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April 5, 2016

David Sumner, Executive Director
Independent Regulatory Review Commission
333 Market Street, 14th Floor
Harrisburg, PA 17120

Re: 25 Pa. Code Chapter 78, Subchapter C, Oil and Gas Wells; Final Form Rulemaking, as Applied to Conventional Oil and Gas Operators (DEP #7-484) IRRC #3042

Dear Mr. Sumner:

The Pennsylvania Grade Crude Oil Coalition ("PGCC") respectfully submits the following comments on the above-referenced final form rulemaking provided by the Environmental Quality Board ("EQB") to the Independent Regulatory Review Commission ("IRRC") on March 3, 2016. PGCC understands that the IRRC plans to vote on this regulatory package at its April 21, 2016 public meeting. Under Section 5.1(j) of the Regulatory Review Act ("RRA"), the IRRC may receive comments from the public up until 48 hours before that vote.

PGCC provided extensive and detailed comments to the Department of Environmental Protection (the "Department" or "DEP") during the public comment periods provided in 2014 with respect to the proposed rule, and in 2015 with respect to the Advance Notice of Final Rulemaking. PGCC also provided detailed concerns about procedural matters to IRRC by letter and in a meeting on October 20, 2015. We incorporate those comments herein and would like to emphasize that most of the central concerns expressed in those prior comments have not been addressed in the final form rule. The comments below specifically address the criteria that IRRC must consider pursuant to Section 5.2 of the RRA as applied to the final form rule, and have been developed with consideration of the final form rule and related documents submitted by the Department to IRRC on March 3, 2016.

We wish to stress that PGCC and its members have not taken and cannot take this rulemaking process lightly. Our industry is under grave threats from both market and regulatory forces, and we appreciate the important role of the IRRC in guarding against regulatory overreach by agencies of the Commonwealth. We believe that this final form rule, which has been tied to and tangled up with rulemaking that is meant to address operations by the unconventional oil and gas

industry, is fatally flawed and contrary to the public interest. We ask that IRRC disapprove the final form rule in its entirety. We appreciate your careful consideration of the attached comments.

Sincerely,

David Clark

cc (w/enc.): The Honorable John Maher
The Honorable Gene Yaw
Secretary John Quigley

Pennsylvania Grade Crude Oil Coalition Comments
on
25 Pa. Code Chapter 78, Subchapter C, Oil and Gas Wells; Final Form Rulemaking, as applied to Conventional Oil and Gas Operators (DEP #7-484) IRRC #3042

I. Deficiencies of the Final Form Rule Under RRA Section 5.2(a)

Section 5.2 of the RRA provides criteria for review of regulations by IRRC. Section 5.2(a) states:

> In determining whether a proposed, final-form, final-omitted or existing regulation is in the public interest, the commission shall, first and foremost, determine whether the agency has the statutory authority to promulgate the regulation and whether the regulation conforms to the intention of the General Assembly in the enactment of the statute upon which the regulation is based. In making its determination, the commission shall consider written comments submitted by the committees and current members of the General Assembly, pertinent opinions of Pennsylvania's courts and formal opinions of the Attorney General.

Section 5.2 b) states that "upon finding that the regulation is consistent with the statutory authority of the agency and with the intention of the General Assembly in the enactment of the statute upon which the regulation is based, the commission shall consider the following in determining whether the regulation is in the public interest: . . . "

PGCC respectfully suggests that a review of the final form Chapter 78 regulation results in a finding that the regulation is neither consistent with the statutory authority nor in conformance with the intention of the General Assembly enacting the relevant statutes. The following provides a non-exclusive list of failings that justify disapproval of the final form rule as applied to conventional operations under Section 5.2(a).

A. Subsections of the Final Form Rule:

78.2 (Scope) The final form rule deletes this section, which currently limits the regulation to the drilling, alteration, operation, and plugging of oil and gas wells. The Department has no authority to strike this section or expand the scope of Chapter 78 beyond the drilling, operation, plugging and alteration of oil and gas wells. Chapter 32 of Act 13, upon which Chapter 78 regulations are based, provides legislative direction related to the permitting, construction, operation, plugging and site restoration for wells and well sites. Offsite facilities, including pipelines, impoundments and borrow pits, are beyond the scope of the legislative authority for this regulation.

78.15(f) (Application requirements), as well as all related definitions in **78.1** ("other critical communities," "playground," "public resource agency," "PNDI Receipt," "wellhead protection area"), which together create a new pre-permit process, is legally invalid for several reasons.

