Therefore, this provision is the least burdensome, acceptable alternative.

Disposal of residual waste - pits

Comments were received urging the Department to ban the use of all pits and to ban onsite waste disposal. The Department has amended the final rulemaking to ban the use of pits for temporary waste storage at unconventional well sites. The Department has determined that it is appropriate to prohibit this practice because it is not commonly used by unconventional operators. Additionally, the typical type and scope of use by unconventional operators is generally incompatible with technical standards for temporary pits prescribed under §78.56. As a result, unconventional operators will no longer be permitted to dispose of residual waste including contaminated drill cuttings in a pit at the well, unless the pit is authorized by a permit or other approval is obtained from the Department. Conversely, the typical type and scope of use by conventional operators is generally compatible with the technical standards for temporary pits prescribed under §78.56. The Department has allowed the disposal of residual wastes including contaminated drill cuttings in a pit at conventional well sites for decades without significant harm to public health and safety or the environment and consequently has not banned the use of pits for temporary waste storage at conventional well sites in this rulemaking. Additionally, the Department has not banned the disposal of residual waste containing contaminated drill cuttings in a pit at a conventional well site. As long as the requirements in §78.62 are met, the disposal of residual wastes containing contaminated drill cuttings at conventional well sites will not result in significant harm to public health and safety or the environment.

Allowing continued disposal of waste in a pit at a conventional well site and requiring an individual permit for disposal of waste at an unconventional well site is the least burdensome, acceptable alternative.

Seasonal high water table determination

Several comments were received stating opposition to the proposed language requiring a certified soil scientist to determine elevation of seasonal high water table. Initially, the language of this section in the proposed rulemaking required a certified soil scientist would be required to determine the elevation of the seasonal high water table. The Department revised the rulemaking to allow a certified soil scientist or "other similarly trained persons" to make the determination as well, which may represent a substantial cost savings to the operator.

As written, the rule does not exclusively require this determination to be made by a soil scientist, but instead it allows the determination to be made by a soil scientist or other similarly trained person. Since 1989, in order to ensure that they were in compliance with this requirement; conventional operators must have been conducting an evaluation of the soils beneath the bottom of their pit locations. Therefore, the Department believes that the effect of this new requirement will be to ensure that conventional operators document their determinations that their pits meet this long standing regulatory requirement prior to using them. Making this requirement even more important is the fact that once the liner is placed into the pit and the pit is put into service, it is often nearly impossible for the Department to make a determination in the field regarding compliance with this requirement. The Department does not believe that this new requirement presents any significant new burden on conventional operators. This provision does not impact operators of unconventional well sites since the rule does not allow use of pits at such well sites. Requiring operators to document that their waste disposal practices meet long-standing regulatory requirements is the least burdensome, acceptable alternative.

Borrow pits

As a result of concerns that the requirement to restore a Borrow Pit within 30 days of well permit expiration was impractical, the Department revised the restoration requirements in §§ 78.67 and 78a.67 to require Borrow Pits to be restored 9 months after completion of drilling the final well on a well site serviced by the borrow pit instead of 9 months after completion of drilling all permitted wells on the well site or 30 calendar days after the expiration of all existing well permits on well sites. This is in accordance with other restoration requirements that were similarly addressed in §§ 78.65 and 78a.65. The main concern is the fact that an activity may be finished after the growing season, in fall or winter and will not be able to achieve any vegetative growth for stabilization until the next growing season. The Department believes 9 months is a reasonable time frame to ensure the operator has an opportunity to achieve this requirement. This provision is the least burdensome, acceptable alternative.

Pipelines

The final rule addresses activities for gathering pipelines, horizontal directional drilling and well development pipelines under the jurisdiction of the Oil and Gas Program. Some commenters asserted that the subject matter addressed by these sections is extensively covered by both federal and state law, and consequently these sections are not needed. Sections 78a.68, 78a.68a and 78a.68b pertain to oil and gas gathering lines that fall under the jurisdiction of the Department's Office of Oil and Gas which are exempt from federal jurisdiction. While the Department agrees that gathering lines, horizontal directional drilling for gathering lines and well development pipelines are required to comply with 25 Pa. Code Chapters 102 and 105, the Department also deems §§ 78a.68, 78a.68a and 78a.68b necessary to address safety and environmental issues associated with gathering lines, horizontal directional drilling for gathering lines and well development pipelines due to the frequency and magnitude of these activities in the Commonwealth.

The primary focus of §§ 78a.68, 78a.68a and 78a.68b is to minimize direct impacts to waters of the Commonwealth; enhance top soil conservation and protect locations of threatened or endangered species habitat. The rulemaking is consistent with the Pennsylvania Constitution and applicable statutes and strikes a reasonable balance between protection of these natural resources and the costs occurred by the oil and gas industry.

Section 78.68 Oil and gas gathering pipelines

The rulemaking requires the use of highly visible flagging, markers or signs to be used to identify the shared boundaries of the limit of disturbance (LOD), wetlands and locations of threatened or endangered species habitat prior to land clearing. The Department received comments for and against these provisions. The Department believes it is vital to delineate special area boundaries in the field i.e. limit of disturbance, jurisdictional streams and wetlands as well as endangered species habitat otherwise unseen or not readily visible to the untrained eye, to reduce the likelihood of unintentional disturbance during clearing and grubbing or other earthmoving activities. The Department considered not requiring these sensitive areas to be clearly marked in the field during oil and gas operations. However, the Department determined that the risk of damage to sensitive areas not easily seen from large earthmoving equipment and straying beyond the permitted LOD is too great to not include this provision in the rulemaking. This requirement will greatly reduce potential impacts to these resources and it not only benefits any resources that are not impacted it also benefits any permittee that may have impacted these resources inadvertently and become subject to a compliance and enforcement case by the Department. Therefore, this is the least burdensome, acceptable alternative.

The rulemaking protects topsoil by requiring segregation of topsoil and subsoil during its excavation, storage and backfilling. The Department considered not requiring topsoil segregation because a number of comments were submitted suggesting this requirement should be removed from the rulemaking. However, the Department determined that the negative effects of not segregating topsoil would exceed the benefits of keeping this requirement, and therefore, this is the least burdensome yet acceptable alternative. Segregation of topsoil in all areas and phases is critical to successful restoration of pipeline right of ways. The practice of segregating topsoil favors industry by reducing the need, cost and the additional impact from importing topsoil to restore healthy vegetation after construction to establish permanent stabilization.

The rulemaking requires native and imported topsoil used for pipeline right of way restoration must be of equal or greater quality of the original topsoil to ensure the land is capable of supporting the uses that existed prior to earth disturbance. Some comments were against allowing any importation of topsoil. The Department considered not requiring importation of topsoil; however, this is the least burdensome yet acceptable alternative because topsoil used for restoring the pipeline right of way is of a quality capable of supporting the preexisting uses of the land.

The rulemaking requires that equipment refueling and staging areas must be out of floodways and at least 50 feet away from a body of water. The proposed setback for refueling and material staging areas from water bodies is appropriate and consistent with other regulatory requirements found in 25 Pa. Code Chapter

105. The Department received comments that the Department should allow for exceptions to the 50-foot distance restriction for material staging areas. The Department agreed and as a result, Subsection 78a.68(f) has been modified to allow for materials staging within the floodway or within 50 feet of a water body if first approved in writing by the Department. Due to the consideration and allowance for exceptions, with prior approved by the Department in writing, the Department believes this is the least burdensome, acceptable alternative.

The rulemaking requires all buried metallic gathering pipelines to be installed and placed in accordance with federal statute 49 CFR Part 192, Subpart I or 195, Subpart H relating to requirements for corrosion control. Some comments received questioned the Department's statutory authority to incorporate federal standards for pipelines into the rulemaking. Section 3218.4(a) of the 2012 Oil and Gas Act provides that "all buried metallic pipelines shall be installed and placed in operation in accordance with 49 CFR Pt. 192, Subpart I (relating to requirements for corrosion control)." Section 78.68(g) reflects this requirement. The incorporation of 49 CFR Part 195, Subpart H is included because that subpart also outlines standards for protecting pipelines against corrosion, specifically steel pipelines transporting hazardous liquids such as condensate from natural gas operations. The reference to 49 CFR Part 195, Subpart H is consistent with the intent to Section 3218.4(a) of the Oil and Gas Act to set forth standards for the installation and placement of metallic pipelines, including related corrosion control requirements. Since it is imperative to ensure that buried metallic gathering lines do not leak and result in pollution, this is the least burdensome yet acceptable alternative, as no other known alternatives achieve the same assurance of the reduced likelihood of buried metallic gathering line pipes from leaking and it is a statutory requirement.

§ 78a.68a. Horizontal directional drilling for oil and gas pipelines

The rulemaking reinforces that horizontal directional drilling for oil and gas pipelines (HDD) is subject to the regulatory requirements found in 25 Pa. Code Chapters 102 and 105 and that certain requirements specific to this section must be met. The Department received many comments in favor of this language. The Department also received comments stating that the language found in § 78a.68a is redundant since the activity is already regulated under 25 Pa. Code Chapters 102 and 105. The Department considered not including language pertaining to HDD for oil and gas pipelines in Chapter 78, the intent of the section is to provide clarity to existing requirements and address issues that frequently arise during HDD activities conducted by the oil and gas industry. Therefore, this is the least burdensome, acceptable alternative.

The rulemaking includes a requirement for a PPC plan for HDD with a site specific contingency plan that describes the measures to be taken to control, contain and collect any discharge of drilling fluids and minimize impacts to waters of the Commonwealth. The Department considered not including this requirement, however, due to the heightened potential for pollution to waters of the Commonwealth that HDD creates, a separate PPC plan is required for this specific activity. A separate PPC plan is not required for HDD activities provided that the PPC plan developed under § 78a.55 meets the requirements in section § 78a.68a which the least burdensome, acceptable alternative.

HDD activities over and adjacent to bodies of water and watercourses must be monitored for any signs of drilling fluid discharges as required in the rulemaking. Many inadvertent returns of HDD fluids express themselves hundreds of feet from the actual bore hole. Therefore, monitoring bodies of water and watercourses during HDD activities will detect impacts as soon as they occur. The Department considered not including this requirement, however, the alternative would be to not monitor for inadvertent returns which would present a significant opportunity for these instances to pollute waters of the Commonwealth without effectively seeking a solution to the problem. Therefore, this requirement is the least burdensome, acceptable alternative.

The rulemaking includes a requirement to immediately notify the Department of a HDD drilling fluid discharge or loss of drilling fluid circulation. This is consistent with the reporting requirements in § 91.33 which is the least burdensome, acceptable alternative because the rulemaking cannot be less stringent than this requirement.

HDD drilling fluid additives other than bentonite and water must be approved by the Department prior to use. All approved horizontal directional drilling fluid additives will be listed on the Department's web site to eliminate the need for preapproval prior to each use. This will ensure that HDD operators know which additives are preapproved for use without having to wait for the Department to review and approve a drilling additive. The Department considered not including this requirement; however, the Department believes this is the least burdensome, acceptable alternative because it should not be considered overly burdensome for operators to check the list provided by the Department to determine acceptable substances to be used for this activity.

§ 78a.68b. *Well development pipelines for oil and gas operations.*

Well development pipelines that transport flowback water and other wastewaters must be installed aboveground, as required in the rulemaking. The Department received comments saying that the Department should allow all well construction pipelines to be buried. The Department considered not including this requirement, but determined this is the least burdensome, acceptable alternative because buried pipelines cannot be easily inspected for leaks or damage while aboveground pipelines can be visually inspected daily when in use and if leaks or defects are observed, repairs or other effective corrective measures can be taken expeditiously and thereby reducing or avoiding an accidental pollutional event.

The rulemaking specifies that well development pipelines may not be installed through existing stream culverts, storm drain pipes or under bridges that cross streams without approval by the Department under § 105.151 (relating to permit application for construction or modification of culverts and bridges). The Department received comments against this requirement. The Department considered not including this requirement, but determined this is the least burdensome, acceptable alternative because most culvers, storm drains and bridges that cross streams are designed and sized taking the maximum anticipated flow of water into consideration. Placing well development pipelines in/under them displaces their capacity to carry their designed flow, which could lead to localized flooding as a result.

The rulemaking requires certain safety measures with well development pipelines used to transport fluids other than fresh ground water, surface water, and water from water purveyors or approved sources. These pipelines must be pressure tested prior to being placed into service and after the pipeline is moved, repaired or altered. They must have shut off valves, check valves or other methods of segmenting the pipeline placed at designated intervals that prevent the discharge of more than 1,000 barrels of fluid. They may not have joints or couplings on segments that cross waterways unless secondary containment is provided. They cannot be used to transport flammable materials. The STRONGER organization recommends that state programs should address the integrity of pipelines for transporting and managing hydraulic fracturing fluids off the well pad. The Department received comments that endorsed these provisions and comments that were against their implementation. The Department considered not including these requirements, however, the Department believes this is the least burdensome, acceptable alternative because these safety measures are necessary to protect the environment by providing mechanisms that help identify their locations; isolate sections that are compromised, minimizes direct leaks into waterways and eliminates the risk of fires. Without these requirements there would be many more opportunities for pollution to occur to waters of the Commonwealth than if they are kept in the rulemaking.

The rulemaking requires well development pipelines to be removed when the well site is restored. The Department received comments requesting that these pipelines should be allowed to remain to transport and reuse production water from the well site. Well development pipelines are meant to be temporary and used for the sole purpose of well development activities at a well site. Well development pipelines need to be removed when the well site get restored in accordance with § 78a.65. The Department considered not including this requirement, however, permanent pipelines used for transportation of fluids is beyond the scope of this rulemaking, therefore this requirement is the least burdensome, acceptable alternative.

The rulemaking requires the operator to maintain certain records regarding well development pipelines, including their location, type of fluids transported, the approximate time of installation, pressure test results, defects and repairs. The records need to be retained for a year after their removal and be made available to the Department upon request. The Department received a comment that well development records should be retained by operators for two years after their removal. The Department believes one year is a sufficient amount of time for record retention due to the temporary nature of these pipelines. The Department considered the additional year of record retention but determined that there was not a significant benefit to this, therefore the requirement in the rulemaking is the least burdensome, acceptable alternative.

The rulemaking requires operators to obtain Department approval for well development pipelines in service for more than a year. The Department believes that a well development pipeline that is in service for over a year becomes more than a temporary use and wants to know about its location and use. Due to the fact that this is a requirement to notify the Department, it is the least burdensome alternative which will enable temporary pipelines to remain in place beyond the one-year limitation of the requirement in the rulemaking for well development pipelines.

Water Management Plans

The Department received comments urging the Department to include conventional operations to be included in the requirement to develop water management plans. Water Management Plans are a requirement of Act 13 of 2012. This regulation codifies existing requirements to protect quality and quantity of water sources in the Commonwealth, including freshwater resources, from adverse impacts to the watershed considered as a whole from potentially inappropriate withdrawals of water. This final-form rulemaking mirrors most of the requirements of the Susquehanna River Basin Commission and the Delaware River Basin Commission to ensure that requirements are consistent statewide, regardless of which river basin an operator withdraws water from, as defined in the rulemaking this only applies to unconventional operations. The Department does not believe that the scope of water use by the conventional oil and gas industry warrants a requirement to develop Water Management Plans; therefore, this is the least burdensome, acceptable alternative.

Road-spreading of brine for dust control and road stabilization

Commenters recommended the complete prohibition of spreading of brine on roads for dust control. The Department considered a complete prohibition of the road spreading of brine and determined that unconventional brines may not be spread on roads for any reason. Conventional brine may be spread on roads for dust control and road stabilization under controlled conditions that require the brine to meet certain chemical parameters for use and sets limits on the application location, rate, and duration. Due to the consideration or road spreading of brines and the determination that if, when done by the conventional industry, under the manner detailed in the rulemaking, this is the least burdensome, acceptable alternative.

Pre-wetting, anti-icing and de-icing

Commenters recommended the complete prohibition of brine being used to de-ice roads. The Department disagrees with the comment. Application rates, location of application sites relative to water bodies, site characteristics are designed/selected to prevent runoff from reaching waters of the Commonwealth. Production brines from conventional wells have a history of use as pre-wetting, anti-icing and de-icing agents. Production water from unconventional wells does not have this same history and the Department believes it is prudent to err on the side of protection of public health and safety and the environment until it can be demonstrated otherwise. Due to the consideration of road de-icing with brines and the determination that if, when done by the conventional industry, under the manner detailed in the rulemaking, this is the least burdensome, acceptable alternative.

Question 27

(27) In conducting a regulatory flexibility analysis, explain whether regulatory methods were considered that will minimize any adverse impact on small businesses (as defined in Section 3 of the Regulatory Review Act, Act 76 of 2012), including:

a) *The establishment of less stringent compliance or reporting requirements for small businesses;*

- All operators regardless of size will have the ability to request alternative practices to the regulation with regard to pits, waste disposal, and impoundments. An operator may request to vary from the regulation if they can show that the practice is equivalent or superior for environmental protection.

- Under § 78.15, the required setback for drilling conventional oil or gas wells near buildings and water supplies is less than half of that required by unconventional wells.

- Under § 78.52a, smaller search areas, still considerate of risk, are defined for shallow oil operators under the area of review provision. This provision is less stringent because the search areas are smaller than search areas required for typical unconventional wells.

- Under § 78.55, emergency response plans are not required for conventional well sites. Only a site specific Preparedness, Prevention and Contingency (PPC) Plan is required. This provision is less stringent because unconventional operations are required to prepare and implement an emergency response plan in addition to a PPC plan.

- Under § 78.56, pits are allowed for temporary storage of wastes on well sites. This provision is less stringent because pits may not be used at unconventional well sites under § 78a.56.

- Under § 78.56, measures to prevent unauthorized access by third parties is not required for tank valves and access lids. A requirement to install measures such as locking tank lids and valves to prevent unauthorized access by third parties at conventional well sites was initially proposed but was removed from this section in the final-form rulemaking. This provision is less stringent because measures to prevent unauthorized access by third parties are required at unconventional well sites.

- Under § 78.56, signs on the tank or other approved storage structure identifying the contents and an appropriate warning of the contents is not required. This provision is less stringent because signs on the tank or other approved storage structure identifying the contents and appropriate warning of the contents are required at unconventional well sites.

- Under § 78.56, pits with an aerial extent of 3,000 ft^2 and a total volume of 125,000 gallons may be constructed and utilized at conventional well sites under a permit-by-rule. Operators that propose to utilize pits larger than this must obtain approval from the Department prior to construction. Initially, the rule included a requirement that the interior slopes of pits had to be 2 horizontal to 1 vertical or flatter. The Department has revised § 78.56 to remove minimum slope requirements for a pit with a footprint less than 3,000 ft^2 or volume less than 125,000 gallons of capacity. This provision is less stringent because, smaller pits typically used by small business can continue to be constructed under the permit-by-rule structure. Some conventional operators may choose to construct a larger pit as required by the type of well or stimulation procedure they are undertaking. For pits larger than prescribed above, the Department believes that the environmental risk is sufficient to require anyone, including small businesses, who may wish to construct such a pit to obtain an individual authorization from the Department.

- Under § 78.57, measures to prevent unauthorized access by third parties is not required for tanks storing brine or other fluids produced during operation of the well. This provision is less stringent because all new, refurbished or replaced tanks storing brine or other fluids produced during operation of the well must be reasonably protected from unauthorized acts of third parties.

- Under § 78.61, drill cuttings from below the casing seat may be disposed either in a pit that meets the § 78.62 requirements or by land application in accordance with 78.63. This provision is less stringent because it allows conventional operators to continue to dispose of contaminated drill cuttings and drill cuttings from below the casing seat under a permit by rule structure while unconventional operators must obtain an individual permit from the Department prior to disposing of such wastes on the well site.

- Under § 78.65, drilling supplies and equipment (not needed for production) stored at conventional well sites with the written consent of the surface landowner do not need secondary containment. Supplies and equipment not needed for production stored on unconventional well sites must be stored within secondary containment, as appropriate.

b) *The establishment of less stringent schedules or deadlines for compliance or reporting requirements for small businesses;*

Many of the required documents and test results demonstrating compliance are to be submitted on a timeframe that will not cause a hindrance to operation timelines. Examples include drill cuttings sample results being submitted with the site restoration report instead of requiring a Department review and approval prior to on-site disposal. Another example is seasonal high groundwater determinations for waste pits certifications being submitted with the site restoration report.

- Under § 78.52, all sample results pertaining to the well of concern to be submitted to the Department electronically by the operator 10 days prior to commencement of drilling of the well. This provision gives the operator control of when sample results must be submitted to the Department and allows operators to collect samples closer to the actual time of drilling. This provision is less stringent than the existing requirement to submit all pre-drilling or pre-alteration survey data within 10 days of receipt.

- Under § 78.56, operators are required to notify the Department at least 3 business days before the construction of a pit with footprint greater than 250 square feet, but in case of re-notification 3-day advance notice is not required. This provision is less stringent because it does not apply operators that use small pits.

- Under § 78.57, tanks storing brine or other fluids produced during operation of the well must be inspected by the operator at least once per calendar quarter. This provision is less stringent because storage tanks used at unconventional well sites must be inspected at least once per month.

c) The consolidation or simplification of compliance or reporting requirements for small businesses;

For consolidation or simplification of compliance for all operators, one of the major intents of this regulation is for Chapter 78 to be the one source for regulatory requirements for this industry. Other programs and regulations have requirements regarding oil and gas operations, which make it difficult for operators to know which regulations apply to them. Additionally, if a permit applicant obtains an erosion and sediment control permit under Pa Code Chapter 102, proof of consultation with the Pennsylvania Natural Heritage Program as part of the well permit application shall be deemed as being met. Another measure aimed at simplification is the Department's commitment to listing the pre-approved solidifiers, modular containment systems, and wastewater processing facilities online to eliminate redundancy and increase business efficiencies.

Electronic reporting will consolidate or simplify reporting requirements for all operators. The Department has also designed these proposed regulations to include additional reporting requirements on reports that are already provided to the Department. For example, pit testing results can be included on the operator's site restoration report.

- Under § 78.15, the required setback for drilling conventional oil or gas wells near buildings and water supplies is less than half of that required by unconventional wells.

- Under § 78.15(f), water well, surface water intake, reservoir or other water supply extraction points used by a water purveyor are not included in the list of public resources that must be considered when obtaining a well permit while unconventional operators must consider these public resources in accordance with Section 3215(c)(6) of the 2012 Oil and Gas Act.

- Under § 78.55, emergency response plans are not required. Only a Preparedness, Prevention and Contingency (PPC) Plan is required. This provision is simplified because unconventional operations are required to prepare and implement an emergency response plan in addition to a PPC plan.

- Under § 78.56, pits with an aerial extent of 3,000 ft^2 and a total volume of 125,000 gallons may be constructed and utilized at conventional well sites under a permit-by-rule. Operators that propose to utilize pits larger than this must obtain approval from the Department prior to construction. Initially the rule included a requirement that the interior slopes of pits had to be 2 horizontal to 1 vertical or flatter. The Department has revised § 78.56 to remove minimum slope requirements for a pit with a footprint less than 3,000 ft^2 or volume less than 125,000 gallons of capacity. This provision is simplified because smaller pits typically used by small business can continue to be constructed under the permit-by-rule structure. Some conventional operators may choose to construct a larger pit as required by the type of well or stimulation procedure they are undertaking. For pits larger than prescribed above, the Department believes that the environmental risk is sufficient to require anyone, including small businesses, who may wish to construct such a pit to obtain an individual authorization from the Department.

- Under § 78.56, operators are required to notify the Department at least 3 business days before the construction of a pit with a footprint greater than 250 square feet, but in case of re-notification, a 3-day advance notice is not required. This provision is simplified because it does not apply operators that use small pits.

- Under § 78.56, the Department will maintain a list of approved modular storage structures on its website so that an operator needs to request only the siting approval from the Department for use of approved modular storage structure. This provision is simplified from existing practice where an approval is required each time a modular aboveground storage structure is used.

- Under § 78.56, the Department will maintain a list of approved alternative liners on its website. This provision allows a simplified way to identify approved alternative liners.

- Under § 78.57, tanks storing brine or other fluids produced during operation of the well must be inspected by the operator at least once per calendar quarter. This provision is simplified because storage tanks used at unconventional well sites must be inspected at least once per month.

- Under § 78.58, approval from the Department is not required for mixing fluids with freshwater, aerating fluids and filtering solids from fluids. This provision simplifies existing practice of requiring approval for all forms of onsite processing.

- Under § 78.61(d), the Department will maintain a list of approved solidifiers so the operator does not need to request approval from the Department for use of approved solidifiers. This provision will simplify existing process by making information regarding approved solidifiers more easily available.

d) *The establishment of performance standards for small businesses to replace design or operational standards required in the regulation;*

Most of the regulations are based upon performance standards with protection of the environment as the goal. The Department believes the performance standards in these regulations will promote cost savings to operators and new innovation for small businesses, especially those in the supply chain.

An example of performance based standards is the expanded temporary storage regulations to allow for modular storage structures to be utilized. There are many possible designs of these storage structures for companies to offer to industry. The operators can use liners other than 30 mils thick for pits used for temporary storage if the Department approved the alternative liner. Approval may be granted if the manufacture demonstrates that the alternative thickness is at least as protective as a 30 mil liner. The newly proposed onsite processing regulations use performance based standards, which allows for operators to choose from various wastewater treatment techniques to meet their particular needs. The operator can request the Department for approval to use solidifiers or other alternative practices for the disposal of uncontaminated drill cuttings as well as residual waste, including contaminated drill cuttings. The newly added containment systems and practices for unconventional well sites regulations also have performance based standards small businesses are already taking advantage of in promoting their products to aid industry with meeting these standards.

Under 78.65, a written site restoration plan is not required. Operators may develop a written site restoration plan to comply with requirements in Chapter 102, as appropriate.

Specific requirements relating to oil and gas gathering lines, horizontal directional drilling for oil and gas pipelines requirements and well development pipelines for oil and gas operations requirements are not included in Chapter 78. These requirements remain in Chapter 78a.

The requirements to develop a water management plan are not included in Chapter 78.

Road spreading of brine from conventional oil and gas wells for dust control and road stabilization and the use of bring for pre-wetting, anti-icing and de-icing is allowed. Brines from unconventional gas wells may not be spread on roadways for any reason.

e) The exemption of small businesses from all or any part of the requirements contained in the regulation.

Conventional well operations make up the majority of the small businesses impacted by this regulation. By nature of their processes, they are much smaller in scope and they generate far less waste than unconventional drilling, therefore the potential impact to the environment is significantly less. This has been taken into consideration while these regulations were being developed, which resulted in conventional operator exemptions from several sections of this regulation, including: certain PPC requirements, monitoring or fencing requirements for pits, signage requirements for storage facilities, seasonal high groundwater determinations for temporary pits, notification of installation of pit liners, and containment systems and practices. Many activities that have additional requirements only apply to unconventional operations. Conventional well operators were only included in provisions that were deemed necessary to protect the environment regardless of the type or size of the oil and gas operation.

- Under § 78.15, the required setback for drilling conventional oil or gas wells near buildings and water supplies is less than half of that required by unconventional wells.

- Under § 78.15(f), water well, surface water intake, reservoir or other water supply extraction points used by a water purveyor are not included in the list of public resources that must be considered when obtaining a well permit.

- Under § 78.55, emergency response plans are not required. Only a Preparedness, Prevention and Contingency (PPC) Plan is required.

- Under § 78.56, pits are allowed for temporary storage of wastes on well sites. Pits may not be used at unconventional well sites under § 78a.56.

- Under § 78.56, pits with an aerial extent of 3,000 ft^2 and a total volume of 125,000 gallons may be constructed and utilized at conventional well sites under a permit-by-rule. Operators that propose to utilize pits larger than this must obtain approval from the Department prior to construction. Initially the rule included a requirement that the interior slopes of pits had to be 2 horizontal to 1 vertical or flatter. The Department has revised§ 78.56 to remove minimum slope requirements for a pit with a footprint less than 3,000 ft^2 or volume less than 125,000 gallons of capacity. This provision is less stringent because, smaller pits typically used by small business can continue to be constructed under the permit-by-rule structure. Some conventional operators may choose to construct a larger pit as required by the type of well or stimulation procedure they are undertaking. For pits larger than prescribed above, the Department believes that the environmental risk is sufficient to require anyone, including small businesses, who may wish to construct such a pit to obtain an individual authorization from the Department. Operators that construct smaller pits are exempt from this requirement.

- Under § 78.62, residual waste generated by the drilling or stimulation of an oil or gas well can be disposed in pits. Drill cuttings produced by the drilling of unconventional wells may only be disposed in a pit on the site if an individual disposal permit is first obtained from the Department.

- Under § 78.63, residual waste generated by the drilling or stimulation of an oil or gas well can be disposed by land application. Drill cuttings produced by the drilling of unconventional wells may only be disposed by land application on the site if an individual disposal permit is first obtained from the Department.

- Under § 78.65, drilling supplies and equipment (not needed for production) stored at conventional well sites with the written consent of the surface landowner do not need secondary containment. Supplies and equipment not needed for production stored on unconventional well sites must be stored within secondary containment as appropriate.

- Under § 78.65, a written site restoration plan is not required. Operators may need to develop a written site restoration plan to comply with requirements in Chapter 102, as appropriate.