- Statutory authority is lacking because Section 3215(c) of Act 13 was held to be invalid by the Pennsylvania Supreme Court. In Robinson Township v. Commonwealth, the Supreme Court enjoined the application of Sections 3215(c) and (e). After enjoining Sections

3215(b) and (d), Part V of the lead opinion, joined by four Justices stated: "Application of Section 3215(c) and (e) is therefore also enjoined." Robinson Township, 83 A.3d 901, 999, 1009 (Pa. 2013).

- The Department's claims of "other authority" fail because no other authority directs the Department to impose these specific obligations on well permit applicants, and if other general authority directed the Department to consider impacts to public resources and impose well permit conditions, Sections 3215(c) and (e) of the Oil and Gas Act would have been superfluous, unnecessary, and a nullity. One cannot assume that the General Assembly adopts legislation in vain.

- **78.15(f)(1)(iv)** and the new definition of "other critical communities" violate the non-delegation doctrine, allowing unknown persons who populate and manage the PNDI database to impose ever-changing obligations on permit applicants. See "OTHER CRITICAL COMMUNITIES— (i) SPECIES OF SPECIAL CONCERN IDENTIFIED ON A PNDI RECEIPT, INCLUDING THE FOLLOWING: . . ." 78.1 (Definitions)
    - The Department does not manage or populate the PNDI database, but would impose obligations on well permit applicants to review whatever appears on a PNDI receipt, which can change at any time without notice. Applicants would be required to engage in consultation with agencies that do not otherwise have any authority to impose obligations related to "species of special concern," which are not listed species, not threatened or endangered species. DEP is not authorized to delegate the authority to impose obligations related to whatever happens to appear on a PNDI receipt.[1]

- **78.15(f)(1)(iv)** also violates the Commonwealth Documents Law because it would circumvent notice and comment rulemaking by creating a binding norm through an ever-changing PNDI database, a database that is not populated through notice and comment rulemaking procedures.

- **78.15(f)(2)** is contrary to Act 13, which outlines a clearly defined and limited framework for notification obligations and comment opportunities for well permit applications. See revisions in Section 3211(b)(2) (municipalities and storage operators) and new Section 3212.1. Having expressly considered, revised and adopted Act 13 in as recently as 2012, the General Assembly decided exactly how notification obligations and comment opportunities should be expanded for well permitting. The Department has no authority to expand notification obligations or comment opportunities beyond what Act 13 requires, and certainly not to newly defined "public resource agencies," whether local, state and

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[1] Please see the PGCC comments submitted to the EQB on March 14, 2014 ("2014 PGCC Comments"). At page 12 thereof, PGCC cited the Right to Know requests PGCC had submitted to the Pennsylvania Game Commission, the Pennsylvania Fish & Boat Commission and the Department of Conservation and Natural Resources. DCNR is the agency that maintains the Pennsylvania Natural Diversity Inventory (PNDI), which is a database that applicants must consult to determine the presence of any species for which mitigation would be proposed. DCNR responded on January 13, 2014 that it has no records listing or defining Special Concern Species (SCS), and no records describing the criteria or process by which SCS are submitted to the PNDI database. Additionally, DCNR stated that the term "SCS" is a term used by DEP not DCNR.

federal agencies or playground owners, the numbers of which are unknown and unknowable.

78.51(d)(2) (Protection of water supplies) misconstrues Act 13's Section 3218(a) water replacement standard, which allows restored or replaced water supplies to be "adequate for the purposes served."

- Creating an obligation to restore water supplies to Safe Drinking Water Act Standards or better would impose obligations on this industry to fix problems that it did not create, where water supplies did not meet those standards before any drilling occurred, and could very well create an impossible standard if public drinking water supplies themselves could be inadequate or unavailable replacements under this rule.
- This revision is also void for vagueness. DEP admitted at the EQB meeting on February 3, 2016 that this is one of several provisions that it will not implement as written, and which requires technical guidance documents to clarify the new obligations created under this revised section.

78.52a (Area of Review) imposes obligations without statutory authority. DEP does not even try to describe its authority to require well operators to identify active, inactive, orphan, abandoned and plugged wells prior to commencement of drilling. It refers to the State Review of Oil and Natural Gas Environmental Regulations Report for Pennsylvania ("STRONGER"), which found the Department's program to meet or exceed relevant standards in 2013. STRONGER 2013 Review, p. 42, available at http://www.strongerinc.org/state-reviews/ ("The review team finds that the Pennsylvania Abandoned Site Program meets or exceeds the STRONGER Guidelines"). STRONGER, even if it recommended changes in DEP's program, is not a source of regulatory authority.