- Requirements relating to oil and gas gathering lines, horizontal directional drilling for oil and gas pipeline requirements and well development pipelines for oil and gas operations requirements are not included in Chapter 78. These requirements remain in Chapter 78a.

- The requirements to develop a water management plan are not included in Chapter 78.

These issues were also discussed generally in the responses to Questions 15 and 25 as well.

Question 28

(28) If data is the basis for this regulation, please provide a description of the data; explain in detail how the data was obtained, and how it meets the acceptability standard for empirical, replicable and testable data that is supported by documentation, statistics, reports, studies or research. Please submit data or supporting materials with the regulatory package. If the material exceeds 50 pages, please provide it in a searchable electronic format or provide a list of citations and internet links that, where possible, can be accessed in a searchable format in lieu of the actual material. If other data was considered but not used, please explain why that data was determined not to be acceptable.

In development of this regulation, the Department reviewed the following data:

The Pennsylvania Oil and Gas Technologically Enhanced Naturally Occurring Radioactive Material (TENORM) Study Report - This is a report of the findings of a comprehensive study conducted by the Department on oil and gas related TENORM. The report is available at the following link.

http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-105822/PA-DEP-TENORM-Study_Report_Rev._0_01-15-2015.pdf

The oil and gas production reports - Operators are required to periodically submit both waste and product production reports to the Department. The data is available at the following link.

https://www.paoilandgasreporting.state.pa.us/publicreports/Modules/Welcome/Welcome.aspx

The Workload Report - This report summarizes well permitting and drilling in Pennsylvania. The most recent report is available at the following link.

http://files.dep.state.pa.us/OilGas/BOGM/BOGMPortalFiles/OilGasReports/2015/WEBSITE_Weekly_Report_for_Last_Week.pdf

The Well Pad Report – this report provides information regarding the number of well pads and associated wells in Pennsylvania and is available at the following link.

http://www.depreportingservices.state.pa.us/ReportServer/Pages/ReportViewer.aspx?/Oil_Gas/Well_Pads

The oil and gas compliance report – This report provides information regarding violations by oil and gas operators in Pennsylvania and is available at the following link.

http://www.depreportingservices.state.pa.us/ReportServer/Pages/ReportViewer.aspx?/Oil_Gas/OG_Compliance

In addition, the Department conducted a shale cuttings study in 2012. A summary is provided below and the full data set will be provided as a separate electronic file.

White Paper: Chemical Characterization of Leachate from Drill Cuttings Produced by Unconventional Drilling in the Marcellus Shale Formation to Determine Compliance with Current Regulatory Requirements for Onsite Disposal.

Short Title: Marcellus Shale Drill Cutting Leachate Compliance with Current Onsite Disposal Requirements

Goals:

1) Identify the chemical characteristics of leachate from Marcellus shale drill cuttings.

2) Determine if leachate from Marcellus shale drill cuttings meet current onsite disposal regulations.

Background: Current regulation relative to onsite disposal of contaminated drilling cuttings is contained in Chapter 78.62(b) which states:

A person may not dispose of residual waste, including contaminated drill cuttings, at the well site unless the waste meets the following requirements:

(1) The concentration of contaminants in the leachate from the waste does not exceed 50% of the maximum concentration in § 261.24 Table I (relating to characteristic of toxicity).

(2) The concentration of contaminants in the leachate from the waste does not exceed 50 times the primary maximum contaminant level in effect under § 109.202 (relating to State MCLs, MRDLs and treatment technique requirements).

(3) For other health related contaminants, the concentration of contaminants in the leachate from the waste does not exceed 50 times the safe drinking water level established by the Department.

Item 1 above refers to § 261.24 of 40 CFR and specifically to Table 1 which list 40 contaminants tested for in the TCLP (Toxicity Characteristics Leaching Procedure and Characteristic Wastes) The TCLP is a test used to detect contaminants in leachate. See Table 1 – Maximum Concentration of Contaminants for Toxicity Characteristics. Fifty percent of the maximum concentration of contaminants in this list establishes some of the action levels for the contaminants in leachate from drill cutting waste to be disposed of on the well site. Items 2 and 3 above refer to § 109.202 of 25 Pa. Code Chapter 109, State MCLs, MRDLs and treatment technique requirements. This section incorporates by reference the primary MCLs in the National Primary Drinking Water Regulations, at 40 CFR Part 141, Subparts B and G (relating to maximum contaminant levels) as State MCLs, under authority of section 4 of the Pennsylvania Safe Drinking Water Act (35 P. S. § 721.4), unless other MCLs are established by regulations of the Department. Fifty times the primary maximum contaminant levels and the safe drinking water levels establishes additional action levels for contaminates in leachate from drill cutting waste to be disposed of on the well site.

Process: Samples are collected by Water Quality Specialists experienced in collecting, preparing, preserving and delivering or shipping samples for analysis to the State Bureau of Laboratories in Harrisburg, Pennsylvania. Proper sampling collection, preservation, and handling techniques are required to ensure data quality. Relevant information such as the well permit number, sample collector's name and number, time and date of sample collection, the municipal and county location, facility name and address and specific sample collection locations (i.e. cuttings conveyor, shaker, drill pit, etc.) is noted. The samples are analyzed at the Bureau of Laboratories for specific analytes identified in the regulations. The Bureau of Laboratories selects approved analytical methods and techniques appropriate for the analytes of interest and level of sensitivity needed for comparison with the established action levels. Established action levels in the regulations require inorganic, volatile organic and semi-volatile organic chemical analysis groups. Proper analytical methods must be selected and preformed to ensure accurate chemical characterization. Analytical reports prepared by the Bureau of Laboratories are delivered for analysis.

Analysis: Analysis of Bureau of Laboratories Analytical Reports includes compilation of the raw test data into an Excel spreadsheet to facilitate comparison of the analytical results with the regulatory action levels. Each analyte is assigned to an analysis group based on its classification as inorganic, volatile organic or semi-volatile organic. Each regulatory action level is based on an MCL established under either 40 CFR 261.24 or Section 109.202 as described previously. Each analysis group, respective analytes and their regulatory action levels are presented in Table 2.

Results: Each analysis result from the Bureau of Laboratory is compared with its respective action level to determine if the action level has been exceeded. Table 3 shows the results of the comparison for the inorganic analysis group and the regulatory action levels to determine if action levels were exceeded. For each analyte in the inorganic analysis group, no action level is exceeded and of the 178 samples taken, 55 detected the analyte of interest.

Table 4 shows the results of the comparison for the semi-volatile and volatile organic analysis groups. For all analytes in both the semi-volatile and volatile analysis group, no action level is exceeded and of the 500 samples taken, 5 detected the analyte of interest.

It is difficult to apply the regulations to pH. The MCL for pH is “secondary” at 6.5-8.5 and according to Chapter 109, represents a reasonable goal for drinking water. Additionally, pH is measured on a logarithmic scale which goes from 0-14 so the “50 times” rule cannot be applied. The range of the final pH from the TCLP is reported as 4.99 to 8.25 with a mean pH of 5.80.

Summary: Based on the results of this study, drill cuttings from unconventional drilling in the Marcellus shale meet Chapter 78 requirements to dispose of the contaminated drill cuttings on the well site.

Table 1 – Maximum Concentration of Contaminants for the Toxicity Characteristic

EPA HW No.	Contaminant	CAS Number	Regulatory Level (mg/l)
D004	Arsenic	7440-38-2	5.0
D005	Barium	7440-39-3	100.0
D016	Benzene	71-43-2	0.5
D006	Cadmium	7440-43-9	1.0
D019	Carbon Tetrachloride	56-23-5	0.50
D020	Chlordane	57-74-9	0.03
D021	Chlorobenzene	108-90-7	100.0
D022	Chloroform	67-66-3	6.0
D007	Chromium	7440-47-3	5.0
D023	o-Cresol	95-48-7	200.0
D024	m-Cresol	108-39-4	200.0
D025	p-Cresol	106-44-5	200.0
D026	Cresol	************	200
D016	2,4-D	94-75-7	10.0
D027	1,4-Dichlorobenzene	106-46-7	7.5
D028	1,2-Dichloroethane	107-06-2	0.50
D029	1,1-Dichloroethylene	75-35-4	0.70
D030	2,4-Dinitrotoluene	121-14-2	0.13
D012	Endrin	72-20-8	0.02
D031	Heptachlor (and its epoxide)	76-44-8	0.008
D032	Hexachlorobenzene	118-74-1	0.13
D033	Hexachlorobutadiene	87-68-3	0.13
D034	Hexachloroethane	67-72-1	3.0
D008	Lead	7439-92-1	5.0
D013	Lindane	58-89-9	0.4
D009	Mercury	7439-97-6	0.2
D014	Methoxychlor	74-43-5	10.0
D035	Methyl Ethyl Ketone	78-93-3	200.0
D036	Nitrobenzene	98-95-3	2.0
D037	Pentachlorophenol	87-86-5	100.0
D038	Pyridine	110-86-1	5.0
D010	Selenium	7782-49-2	1.0
D011	Silver	7440-22-4	5.0
D039	Tetrachloroethylene	127-18-4	0.7
D015	Toxaphene	8001-35-2	0.5
D040	Trichloroethylene	79-01-6	0.50
D041	2,4,5-Trichlorophenol	95-95-4	400.0
D042	2,4,6-Trichlorophenol	88-06-2	2.0
D017	2,4,5-TP (Silvex)	93-72-1	1.0
D043	Vinyl Chloride	75-01-4	0.20

Table 2 – Analysis Groups, Analytes, MCLs and Corresponding Action Levels

Analysis Group/Analytes	TCLP Table 1 MCL MG/L	Federal Drinking Water MCL MG/L	109.202 Action Levels MCL x 50 MG/L	261.24 Action Levels 50% 0f TCLP (Table 1) MG/L
Inorganic				
Arsenic	5.0	0.01	0.5	2.5
Barium	100.0	2	100	50
Cadmium	1.0	0.005	0.25	0.5
Chromium	5.0	0.1	5	2.5
Iron		0.3		
Lead	5.0	0.015	0.75	2.5
Mercury	0.2	0.002	0.1	0.1
Selenium	1.0	0.05	2.5	0.5
Silver	5.0	10	500	2.5
Strontium				
Semi-volatile Organic				
2,4,5-Trichlorophenol	400			200
2,4,6-Trichlorophenol	2			1
Cresol (3&4-Methylphenol)	200			100
Hexachlorobenzene	0.13	0.001	0.05	0.065
Hexachloroethane	3			1.5
Nitrobenzene	2			1
o-Cresol (2-Methylphenol)	200			100
Pyridine	5			2.5
Benzopyrene (Benzo (a) Pyrene)	0.0002			0.0001
2,4-Dinitrotoluene	0.13			0.065
Volatile Organic				
1,1-Dichloroethylene (1,1-Dichloroethene)	0.007			0.0035
1,2-Dichloroethane	0.005			0.0025
1,4-Dichlorobenzene	7.5			3.75
Carbon Tetrachloride	0.005			0.0025
Chlorobenzene	100	0.1	5	50
Chloroform	6			3
Hexachlorobutadiene	0.5			0.25
Methyl Ethyl Ketone (MEK)	200			100
Tetrachloroethylene (Tetrachloroethene)	0.7	0.005	0.25	0.35
Trichloroethylene (Trichloroethene)	0.5	0.005	0.25	0.25
Chloroethene (Vinyl Chloride)	0.2	0.002	0.1	0.1
Benzene	0.5	0.005	0.25	0.25
Ethylbenze		0.7	35	
Ethylene Dibromide (1,2-Dibromoethane)		0.00005	0.0025	
Styrene	0.1			0.05

Table 3 Inorganic Analysis Action Level Exceedance Results

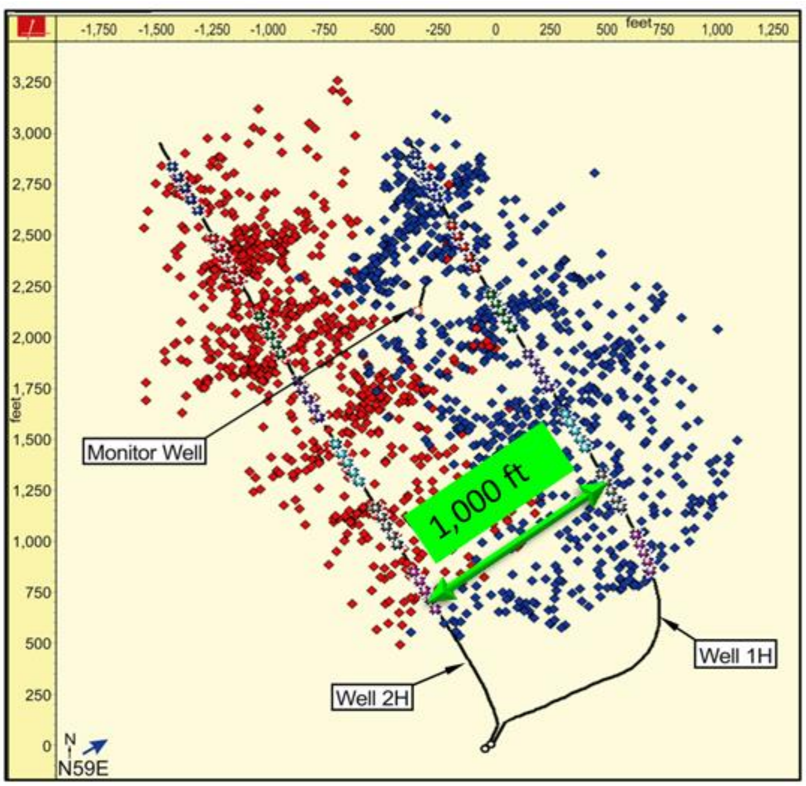
Analyte	Number of Samples Taken	Number of Samples With Analyte Detection	Action Level Exceeded Under Section 109.202	Action Level Exceeded Under Section 261.24
Arsenic	19	1	0	0
Barium	19	18	0	0
Cadmium	19	2	0	0
Chromium	19	2	0	0
Iron	14	8	0	0
Lead	19	10	0	0
Mercury	17	0	0	0
Selenium	19	0	0	0
Silver	19	0	0	0
Strontium	14	14	0	0
Total	178	55	0	0