- This subsection is also void for vagueness because DEP acknowledged at public meetings with TAB, COGAC, and EQB that it will not implement it as written, and that it requires extensive and detailed technical guidance documents to clarify the obligations created under this new subsection.[2]

78.58(f) (onsite processing) improperly removes and restricts the express legislative exemption created in Section 3271.1 of Act 13 related to permitting and bonding requirements of the Solid Waste Management Act ("SWMA"). Contrary to the exemption, the rule would require compliance with the SWMA for processing drill cuttings and residual wastes on well sites.

78.65(d) (site restoration) imposes obligations on small sites under 5 acres that conflict with existing regulations and approvals developed under Pennsylvania Clean Streams Law. Under 25 Pa. Code 102.8(n), wells permitted under Chapter 78 need not comply with expensive and intrusive post-construction stormwater management calculations required under 25 Pa. Code 102.8(g). The revisions in Chapter 78 conflict with the existing provisions in Chapter 10, and

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[2] That vague nature was discussed by members of the Department at the public meeting of the Conventional Oil and Gas Advisory Committee held October 29, 2015 and is available for listening at this site: http://www.dep.pa.gov/Business/Energy/OilandGasPrograms/OilandGasMgmt/OilGasConventional/Pages/default.aspx#.VomcFkQo6po. In their comment letter to the IRRC dated February 2, 2016, members of the Pennsylvania Senate Environmental Resource & Energy Committee detailed certain of those vague matters and expressed their concern that the regulation does not comport with law.

would impose costs and environmental impacts far beyond any benefit. See the additional discussion on this section and related attachments below.

78.66 (spill reporting and remediation) improperly requires small (over 42 gallons, or 43 gallons or more) spills of brine, a relatively harmless substance beneficially used on roads throughout the Commonwealth in much greater quantities both for dust control and de-icing, to be remediated under the Act 2 process, a process that is voluntary for all other industries. The final form rule also adds conditions for reports and submissions to DEP on a timeline that is not imposed on any other industry or entity in Pennsylvania. The costs of such a process far exceed any benefit and improperly impose burdens on small businesses without consideration for alternatives.

78.67 (borrow pits) is contrary to Act 13 and impermissibly limits the scope of Section 3273.1(b), which provides an express exemption from obligations under the Noncoal Surface Mining Conservation and Reclamation Act ("NSMCRA"), or any regulations under NSMCRA, for borrow areas used solely for oil and gas well development. This section would require compliance with 25 Pa. Code Chapter 77 for such borrow areas, against express legislative requirements.

B. Overarching legal flaws

DEP failed to comply with Act 13, Section 3226, which required the Oil and Gas Technical Advisory Board ("TAB") to be consulted in formulation, drafting and presentation stages of the regulation. DEP misstated in the 2013 Regulatory Analysis Form (hereinafter "2013 RAF") and misstates in the 2016 Regulatory Analysis Form (hereinafter "RAF") that TAB unanimously voted to recommend the submission of the revisions to EQB. TAB retracted that vote in May 2013 and informed DEP that the rule was not yet a "proposed rule," as that term is defined under the RRA, because significant portions had been pulled from discussions with TAB and the public. See the attached letters of May 6, 2013 and July 18, 2013, included as Attachment 1. DEP therefore submitted what it called a "proposed rule" to EQB without consulting with TAB regarding what it now calls the four pillars of the rule – public resource protections (78.15), the water replacement standard (78.51), the Area of Review provisions (78.52a), and waste management on well sites (78.58). Each of these provisions is seriously flawed, both as a matter of law and practicality.

Section 1920-A(b) of the Administrative Code of 1929 was violated because EQB failed its statutory duty to "formulate" the final rule and violated the non-delegation doctrine by allowing DEP to develop a lengthy and burdensome rulemaking without input or direction from EQB in the formulation of the rules. DEP has no statutory authority to formulate, adopt or promulgate rules, and EQB's rubber stamp of rules entirely developed by DEP violates the public trust.