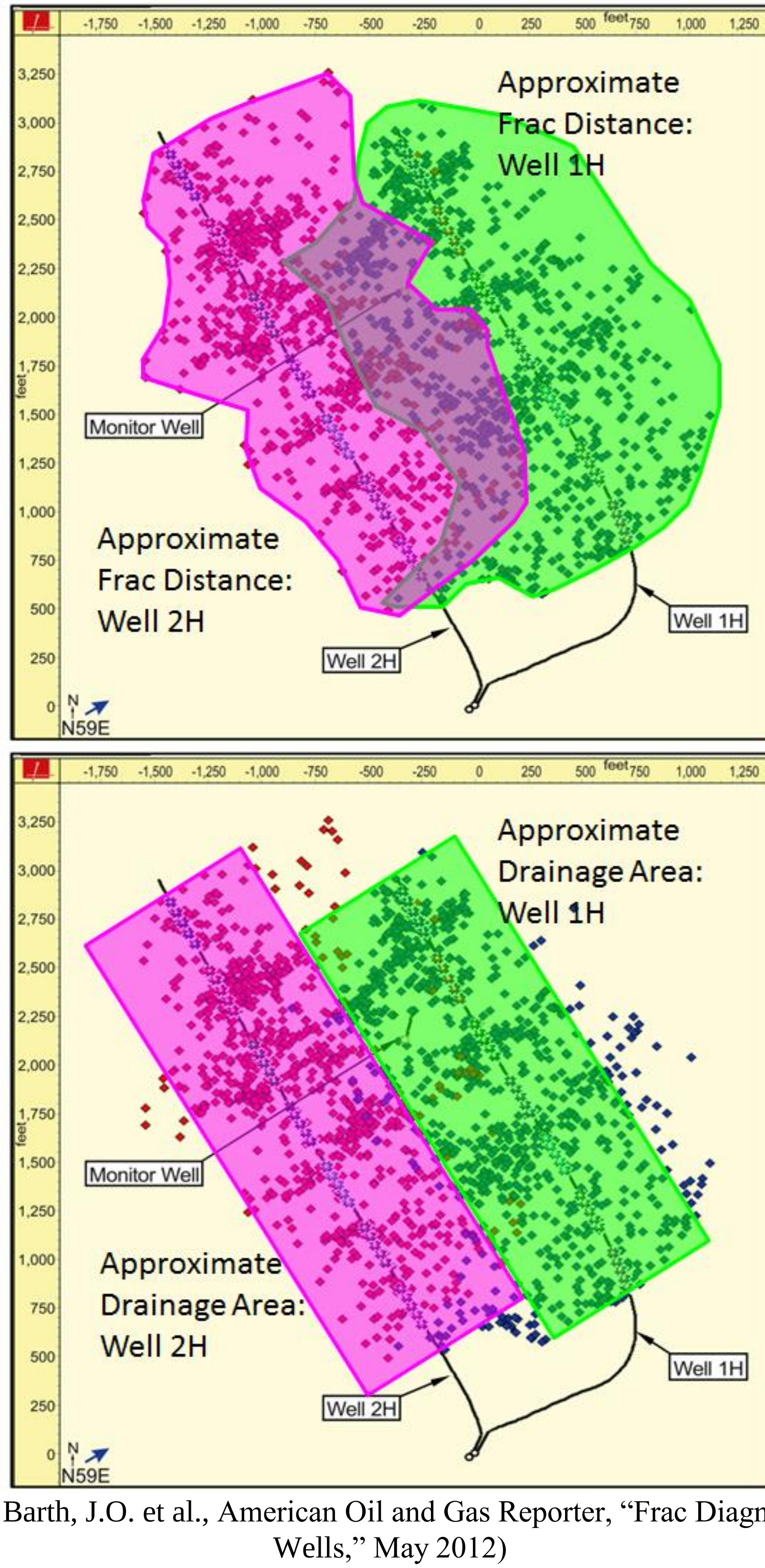
Table 4 Organic Analysis Action Level Exceedance Results

Analytes	Number of Samples Taken	Number of Samples With Analyte Detection	Action Level Exceeded Under Section 109.202	Action Level Exceeded Under Section 261.24
Semi-volatile Organic				
2,4,5-Trichlorophenol	20	0	0	0
2,4,6-Trichlorophenol	20	0	0	0
Cresol (3&4-Methylphenol)	20	0	0	0
Hexachlorobenzene	20	0	0	0
Hexachloroethane	20	0	0	0
Nitrobenzene	20	0	0	0
o-Cresol (2-Methylphenol)	20	0	0	0
Pyridine	20	1	0	0
Benzopyrene (Benzo (a) Pyrene)	20	0	0	0
2,4-Dinitrotoluene	20	0	0	0
Volatile Organic				
1,1-Dichloroethylene (1,1-Dichloroethene)	20	0	0	0
1,2-Dichloroethane	20	0	0	0
1,4-Dichlorobenzene	20	0	0	0
Carbon Tetrachloride	20	0	0	0
Chlorobenzene	20	0	0	0
Chloroform	20	0	0	0
Hexachlorobutadiene	20	0	0	0
Methyl Ethyl Ketone (MEK)	20	0	0	0
Tetrachloroethylene (Tetrachloroethene)	20	0	0	0
Trichloroethylene (Trichloroethene)	20	0	0	0
Chloroethene (Vinyl Chloride)	20	0	0	0
Benzene	20	3	0	0
Ethylbenze	20	1	0	0
Ethylene dibromide (1,2-Dibromoethane)	20	0	0	0
Styrene	20	0	0	0
Total	500	5	0	0

Regarding the area of review requirements, the Department determined it was important to study hydraulic fracturing communication incidents, review available data and evaluate industry practices in the state to inform the area of review regulation, as inappropriate investigation distances have the potential to unnecessarily increase the cost of implementation or inadequately address risk if excessive or not conservative enough, respectively.

In general, oil and gas wells are spaced to minimize interference during production. In other words, roughly half of the reservoir volume between wells is drained by one of the wells, while the remaining volume is accessed by the other well in each adjacent pair. Because of this, well spacing provides insight regarding a well's expected drainage area and, thus, how far fractures may propagate away from perforations or notches. However, it does not provide a complete picture, as fractures are known to extend beyond a well's ultimate drainage area, as it is not possible to deliver proppant to fracture tips. Because of this, a well's potential to hydraulically communicate beyond its drainage area is well known. This concept is illustrated in the following three figures that depict microseismic data recorded at a Marcellus shale well in Pennsylvania (Barth, J.O. et al., American Oil and Gas Reporter, "Frac Diagnostics Key in Marcellus Wells," May 2012). The first image is the plotted coordinate data of the microseismic signals. The latter two images show the fracture propagation distances and the approximate drainage areas based on the practice of minimizing interference between adjacent wells.

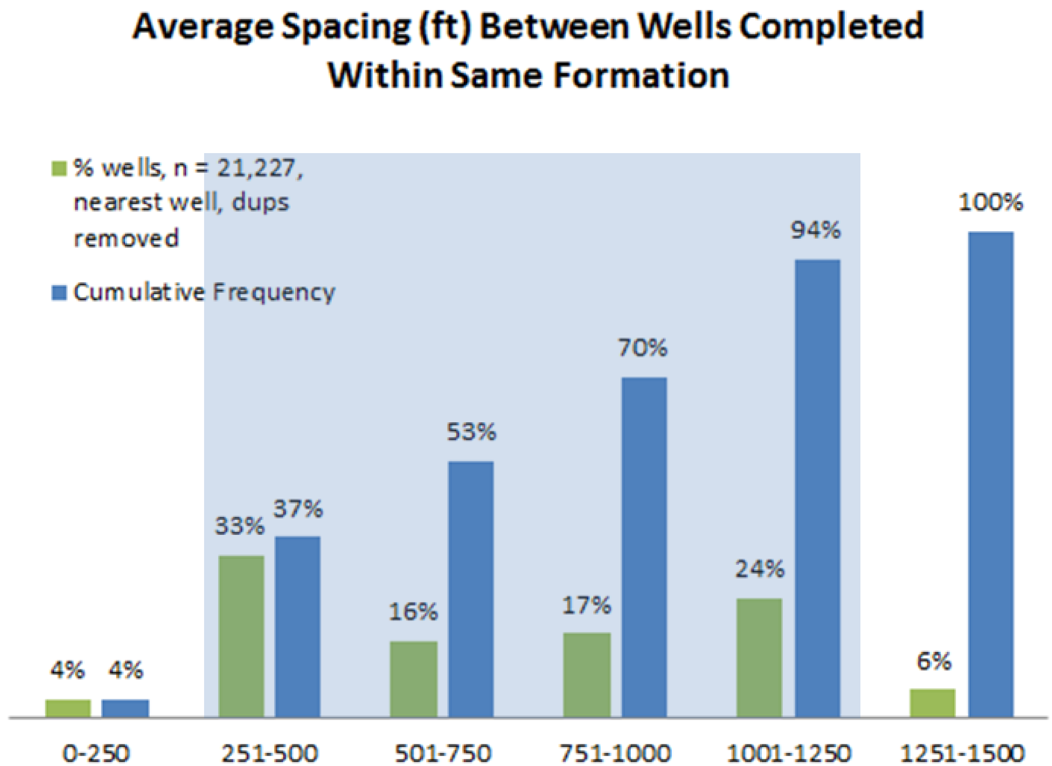




(Source: adapted from Barth, J.O. et al., American Oil and Gas Reporter, "Frac Diagnostics Key in Marcellus Wells," May 2012)

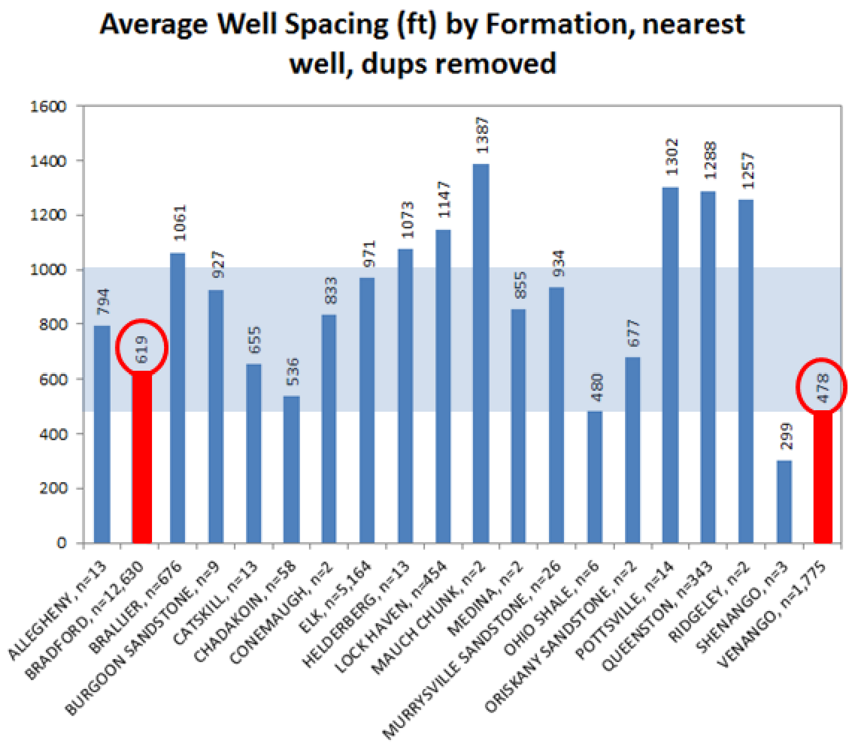
The preceding images demonstrate that a review area solely based on drainage area would be insufficient with regard to identifying the area over which hydraulic fractures are likely to extend.

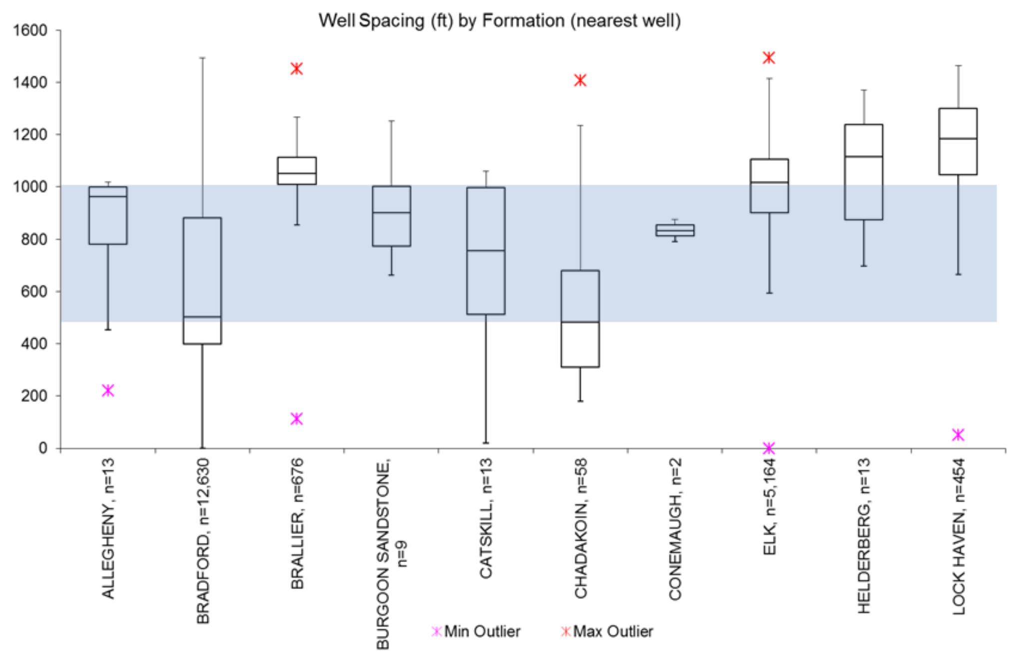
Conventional operators in the state generally do not collect microseismic data. However, as shown above, well spacing data are informative with regard to fracture propagation distances. Available spacing information was studied as a proxy for fracture propagation distances (DCNR EDWIN and DEP eFACTs, 2015). Well location and formation data were downloaded from the state's two main oil and gas databases, EDWIN and eFACTs. After removing wells from the dataset with locational discrepancies and eliminating duplicate pairings, a total of 21,227 records were used to develop a frequency distribution diagram of well spacing. The final dataset includes wells within 1,500 feet of each other that have the same operator and are completed in the same formation.