The Regulatory Review Act was ignored and violated in both versions of DEP's RAF:

- Section 5(a)(5) - **DEP provided no forms** with the proposed or final rule packages, which is unlawful and improper under the RRA. This is a clear statutory requirement without exception. Submission of forms to IRRC with the final form rule did not and

cannot cure this failing because it is contrary to both the language and purpose of the requirement. Without forms, the public could not fully comment or comprehend the significance or cost of the proposed rule and now has no opportunity to revise its comments or interact with the Department to accomplish the goals or objectives of the revisions. In addition, the forms submitted to IRRC with the final form rule do not match the list provided in the RAF on pages 134-135. It appears that at least twelve forms listed in the RAF were not provided to IRRC with the final form rule.

- Section 5(a)(4) - DEP's revised **cost analysis** improperly attributes zero to many sections of the rule, e.g. 78.51, 78, 78.55, 78.57 f)-(g), 78.65 and 78.67, based on the assertion that the requirements are either already existing or are statutory requirements. PGCC disagrees with these assertions for each section, as explained further below. In addition, a cursory review of the newly provided forms indicates that some may impose costs that have not been reviewed or considered by the Department, such as the new requirement to keep new tank inspection forms on site for one year. Keeping documents on site requires the purchase and maintenance of storage devices that are not currently on those sites.
- Section 5(a)(10.1 thru 12.1) - DEP conducted none of the required **small business analysis**, but simply contrasted conventional from unconventional *operational* differences that have nothing to do with the size of the company. There is not one alternative accommodation or exemption for small businesses in the entire rule.

Under Section 5.2(a) of the RRA quoted above, IRRC is to consider the intent and comments of the General Assembly in its review. An objective review of recent bills adopted by both houses of the General Assembly requires the conclusion that the revisions to 25 Pa. Code Chapter 78 as applied to conventional operations should be barred entirely, leaving the existing rule in place.

Act 126 of 2014 required separation and new *proposed* rulemaking, if necessary, for the two industry sectors. Section 1741.1-E of the **Fiscal Code of July 10, 2014** ("Act 126"). An even clearer statement of this legislative intent was provided in SB 655 of 2015, which the governor vetoed. See Attachment 2. DEP failed to comply with Act 126 when it continued the rulemaking process without providing a new proposed rule, along with all rulemaking requirements of the Regulatory Review Act and the Commonwealth Documents Law. Among the many consequences of this failure to promulgate the rules separately, PGCC and its members have been denied a separate regulatory analysis from the Department, separate consideration and adoption by EQB, and the opportunity for a separate hearing before IRRC on the final form rule. As such, the interests of conventional operators have been severely diluted and muted as the Department marches forward to finalize a rule for the unconventional oil and gas industry.

II. Deficiencies of the Final Form Rule Under RRA Section 5.2(b)

If IRRC proceeds from its legal review to consider whether the various subsections are in the public interest, PGCC respectfully suggests that the rule must also fail because it imposes excessive and unwarranted economic and fiscal impacts on the conventional oil and gas industry, lacks clarity, feasibility and reasonableness, is unsupported by acceptable data as that term is defined in the RRA, and fails to provide less costly or less intrusive alternative methods to achieve the goals of the regulation. Representative subsections of the final form rule are discussed in detail below to further explain these failings. Time prohibits an exhaustive review of each subsection of the final rule.

A central and recurrent failing of the RAF and preamble is the generic and self-serving nature of how DEP has described the "purposes" of the various revisions. While providing clarity is a good and worthy goal, the examples of "clarification" provided by DEP are often euphemism and myth. None of the revisions in the final rule provides clarity that is lacking in the existing rule. See, for example, the Preamble at page 10, claiming that the revisions to Section 78.55 add clarity to existing requirements. As discussed below, the revision created uncertainty and ambiguity that had not existed under the current rule. Indeed, DEP misuses the word "clarifies" on pages 14-16 of the Preamble, where it states that Section 78.65 clarifies well site restoration requirements and that Section 78.66 clarifies remediation obligations. These sections in fact dramatically alter existing restoration and remediation obligations, as explained further below. DEP's regular use of the word "clarity," likely used so often because IRRC's review includes consideration of the clarity of the rule, does not alter the facts that the revisions have created tremendous confusion and uncertainty, and that many key provisions require detailed technical guidance documents for implementation.

Similarly, when DEP provides the sweeping and general purpose of protecting "public health, safety and the environment," it does not in any way justify revision to existing rules.[3] See the Preamble at page 53, discussing the purpose of Section 78.56 revisions, for example. Each specific revision must be justified by a specific purpose or need to show why or how the current regulation has failed to accomplish that purpose. The RAF and Preamble are entirely lacking in such specification of purpose or need for revisions to existing law.