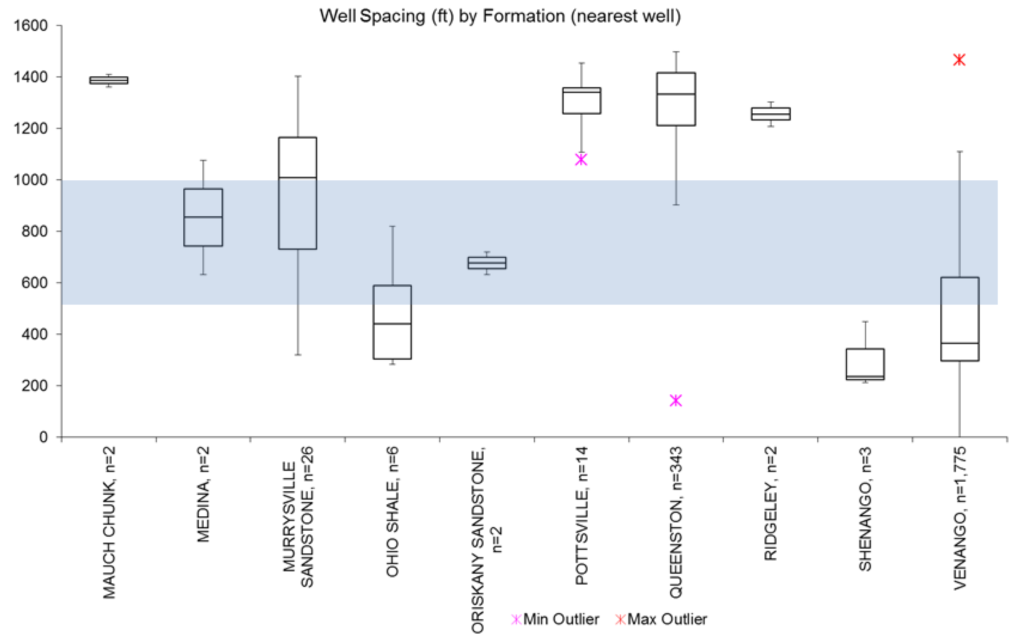


(Source: DCNR EDWIN and DEP eFACTs, 2015)

The figure illustrates that the majority of wells in the dataset have average spacings that range between 250 and 1,250 feet. The data were further analyzed on a formation-by-formation basis and this information is presented in the next three figures.

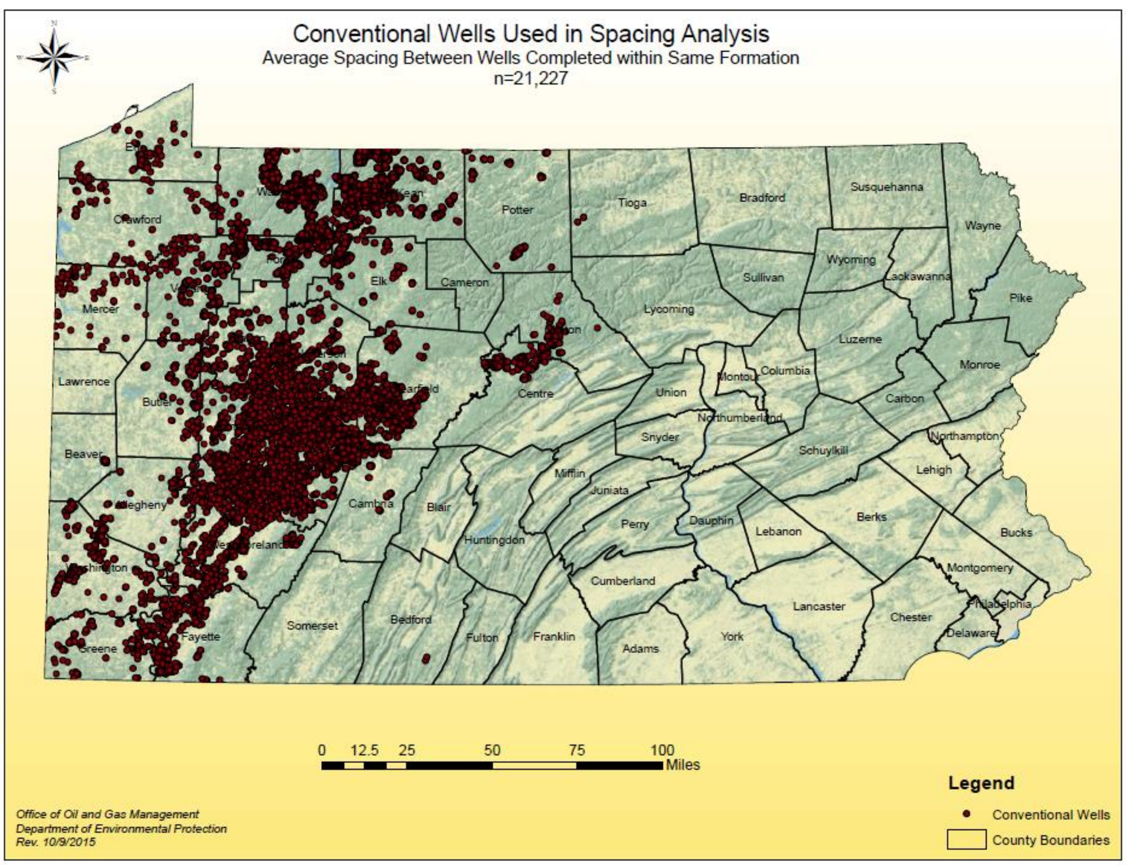

Average Well Spacing (ft) by Formation, nearest well, dups removed
1600
1400
1200
1000
800
600
400
200
0
794
619
1061
927
655
536
833
971
1073
1147
1387
855
934
480
677
1302
1288
1257
299
478
ALLEGHENY, n=13
BRADFORD, n=12,630
BRALLIER, n=676
BURGOON SANDSTONE, n=9
CATSKILL, n=13
CHADAKOIN, n=58
CONEMAUGH, n=2
ELK, n=5,164
HELDERBERG, n=13
LOCK HAVEN, n=454
MAUCH CHUNK, n=2
MEDINA, n=2
MURRYSVILLE SANDSTONE, n=26
OHIO SHALE, n=6
ORISKANY SANDSTONE, n=2
POTTSVILLE, n=14
QUEENSTON, n=343
RIDGELEY, n=2
SHENANGO, n=3
VENANGO, n=1,775


Well Spacing (ft) by Formation (nearest well)
1600
1400
1200
1000
800
600
400
200
0
ALLEGHENY, n=13
BRADFORD, n=12,630
BRALLIER, n=676
BURGOON SANDSTONE, n=9
CATSKILL, n=13
CHADAKOIN, n=58
CONEMAUGH, n=2
ELK, n=5,164
HELDERBERG, n=13
LOCK HAVEN, n=454
Min Outlier
Max Outlier

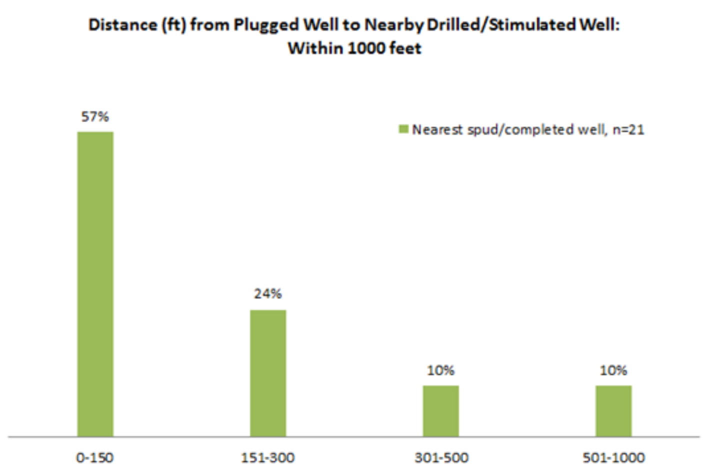


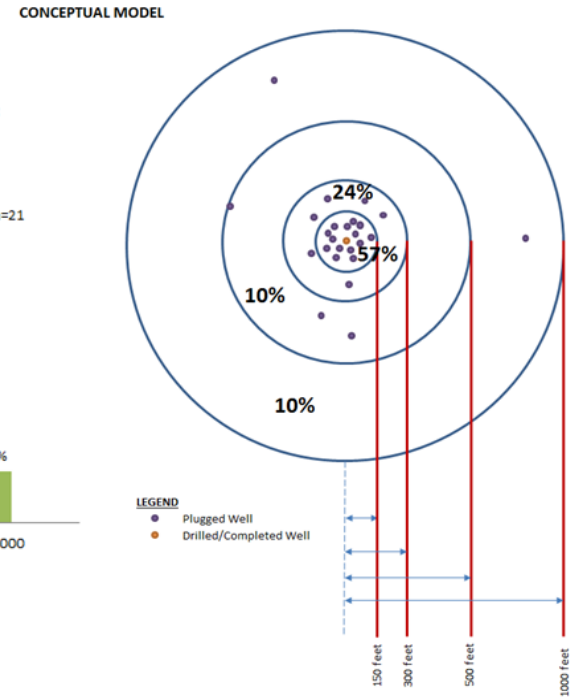
(Source: DCNR EDWIN and DEP eFACTs, 2015)

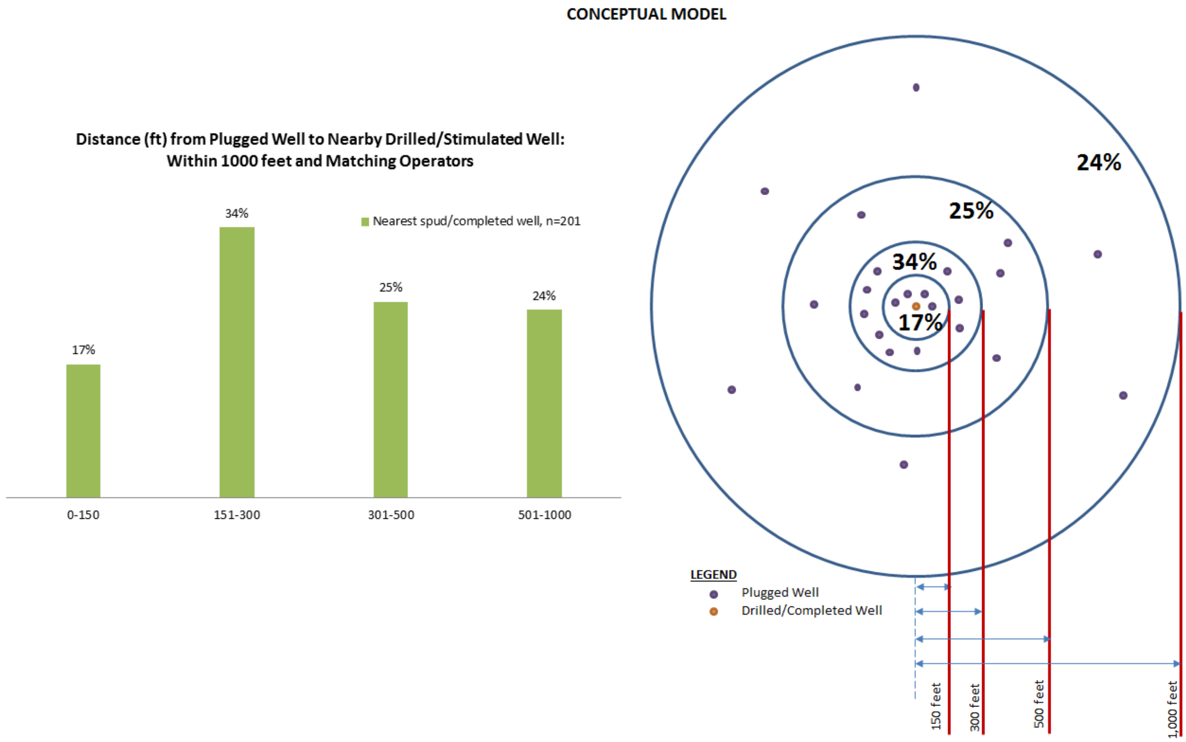
The preceding three figures illustrate that the chosen area of review distances for conventional wells are appropriate: 1,000 feet from the vertical wellbore for gas wells and 500 feet from the vertical wellbore for vertical oil wells. In the first of the three figures above, two well-known oil producing formations are highlighted in red. The wells considered in the well spacing analysis are mapped below.



The Department also used data available in EDWIN and eFACTS to study industry practices with regard to drilling, stimulation and plugging. It is expected that well plugging that takes place around the time of drilling or stimulation may be executed either to preemptively reduce the potential for communication, address a communication incident that occurs as a result of well stimulation activities or because of diminished production in nearby wells, i.e., adjacent wells may be “flooded out.” To evaluate this further, the Department assessed two datasets: one in which plugging took place at nearby wells within a year of stimulation or drilling and the plugging was completed by an “unknown” operator (n=21); and the second in which plugging took place at nearby wells within a year of stimulation or drilling and the plugging was completed by the same operator that drilled/fractured the nearby well (n=201). Frequency distribution diagrams and conceptual models for each dataset are included below.