Yet another key failing of the final rule is the DEP's hollow effort to address IRRC's concern with striking the "appropriate balance of protecting the health, safety, environment and property of Pennsylvania citizens while allowing for the optimal development of the oil and gas industry in Pennsylvania "(p. 2). Section 3202 of Act 13 declares its purpose to permit "optimal development of oil and gas resources . . . consistent with protection of the health, safety, environment and property of Pennsylvania citizens." Section 3215(e), even though invalidated under Robinson Twp., required EQB to develop criteria to balance impacts to public resources against the optimal development of oil and gas resources and the property rights of oil and gas owners. These priorities and criteria are entirely lacking from the final rule, which is skewed heavily toward excessive regulation, in the absence of data to explain the need for the revisions or accurate cost analysis to explain or understand the impact on the industry, and fails to provide any alternatives for small businesses. Please note that:

- The RAF does not include the word "optimal" and does not address how the revisions optimize the development of the resources.

[3] In its comments of April 14, 2014 ("IRRC Comments"), the IRRC addressed the failure of the 2013 RAF to state the need for change to the regulations governing conventional oil and gas operations. Among other things, the IRRC said: "While we understand that EQB has the authority to amend its regulations relating to conventional wells, we ask for a detailed explanation of why more stringent regulations for the conventional oil and gas industry are needed at this time." Following those IRRC comments, PGCC explored the need for change via attempted dialogue with the Department and via Right-to-Know requests. PGCC was frustrated in these efforts by the Department's refusal to meet and "no records" response to 128 Right-to-Know requests. A detailed record of this exploration of need is set forth in the PGCC memo to the IRRC dated October 12, 2015; the relevant section begins at page 6 thereof. An example of one of the DEP's responses to the 128 Right-to-Know requests is attached as Attachment 19.

- On page 84 of the preamble regarding public resources, DEP provides the conclusory statement that the final rule's "process for identifying and considering the impacts to public resources will ensure that any probable harmful impacts to public resources will be avoided or mitigated while providing for the optimal development of oil and gas resources."
- In response to Comment 430, the Department declined to define "optimal development of the resources," offers to develop future guidance documents as needed, but reassures the commentator that "[t]here are additional revisions to this section of the rulemaking to ensure that the Department meets its statutory and constitutional *obligations related to protection of public natural resources*" (emphasis added). There is no mention of revisions to promote optimal development of oil and gas resources and protection of oil and gas property rights because there are none.

In spite of repeated requests from IRRC and industry for EQB to explain how the new requirements of the rule "reasonably and adequately balance" protection of the environment against the fiscal impacts on the industry, both explanation and balance are notably absent from the final rule and related documents.

Finally, this entire revision of existing regulations for conventional oil and gas operations is a set of policy decisions of such a substantial nature that it requires legislative review. The final rule should not be promulgated when it is clearly contrary to express legislative direction provided in two recent bills passed by both the Pennsylvania House of Representatives and Senate. See Attachment 2.

Specific sections are discussed in more detail below.

A. Section 78.15(f) – Application Requirements

Under the final rule, Section 78.15(f) requires applicants of a well permit to both notify "public resource agencies" and include in their application an identification and description of the public resource, as well as avoidance or mitigation measures to be taken with respect to such resources. These requirements apply when the well site's "limit of disturbance" falls within, among other things, a location that will "impact other critical communities."

In addition to the reasons provided above in Section I that EQB lacks the statutory authority to promulgate these sections of final rule, Section 78.15(f) of the rulemaking is contrary to the public interest under Section 5.2(b) for the additional reasons described below.

1. *Section 78.15(f) will cause conventional operators to incur significant costs that were not considered by DEP and EQB.*

In its comments to the proposed rule, IRRC requested that EQB clarify "the costs associated with complying with" Section 78.15(f)(1)(iv).[4] In the 2013 RAF, DEP initially stated that there would be no cost to operators in complying with this subsection.[5] In the 2016 RAF, DEP estimated that

[4] Comments of the Independent Regulatory Review Commission, Environmental Quality Board Regulation #7-484 (IRRC #3042), Environmental Protection Performance Standards at Oil and Gas Well Sites, April 14, 2014 (hereinafter "IRRC Comments") at p. 7.
[5] 2013 RAF at p. 17.

the total cost of the provision to conventional operators, not including consultation and mitigation costs, would be approximately $728,000.[6] This number both understates the actual costs to operators associated with identification of resources that would trigger 78.15(f), but also, by the RAF's own admission, fails to take into account the complete array of total costs to the industry, which is required to be considered for purposes of determining whether the final rule is in the public interest.

The RAF expressly declines to provide any estimate of costs associated with consultation with public resource agencies, apparently based on its estimate that only some 30% of well sites would trigger this requirement.[7] In addition to the fact that the Department's conservative estimate of the number of affected well sites is still a significant number, the Department must factor such costs into the total regulatory costs to industry within its RAF.

Moreover, the RAF did not provide any estimate of costs associated with mitigation measures, on the basis that such costs would likely be variable between well sites.[8] While this is true, the Department should have selected a few representative sites for purposes of cost estimation, rather than decline to consider or include such costs from the RAF altogether.

PGCC submitted cost data specifically mindful of mitigation and potential consultation costs in its prior comments.[9] These estimated annual costs totaled nearly $23 million for all conventional well sites, more than 30 times greater than the DEP's estimate. These substantial expenses to be borne by conventional operators are not accompanied by any comparable benefit or need, as further discussed below.

Moreover, the discrepancy between the PGCC and DEP cost data is exacerbated because the DEP failed to perform the work required of it under the RRA. The DEP stated in the RAF that it "reached out to well operators, subcontractors, and industry groups to derive the cost estimates of this final-form rulemaking."[10] Via Right to Know submission, PGCC requested all records prepared, gathered or created in association with all such "reaching out" activities used to "derive the cost estimates of this final-form rulemaking" including, but not limited to, any notice, agenda, or minutes of any meeting, any records of actual costs examined by the Department, and all correspondence between the Department and well operators, subcontractors, and industry groups relating to the reaching out.

The Department responded on March 7, 2016 and provided NO correspondence, agendas, minutes or actual costs. The Department withheld 148 pages of emails and records exchanged between staff with draft outlines of estimates, and five pages of employee notes taken during phone calls with operators. The Department provided a spreadsheet transmitted by email exchange in May 2013 and a 26-page memorandum dated April 25, 2013, from an unnamed person with the subject

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[6] RAF at p. 108.
[7] *Id.* at p. 108.
[8] *Id.* at 108 ("The cost estimate for mitigation will vary…While the Department is unable to provide a specific estimate for implementation of this entire provision, it should be noted that this cost may be substantial depending on the location of the well site").
[9] March 14, 2014 Comments of Pennsylvania Grade Crude Oil Coalition to the Proposed Amendments to 25 Pa. Code Chapter 78 Environmental Protection Performance Standards (hereinafter "2014 PGCC Comments") at p. 33.
[10] RAF at p. 105.

line "Chapter 78 C costs," and containing cost estimates for most proposed regulatory sections (RTK 2013 Cost Memo - see Attachment 21).

As shown by the attached affidavits, the Department never conferred with PGCC concerning its cost estimates and the substantial financial data (derived from actual well costs) submitted by PGCC in March, 2014. Similarly, the Department failed to discuss its cost estimates with the Conventional Oil and Gas Advisory Committee ("COGAC"), despite COGAC's efforts to address the subject. See Attachment 3. The lack of any meeting notice, agenda or minutes, and the lack of any record of any "actual costs" relied upon by the Department speak loudly to the cause of the financial discrepancies. PGCC believes that, as a matter of general compliance with Section 5.2(b) of the RRA, the IRRC should conclude that the void of financial information renders the final rule legally deficient.

As a matter of specific compliance relative to Section 78.15, PGCC notes that the RTK 2013 Cost Memo posits compliance costs much higher than stated by the DEP in the final RAF. For example, for Sections 78.15(d) and (e), the RTK 2013 Cost Memo states the amount of $3,000 per well site but goes on to note that: "If you encounter threatened or endangered species the price goes way up." As to Sections 78.15(f) and (g), the RTK 2013 Cost Memo states the amount of $2,000 per well site but notes the same concern about ambiguity complained about by PGCC (below): "Again, this depends upon <u>what public resources are and what conditions the Department adds to the well permit</u>" (emphasis added). "The initial (sic) administration costs should not be too high, however, complying with permit conditions could easily be in the tens of thousands." Significantly, the "tens of thousands" dollar figure never saw the light of day in either the December 2103 or final 2016 RAF. Instead, the Department's cost estimate is $540 per well (which the Department says includes the cost of protecting threatened and endangered species).[11]