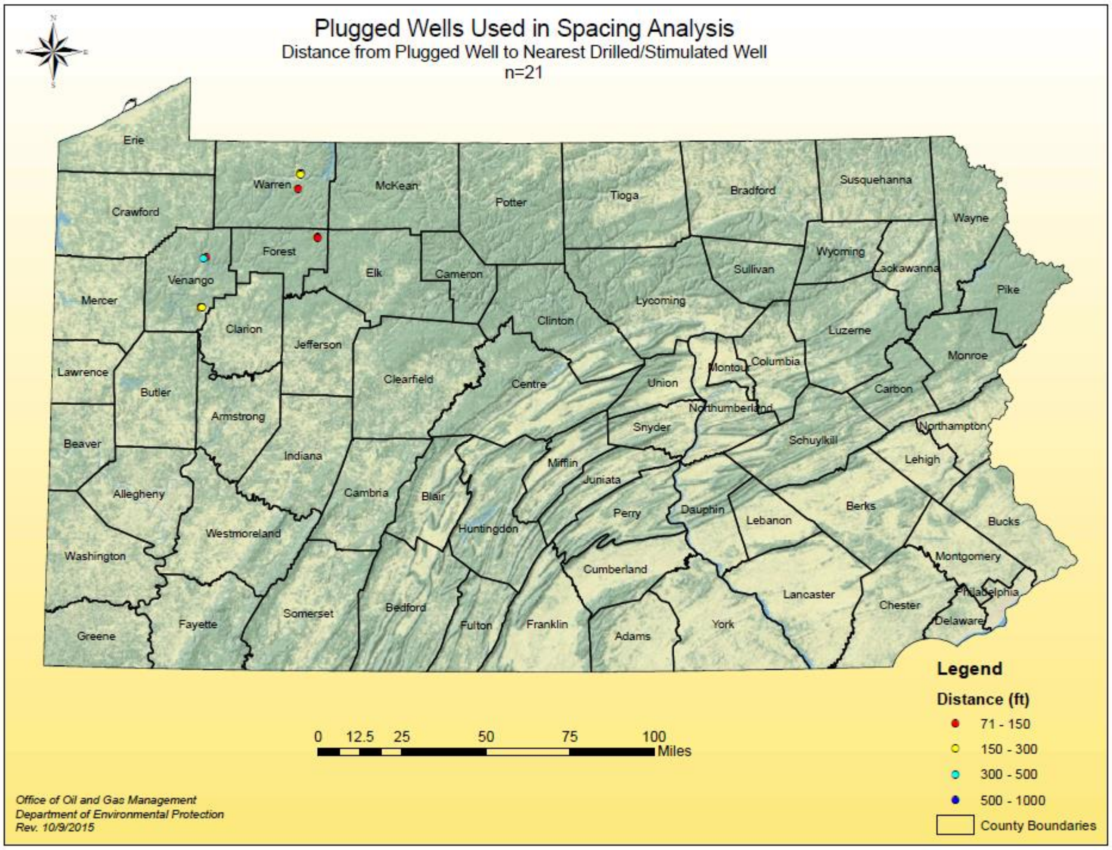


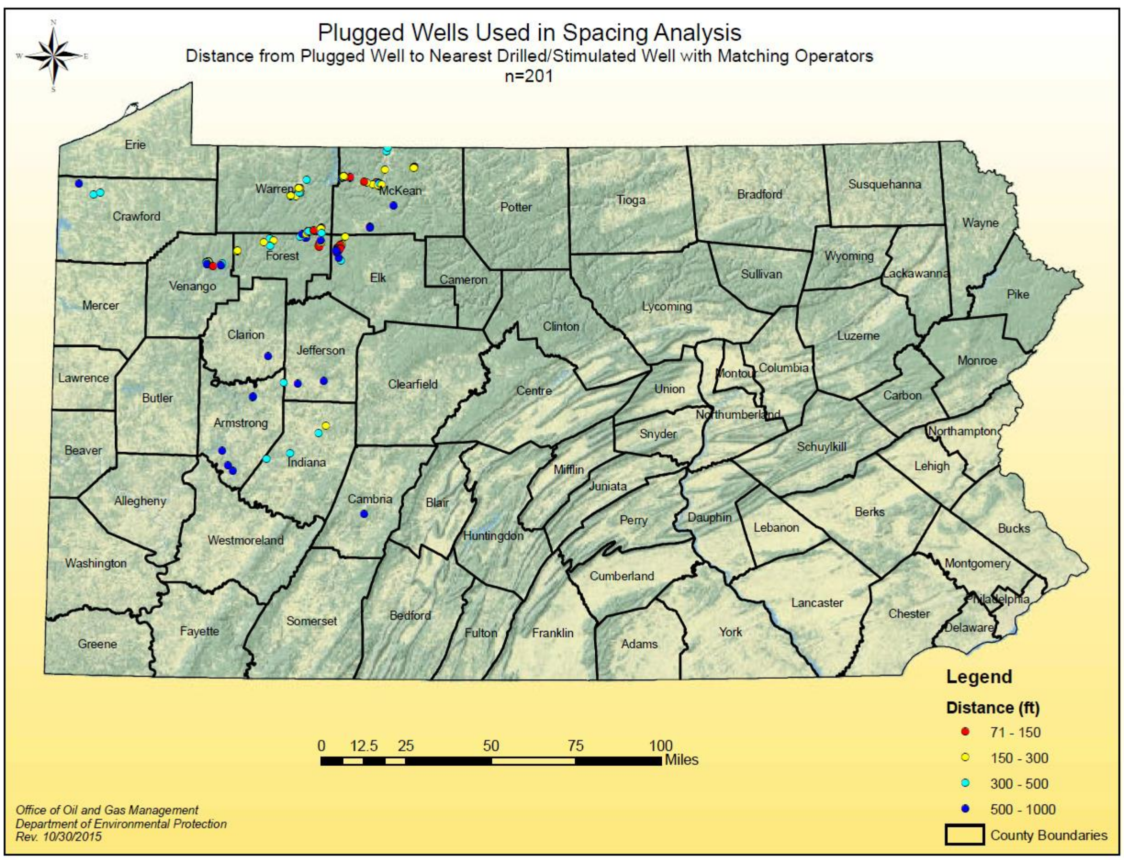




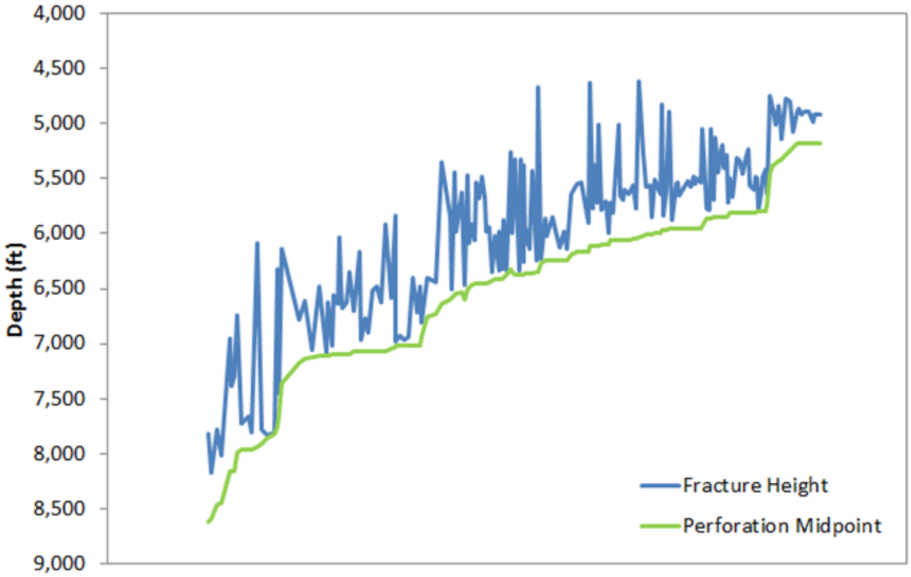
(Source: DCNR PA*IRIS/WIS and DEP eFACTs, 2015)

Although the exact reasons for plugging are not known, the datasets show that it is not unexpected for conventional operators to plug wells at distances between 500 and 1,000 feet from a recently drilled and stimulated well (between 10% and 24% of the wells plugged were found within this distance category). The wells considered in the two analyses are mapped in the figures that follow. Only those wells that exclusively fall within "shallow" (Upper Devonian or younger) or "deep" reservoir areas (Middle Devonian or older) were retained for this analysis.

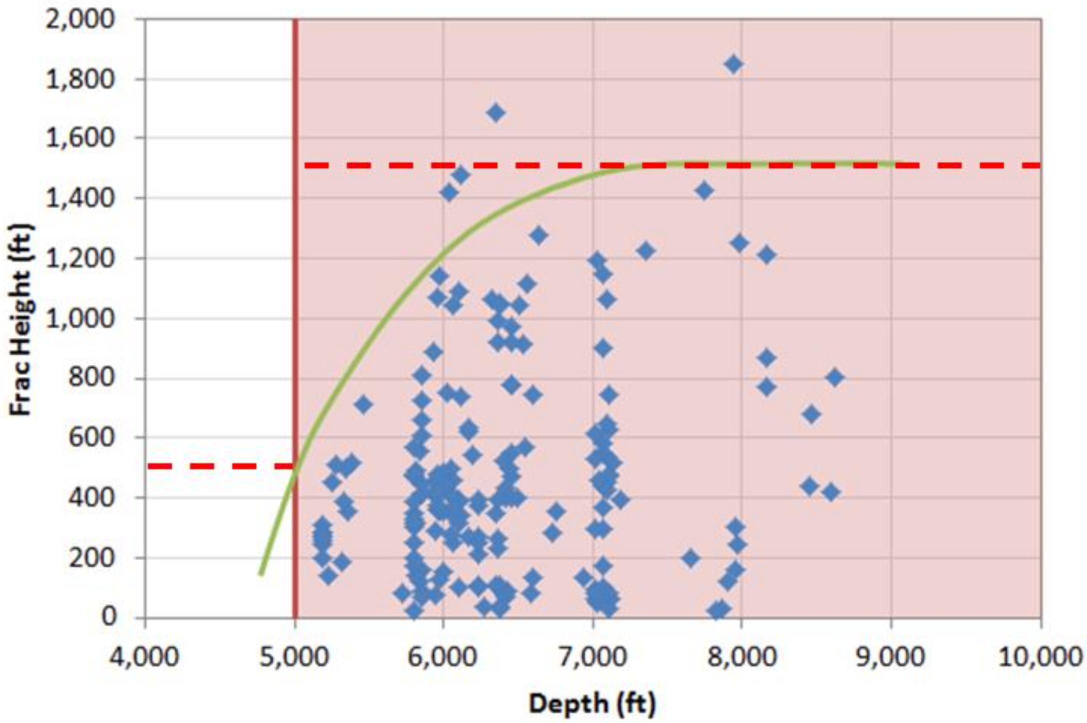

Plugged Wells Used in Spacing Analysis
Distance from Plugged Well to Nearest Drilled/Stimulated Well
n=21
Erie
Warren
McKean
Potter
Tioga
Bradford
Susquehanna
Wayne
Crawford
Forest
Venango
Elk
Cameron
Sullivan
Wyoming
Lackawanna
Pike
Mercer
Clarion
Jefferson
Clinton
Lycoming
Luzerne
Lawrence
Butler
Clearfield
Centre
Union
Montour
Columbia
Monroe
Carbon
Armstrong
Northumberland
Snyder
Schuylkill
Northampton
Beaver
Indiana
Lehigh
Mifflin
Juniata
Allegheny
Cambria
Blair
Perry
Dauphin
Lebanon
Berks
Bucks
Westmoreland
Huntingdon
Washington
Cumberland
Montgomery
Lancaster
Philadelphia
Chester
Somerset
Bedford
Delaware
Greene
Fayette
Fulton
Franklin
Adams
York
Legend
Distance (ft)
71 - 150
150 - 300
300 - 500
500 - 1000
County Boundaries
0 12.5 25 50 75 100 Miles
Office of Oil and Gas Management
Department of Environmental Protection
Rev. 10/9/2015


Plugged Wells Used in Spacing Analysis
Distance from Plugged Well to Nearest Drilled/Stimulated Well with Matching Operators
n=201
Erie
Warren
McKean
Potter
Tioga
Bradford
Susquehanna
Wayne
Crawford
Forest
Venango
Elk
Cameron
Sullivan
Wyoming
Lackawanna
Pike
Mercer
Clarion
Jefferson
Clinton
Lycoming
Luzerne
Lawrence
Butler
Clearfield
Centre
Union
Montour
Columbia
Monroe
Carbon
Armstrong
Northumberland
Snyder
Schuylkill
Northampton
Beaver
Indiana
Lehigh
Mifflin
Juniata
Allegheny
Cambria
Blair
Perry
Dauphin
Lebanon
Berks
Bucks
Westmoreland
Huntingdon
Washington
Cumberland
Montgomery
Lancaster
Philadelphia
Chester
Somerset
Bedford
Delaware
Greene
Fayette
Fulton
Franklin
Adams
York
Legend
Distance (ft)
71 - 150
150 - 300
300 - 500
500 - 1000
County Boundaries
0 12.5 25 50 75 100 Miles
Office of Oil and Gas Management
Department of Environmental Protection
Rev. 10/30/2015

The Department recognizes that not all wells in the area of review pose the same risk with regard to communication potential. To distinguish between well's requiring monitoring and those simply requring identification, microseismic data in the public domain were once again consulted (Fisher, M.K., American Oil and Gas Reported, "Data Confirm Safety of Well Fracturing," July 2010). Fracture-propagation heights were digitized and assessed as a function of depth of the stimulated formation. Data are presented in the figures that follow.



Summary Statistics (Frac Height)	
Mean	475.8976
Standard Error	25.90835
Median	402.3689
Standard Deviation	354.2914
Sample Variance	125522.4
Kurtosis	1.499891
Skewness	1.239732
Range	1829.394
Minimum	23.56957
Maximum	1852.963
Sum	88992.86
Count	187
Confidence Level(95.0%)	51.112

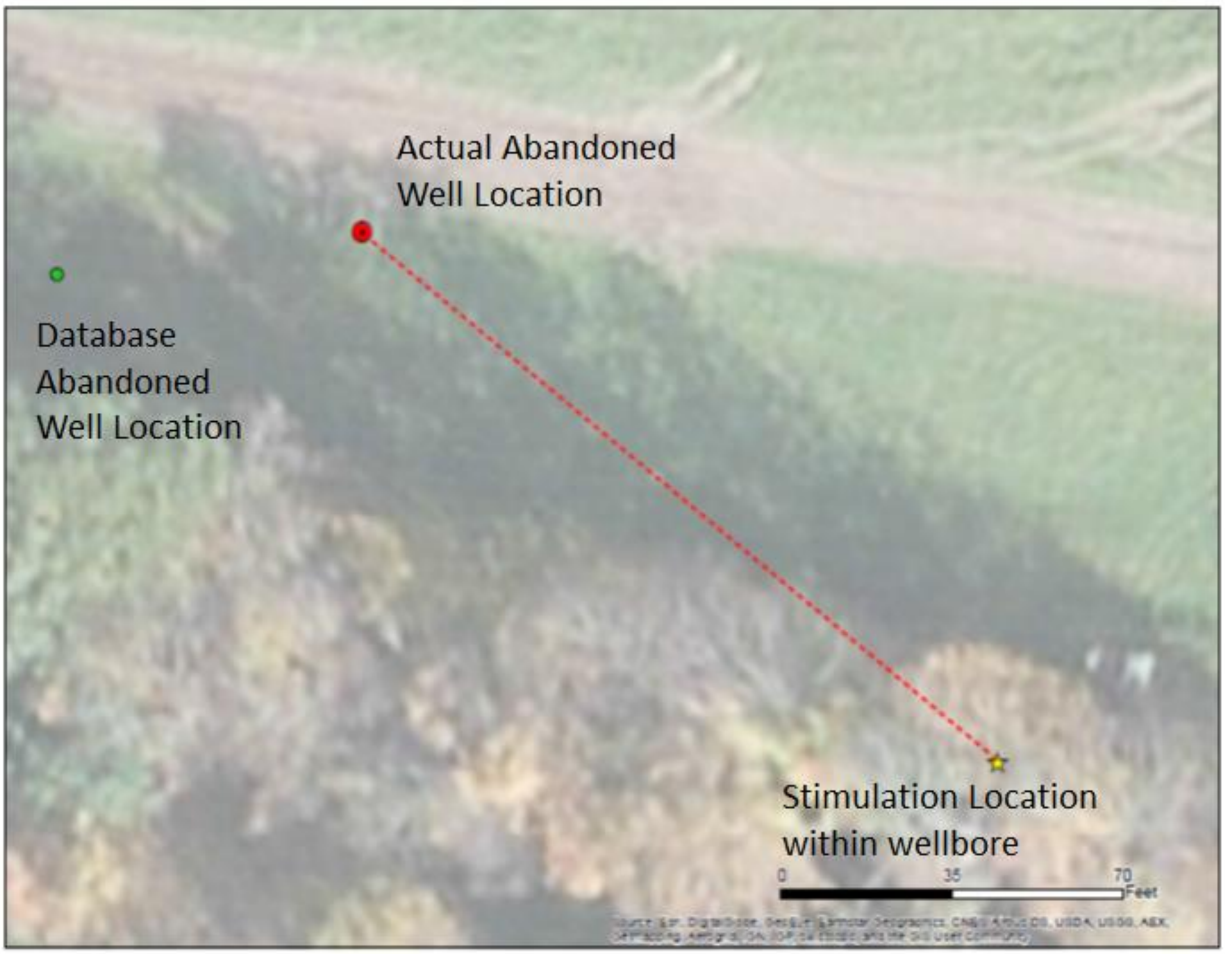


(Source: adapted from Fisher, M.K., American Oil and Gas Reported, "Data Confirm Safety of Well Fracturing," July 2010)

The distribution of data indicate that for shallower wells, it is appropriate to establish a shorter vertical buffer distance with respect to the location of the perforations/notches. The data support the chosen buffer distances of 500 and 1,500 feet for conventional wells less than 5,000 feet deep and greater than 5,000 feet, respectively.