2. *Section 78.15 lacks clarity and is unreasonable and unnecessary.*

IRRC's comments to the proposed rule asked EQB to clarify the definition of "other critical communities," particularly addressing its constituent definition of a "species of special concern," as well as the meaning of the phrase "probable harmful impacts" for purposes of a public resource agency commenting on the adequacy of mitigation measures proposed by the applicant.[12]

Neither the final rule nor its RAF provided such clarification with respect to the type of impacts that would qualify as a "probable harmful" type. The final rule therefore retains the same critical shortcoming of the proposed rule – there is insufficient guidance regarding what mitigation measures would need to be taken, resulting in excessive costs from the exercise of an unnecessary amount of caution due to a fundamentally vague term. Adding an evidentiary requirement for comments from public resource agencies is one example of how the phrase could be clarified. EQB could also have categorized impacts according to their scope or duration, e.g. temporary or permanent, and, following the small business considerations required under the RRA, acknowledged the appropriateness of an alternate method or exemption for conventional operators and conventional well sites that have a small footprint and minimal impacts on public resources. The final rule includes no such effort to do so.

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[11] RAF at p. 107.
[12] IRRC Comments at p. 7.

Moreover, despite IRRC's request that EQB "provide a more detailed explanation of the rationale for [the notification requirement upon determination of impacts to "other critical communities], why it is needed . . . [and] why it is legal,"[13] DEP has not provided a sufficient basis demonstrating a compelling need for Section 78.15(f). In the RAF, DEP stated that the section:

> 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...
>
> To meet these constitutional and statutory obligations, Sections 78.15...establish[es] 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.[14]

As stated above, the Department does not have the statutory authority to regulate public resources through Section 78.15(f) after the decision in Robinson Township v. Commonwealth, due to the Supreme Court's enjoinment of Sections 3215(b) through (e) of Act 13. The Department also improperly continues to rely upon those statutory provisions to require applicants to satisfy PNDI Policy requirements relating to protection of special concern species.[15] Regardless of the authority that may or may not be provided under the various statutes cited, the DEP has failed to identify any "need" let alone a compelling need for additional regulation or entirely new pre-permitting processes to protect any of the listed public resources.

Even if Robinson Twp. did not invalidate Section 3215(e) of Act 13, EQB has failed to follow the express legislative language directing it to develop criteria for the protection of oil and gas property rights and the optimal development of oil and gas resources. Indeed, the statutory purpose of optimizing development of oil and gas is not discussed in the RAF. These failings undermine the entire framework of this new process by which DEP intends to consider impacts to public resources.

3. *The Rulemaking's RAF does not provide acceptable data in support of a purported need for Section 78.15, nor does it consider or provide for more cost-effective alternatives for small businesses.*

Considering that the main basis cited by DEP to justify the rule is to fulfill its generalized "obligation to protect public resources" under the Environmental Rights Amendment and Act 13, it is not surprising that DEP did not provide data to support its statement that Section 78.15 is needed. DEP has not provided, and PGCC is unaware of, acceptable data ("empirical, replicable and testable data as evidenced in supporting documentation, statistics, reports, studies or research," RRA Section 3) to establish that the revisions pursued in the rulemaking are necessary to protect environmental resources or the public health.

Nowhere in the RAF did DEP adduce data establishing that Section 78.15 is necessary to prevent adverse impacts to either resources themselves, or to certain activities, such as tourism or fish and

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[13] *Id.*
[14] RAF at p. 10.
[15] *Id.* at p. 13.

game recreation. To the contrary, as explained in more detail below, a Clarion University study of the Allegheny National Forest ("ANF") showed that despite the existence of nearly 12,000 currently-producing conventional wells within the region, the area contained water resources generally characterized as among the highest water quality in Pennsylvania, and that there had been no apparent impacts to benthic macroinvertebrate communities attributable to oil and gas development.[16] This study shows that conventional oil and gas development need not be subject to more burdensome requirements when the current requirements have been successful at protecting environmental resources.

The lack of a demonstration of need for Section 78.15 is especially troubling in the context of DEP's and EQB's failure to establish a carve-out or any exemption provisions for small businesses, which constitute a significant portion of the universe of conventional operators and all of PGCC members. Here, as elsewhere, the DEP and EQB have failed to meet the requirements of RRA Section 5.2(b)(8). In short, DEP has produced no acceptable data suggesting a compelling need for Section 78.15(f), whereas available data show that no such compelling need exists.