The Department keeps track of communication incidents that are reported to the agency, but until this time there has been no direct regulatory or statutory provision requiring that such incidents be reported. In recent years, a number of incidents have come to the attention of the Department through voluntary reporting or because they led to stray gas migration incidents or other environenmental impacts. The Department has also become aware of other unreported incidents during well assessment activities. Such activities have revealed wells specially plumbed to clean up the excessive amounts of water that “flood out” the produced formation when a frac communication takes place. As part of this rulemaking, the Department studied the geometry of five (5) communication incidents: two (2) at conventional well sites and three (3) at unconventional well sites. The details of these studies are summarized in the series of aerial photographs and tables that follow.

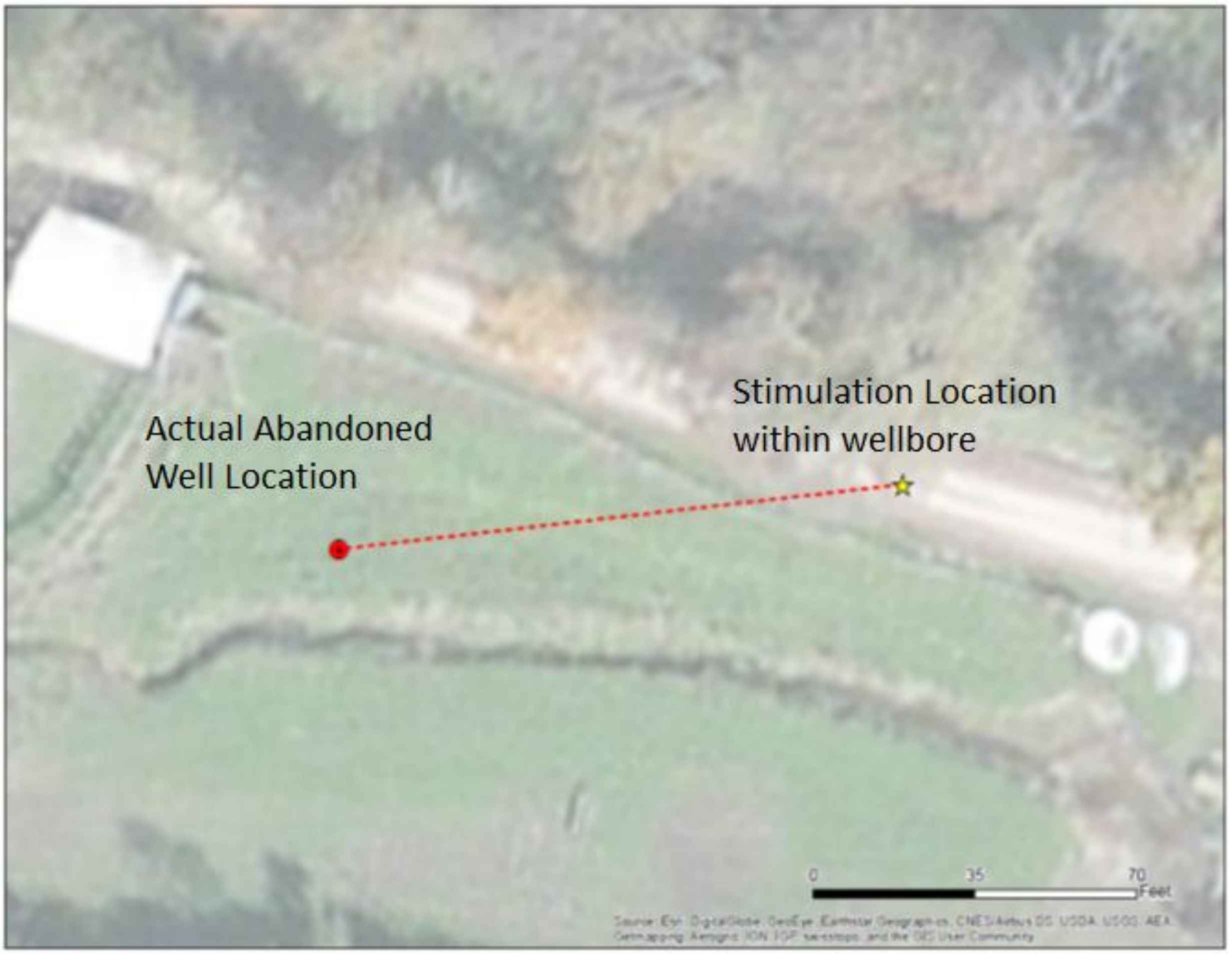
Case Study 1: Conventional Well Site



Well Communicated With:	Abandoned Well
Start Date:	7/14/2014
End Date:	7/14/2014
Environmental incident:	Yes
Communication Type:	Stimulation to Abandoned/Orphan Well
Distance to Communication (ft)	168.7
Azimuth of Communication (degrees)	309
Communication Across Lease Line/Production Unit:	No
Communication Cross-over Any Other Laterals Without Affect:	No

Frac Stage Interval When Communication Observed:	NA
Kick Volume (bbls):	NA
Frac Fluid Volume (bbls):	402 bbls
Max Treatment Pressure (psi):	4800 psi
Average Treatment Pressure (psi):	3146 psi
Abnormal Treatment Volumes Noted:	No
Abnormal Treatment Pressures Noted:	No
Any Faults Present:	No

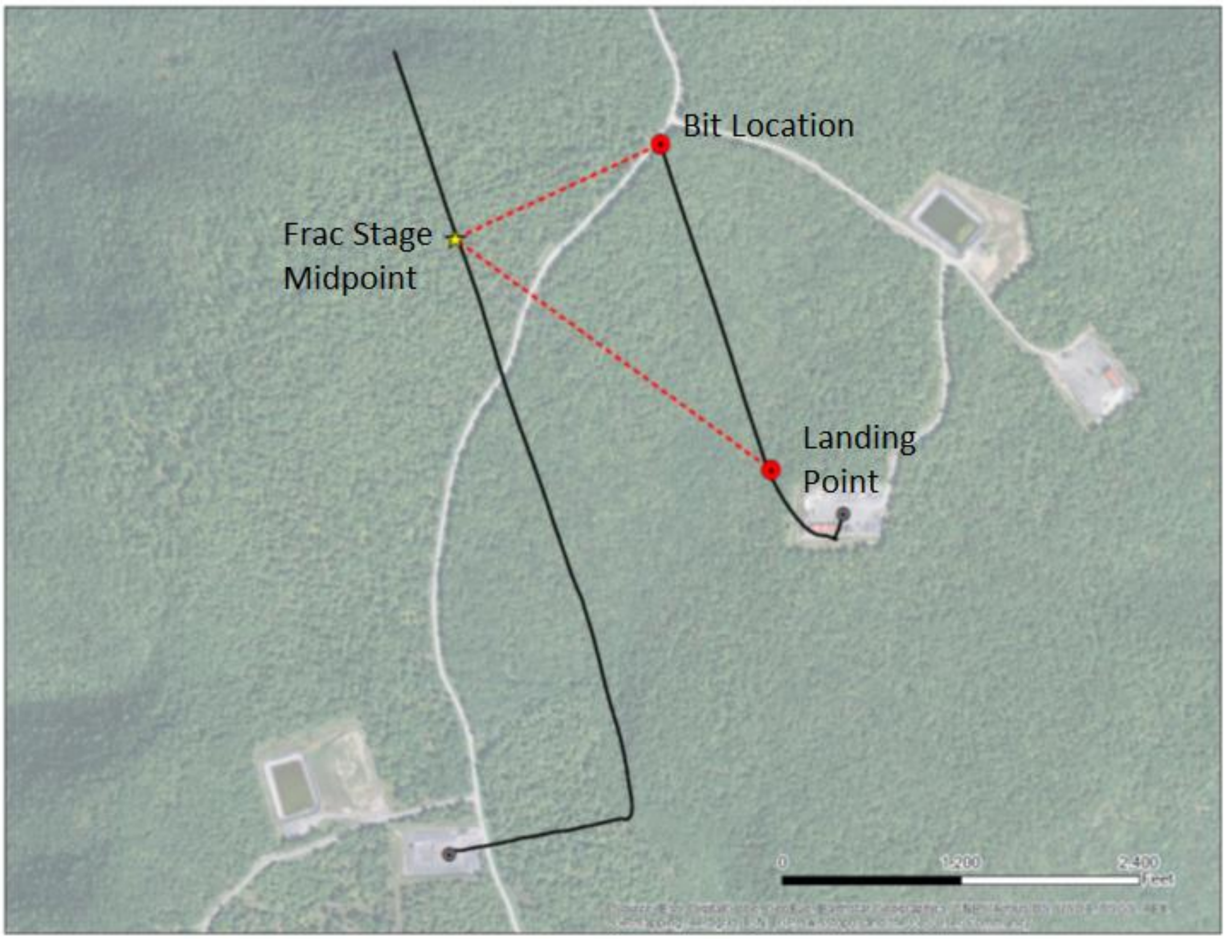
<u>Case Study 2: Conventional Well Site</u>



Well Communicated With:	Abandoned Well
Start Date:	4/7/2014
End Date:	4/7/2014
Environmental incident:	Yes
Communication Type:	Stimulation to Abandoned/Orphan Well
Distance to Communication (ft)	122.8
Azimuth of Communication (degrees)	263
Communication Across Lease Line/Production Unit:	No
Communication Cross-over Any Other Laterals Without Affect:	No

Frac Stage Interval When Communication Observed:	NA
Kick Volume (bbls):	NA
Frac Fluid Volume (bbls):	395 bbls
Max Treatment Pressure (psi):	3450 psi
Average Treatment Pressure (psi):	3250 psi
Abnormal Treatment Volumes Noted:	No
Abnormal Treatment Pressures Noted:	No
Any Faults Present:	No

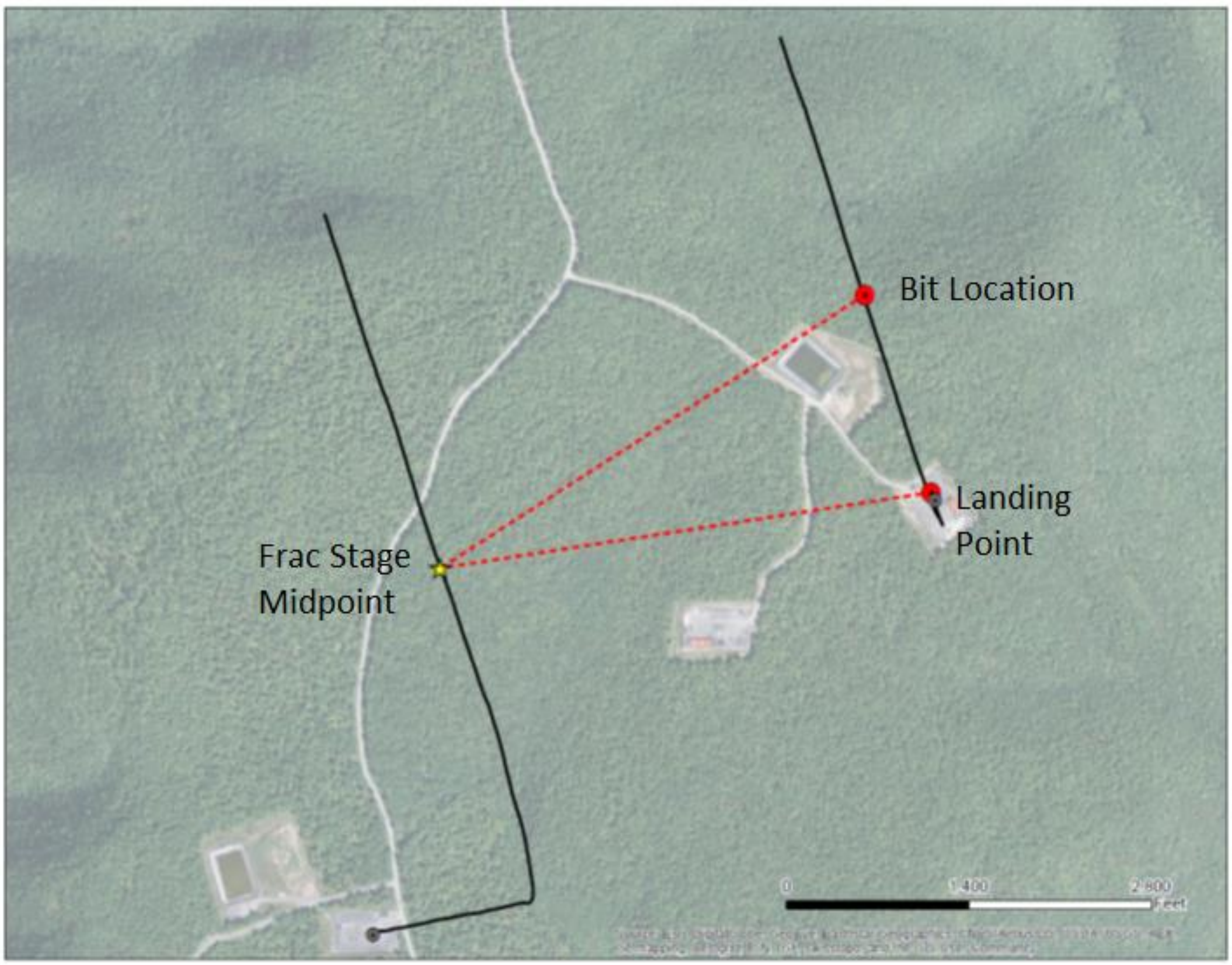
Case Study 3: Unconventional Well Site



Well Communicated With:	Unconventional Lateral
Start Date:	1/13/2013
End Date:	1/15/2013
Environmental incident:	No
Communication Type:	Stimulation to Well Being Drilled
Distance to Communication - Approximate Landing Pt (ft)	2635.1
Azimuth of Communication - Approximate Landing Pt (degrees)	126
Distance to Communication - Bottom Hole (ft)	1523.8
Azimuth of Communication - Bottom Hole (degrees)	65
Communication Across Lease Line/Production Unit:	No
Communication Cross-over Any Other Laterals Without Affect:	Yes

Frac Stage Interval When Communication Observed:	5
Frac Stage Fluid Volume (bbls):	7,965
Max Treatment Pressure (psi):	10,176
Average Treatment Pressure (psi):	9,367
Abnormal Treatment Volumes Noted:	No
Abnormal Treatment Pressures Noted:	No
Any Faults Present:	Yes
If Fault Present, Orientation of Fault in Horizontal Plane:	78

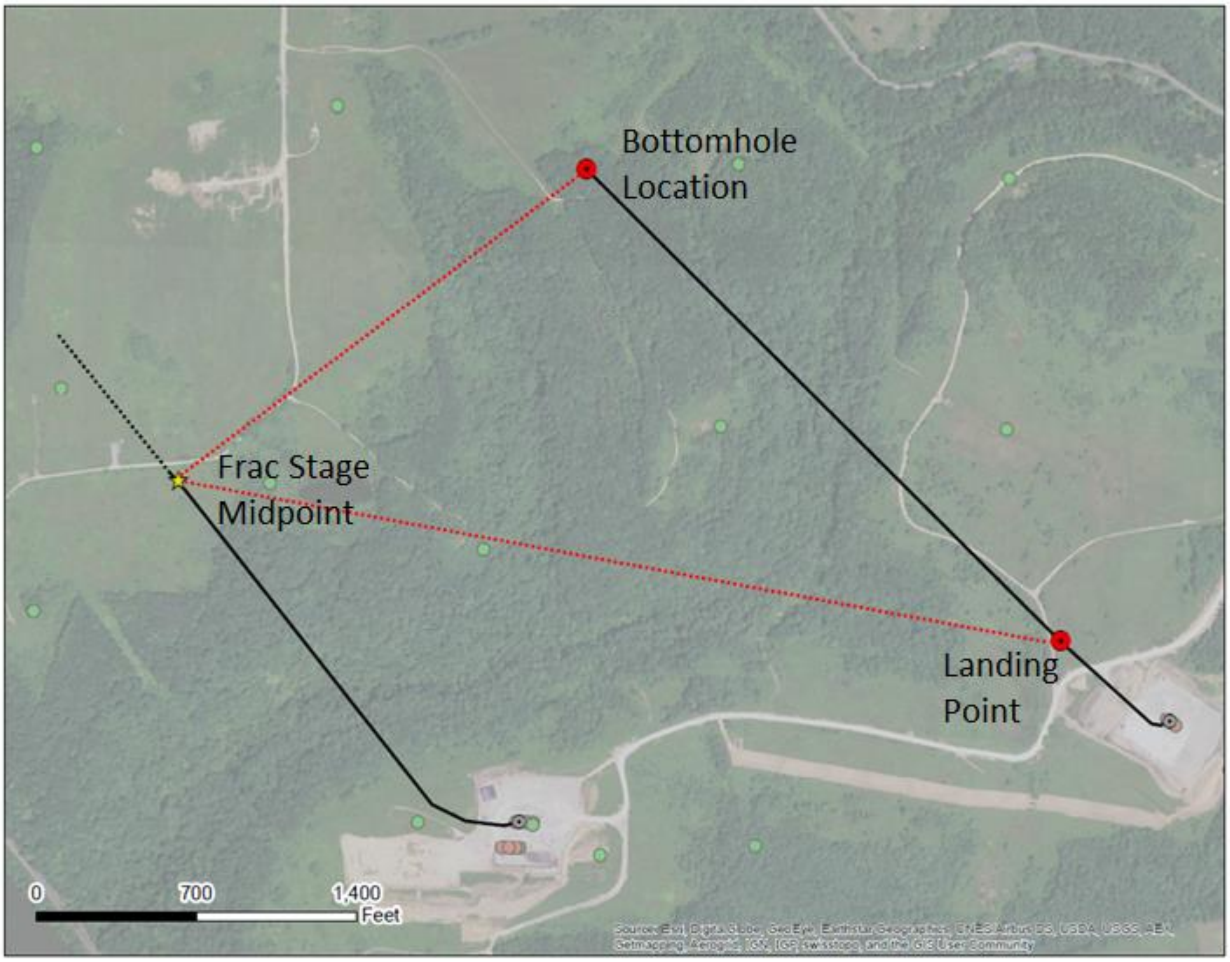
Case Study 4: Unconventional Well Site



Well Communicated With:	Unconventional Lateral
Start Date:	2/1/2013
End Date:	2/3/2013
Environmental incident:	No
Communication Type:	Stimulation to Well Being Drilled
Distance to Communication - Approximate Landing Pt (ft)	3804.5
Azimuth of Communication - Approximate Landing Pt (degrees)	81
Distance to Communication - Well Mid Pt (ft)	3846.5
Azimuth of Communication - Well Mid Pt (degrees)	58
Communication Across Lease Line/Production Unit:	No
Communication Cross-over Any Other Laterals Without Affect:	Yes

Frac Stage Interval When Communication Observed:	10
Frac Stage Fluid Volume (bbls):	8,265
Max Treatment Pressure (psi):	9,496
Average Treatment Pressure (psi):	8,759
Abnormal Treatment Volumes Noted:	No
Abnormal Treatment Pressures Noted:	No
Any Faults Present:	Yes
If Fault Present, Orientation of Fault in Horizontal Plane:	78

Case Study 5: Unconventional Well Site



Well Communicated With:	Unconventional Lateral
Start Date:	8/25/2014
End Date:	9/4/2014
Environmental incident:	Yes
Communication Type:	Stimulation to Other
Distance to Communication - Approximate Landing Pt (ft)	4000.0
Azimuth of Communication - Approximate Landing pt (degrees)	103
Distance to Communication - Approximate Bottom Hole (ft)	2200.0
Azimuth of Communication - Approximate Bottom Hole (degrees)	55
Communication Across Lease Line/Production Unit:	Yes
Communication Cross-over Any Other Laterals Without Affect:	Yes

Frac Stage Interval When Communication Observed	13
Frac Stage Fluid Volume (bbls):	Not available
Max Treatment Pressure (psi):	9816 psi
Average Treatment Pressure (psi):	9092 psi
Abnormal Treatment Volumes Noted:	Yes
Abnormal Treatment Pressures Noted:	No
Any Faults Present:	Yes
If Fault Present, Orientation of Fault in Horizontal Plane:	78

The following table summarizes the communication distances associated with all of the incidents.

Case	Distance (ft)	Information Related to Receiving Well
Conventional Case #1	168.7	Total Distance - Abandoned Vertical Well
Conventional Case #2	122.8	Total Distance - Abandoned Vertical Well
Unconventional Case #1	1,523.8	Minimum Distance (Bit Location)
Unconventional Case #1	2,635.1	Maximum Distance (Landing Point)
Unconventional Case #2	3,804.5	Minimum Distance (Bit Location)
Unconventional Case #2	3,846.5	Maximum Distance (Landing Point)
Unconventional Case #3	2,200.0	Minimum Distance (Bottom Hole Location)
Unconventional Case #3	4,000.0	Maximum Distance (Landing Point)

The incidents studied involved communications with abandoned wells, completed wells and wells in the process of being drilled. As the preceding table illustrates, distances are variable and sometimes had to be estimated based on the length of open wellbore that could potentially serve as the receiving point of the communication. In some cases, failed primary cementing led to the incident. Geologic features may have also played a contributory role in some of the incidents, as mapped faults were occasionally identified locally. In at least one case, pressure treatment volumes were significantly higher in association with the fracture stage when the communcation took place in comparison to adjacent fracture stages.

The Department contends that these case studies support additonal provisions in the regulation: (1) development of a mechanism for reporting and responding to incidents that occur beyond the area of review and (2) regulatory requirements to measure treatment pressures and volumes for evidence of anomalous fracture propagation.

Question 29

(29) Include a schedule for review of the regulation including:

A. The date by which the agency must receive public comments:	1st Quarter 2014
B. The date or dates on which public meetings or hearings will be held:	1st Quarter 2014
C. The expected date of promulgation of the proposed regulation as a final-form regulation:	2nd Quarter 2016
D. The expected effective date of the final-form regulation:	2nd Quarter 2016
E. The date by which compliance with the final-form regulation will be required:	2nd Quarter 2016
F. The date by which required permits, licenses or other approvals must be obtained:	2nd Quarter 2016

Question 30

(30) Describe the plan developed for evaluating the continuing effectiveness of the regulations after its implementation.

This regulation will be reviewed in accordance with the sunset review schedule published by the Department to determine whether the regulation effectively fulfills the goals for which it was intended. DEP will have continued interaction with the Oil and Gas Technical Advisory Board and industry roundtables. As issues arise, DEP will have continuous evaluation.

Appendix A – Table Summarizing Costs and Savings From Final-Form Rulemaking

	Initial		Annual		notes
	Minimum	**Maximum**	**Minimum**	**Maximum**	
Unconventional Operators Costs					
Identification of Public Resources (§78a.15)			$0	$887,964	Unable to estimate cost of mitigation
Protection of water supplies (§78a.51)			$0	$0	Statutory Requirement
Area of Review (§78a.52a and §78a.73(c))			$0	$11,336,000	
Site Specific PPC Plan (§78a.55)			$0	$0	Pre-existing Requirement
Providing copies of the PPC plan to the landowner and PA Fish and Boat Commission (§78a.55(f))			$0	$21,700	
Banning Use of Pits (§ 78.56)			$0	$0	
Fencing Around Unconventional Well Site Pits (§78a.56(a)(5))			$0	$0	Removed From Rule
Determination of Seasonal High Groundwater Table for Pits & labor to inspect and test the integrity of the liner (§78a.56(a)(78a.62)			$0	$0	Removed From Rule
Tank Valves and Access Lids Equipped to prevent unauthorized access by third parties (78a.56(a) (7) and §78a.57(h))			$0	$3,038,000	
Signage for tanks and other approved storage structures (§78a.56(a)(8))			$108,500	$868,000	
Vapor Controls for Condensate Tanks (§78a.56(a)(10))			$0	$2,170,000	
Secondary Containment for all aboveground structures holding brine or other fluids (§78a.57(c))			$2,170,000	$4,340,000	
Identification of existing underground/ partially buried storage tanks and registration of new underground/ partially buried storage tanks (§78a.57(e))	$20,000	$20,000	$0	$0	

Corrosion protection for permanent aboveground and underground tanks (78a.57(f)-(g))			$0	$0	Statutory Requirement
Monthly Maintenance Inspection (§78a.57(i))			$0	$2,700,000	
Radiation protection action plan (§78a.58 (d))	$85,000	$170,000	$489,000	$1,141,000	
Well Development Impoundment Construction Standards (78a.59a, 78a.59b)	$2,253,000	$8,273,000	$2,210,000	$3,070,000	
Centralized Impoundment (§78a.59c)	$39,000,000	$65,000,000	$480,000	$920,000	
Onsite Disposal (§78a.62-63)			$0	$0	
Alternative waste management (§78a.63a)			$0	$0	
Secondary Containment (§78a.64a)			$0	$0	
Site Restoration (§78a.65)			$0	$0	
Reporting and remediation of spills and releases (78a.66)					Unable to estimate
Borrow Pits (78a.67)			$0	$0	
Gathering Lines					Unable to estimate
Corrosion Control for Gathering Lines (§78a.68(g))					Unable to estimate
Horizontal Directional Drilling					Unable to estimate
Well Development Pipelines for Oil and Gas operations (§78a.68b)					Unable to estimate
Prohibition of buried well development pipelines (§78a.68b(b)-(c))					Unable to estimate
Water Management Plans (78a.69)			$0	$0	Statutory Requirement
Monthly Waste Reporting			$438,000	$657,000	
Total New Costs	**$41,358,000**	**$73,463,000**	**$5,895,500**	**$31,149,664**	

	Initial		Annual		notes
	Minimum	**Maximum**	**Minimum**	**Maximum**	
Conventional Operators Costs					
Electronic Filing					Unable to estimate
New notifications to the Department			$0	$0	
Identification of Public Resources (§78.15)			$0	$728,364	
Protection of water supplies (§ 78.51)			$0	$0	Statutory requirement
Area of Review (§78.52a and 78.73(c))			$0	$600,300	
Site Specific Prevention and Contingency Plan (PPC) Plans (78.55)			$0	$0	Existing requirements
Providing copies of the PPC plan to the landowner and PA Fish and Boat Commission (§78.55)			$0	$66,700	
Tank Valves and Access Lids Equipped to prevent unauthorized access by third parties (§78.56(a)(6))			$0	$0	
Minimum 30 mil liner thickness unless thinner material is demonstrated to be equally protective.(78.56(a)(8))			$0	$34,684	Existing requirements
Minimum pit slope of 2:1 or flatter (78.56(a)(9))			$0	$0	
Inspection of pit liner prior to utilizing pit to store waste (§ 78.56(a)(9))			$0	$40,020	
Secondary Containment for all aboveground structures holding brine or other fluids (§78.57c)			$0	$20,877,000	Existing tanks grandfathered until replaced or refurbished
Identification of Underground Storage tanks (§78.57(e))			$0	$20,000	

Corrosion protection for permanent aboveground and underground tanks (78.57(f)-(g))			$0	$0	Statutory requirement
Quarterly Maintenance Inspections 78.57(h)			$0	$5,250,000	annual
Radioactive material action plan (§78.58(d))				$0	
Well Development Impoundment Construction Standards (78.59a, 78.59b)	$0	$634,500	$0	$5,000	first year
Centralized Impoundment Requirements (§78.59c)			$0	$0	
Verifying that the bottom of the pit is 20" above the seasonal high groundwater table (78.62(a)(9))			$7504	$1,000,500	
Alternative Waste Management (§78.63a)			$0	$0	
Site Restoration (78.65)			$0	$0	Existing requirements
Reporting and remediation of spills and releases (78.66)					Unable to estimate
Borrow Pits (78.67)			$0	$0	Statutory requirement
Total Cost	**$0**	**$634,500**	**$7504**	**$28,622,568**	

	Initial		Annual		notes
	Minimum	**Maximum**	**Minimum**	**Maximum**	
Unconventional Operators Savings					
Electronic Submission of well permits (§78a.15(a))			$0	$13,000	
Electronic Submission of water surveys as one package (§78a.52(d))			$0	$21,700	
Two Year Permit Renewal (§78a.17)			$76,440	$91,000	
Well site restoration extension (§78a.65(c)(2))			$0	$0	
Conventional Operators Savings					
Electronic Submission of well permits (§78.15(a))			$0	$10,000	
Electronic Submission of water surveys as one package			$0	$26,680	
Two Year Permit Renewal (§78.17)			$0	$14,720	
Pipeline/Midstream Companies Savings					
Recycling and on-site application of gathering line HDD fluid discharges and returns (§78.68a(k))			$0	$300,000	annual
Total savings for the entire regulated community			**$76,440**	**$477,100**	