4. *Comments, objections, or recommendations of legislators clearly express concerns that Section 78.15(f) is not in the public interest.*

With respect to Section 78.15, both the Senate and House Environmental Resources & Energy Committees expressed, through incorporation of the COGAC Report, that Section 78.15 would produce several negative consequences and opposed its promulgation:

> The Process outlined by the Department's Final Rule improperly changes established relationships under property and contract law, and would invite unbounded suggestions for the mitigation of perceived impacts from state agencies, local municipalities and schools, in what appears to be a plan to obstruct, rather than foster, the optimal development of the oil and gas resources of this Commonwealth. COGAC members firmly believe that the costs and burdens that would be involved in such a regulatory configuration far exceed the $0 attributed in the RAF. As with the other sections, above, the failure to analyze those costs, state the need, and analyze small business alternatives, makes it impossible to balance whether the proposed regulation complies with the RRA and whether it allows for the 'optimal' development of Pennsylvania's conventional oil and gas resources.[17]

According to these comments, both the House and Senate Committees believe Section 78.15(f) is contrary to both statute and the public interest. For all of the above reasons, IRRC should disapprove the final rule, including the public resource-related requirements of Section 78.15.

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[16] Fritz, K. et al, "*Impacts of Sedimentation from Oil and Gas Development on Stream Macroinvertebrates in Two Adjacent Watersheds in the Allegheny National Forest in Northwestern Pennsylvania*," U.S. Dept. of Energy Office of Scientific and Technical Information (abstract available at http://www.osti.gov/scitech/servlets/purl/1011526).

[17] See February 1, 2016 comments submitted by Environmental Resources & Energy Committee, House of Representatives (hereinafter "House EREC Comments") at p. 15.

B. Section 78.51 – Protection of Water Supplies

Section 78.51 of the final rule subjects operators to the requirement to restore affected water supplies to the standards under the Pennsylvania Safe Drinking Water Act (SDWA), or to the "quality of water that existed prior to pollution if the water quality was better than these standards." This restoration requirement misreads Section 3218(a) of Act 13 and imposes significant costs on conventional operators would impose obligations on operators to solve problems that are not of their making and, in some cases, to achieve what may be impossible to achieve.

1. *The new costs imposed under Section 78.51 are significant and were entirely ignored in the RAF.*

IRRC's comment to the proposed rule requested that EQB "explain how it will enforce [the water supply replacement requirement] to conform to the intent of the General Assembly and Act 13," referencing concerns about the cost of the requirement.[18] In the RAF, DEP stated that there would be no new costs imposed by this provision on account of the rule seeking "to provide clarity to existing statutory requirements."[19]

While Act 13 was adopted in 2012 and does impose certain requirements related to the restoration of water supplies, PGCC disagrees with the Department's interpretation that is created by the language in the final rule. As a result, the true costs to operators resulting from DEP's reinterpretation neither can be said in any sense to be zero, nor can it be attributed as a mere restatement of Act 13. DEP, therefore, failed to properly assess to any degree the true costs of Section 78.51(d) on operators. The true costs of this revision must be understood, especially where remote rural locations cannot be connected to public drinking water supplies and the natural condition of local groundwater does not meet SDWA standards. Shifting such costs to oil and gas operations when Pennsylvania has no standards for drinking water wells is unjustified, contrary to obligations under any other program, and likely contrary to what the legislators intended. Most important, it is inconceivable how "no cost" can be attributed to the interpretation applied by the DEP.

2. *Section 78.51 is unnecessary to protect public health and welfare, is unclear, and is unreasonable.*

The final rule's RAF states that "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."[20] To the extent that the final rule requires conventional operators to restore water supplies to a standard more stringent than the SDWA standards, such a requirement cannot reasonably be said to advance public health. Further, Section 78.51(d) is unnecessary to maintain public health to the extent that it requires improvement of water supplies to a water quality level that did not initially exist.

Finally, Section 78.51(d)(2) is unreasonable to the extent that it may not be technically or practically feasible, considering the wide range of water quality of existing water supplies. To the degree that very high quality water supplies must be restored to the same quality, regardless of the

[18] IRRC Comments, p. 9.
[19] RAF at pp. 108-109.
[20] RAF at p. 17.

fact that there are no obvious resultant public health benefits, this requirement is unreasonable in that it may not be possible to obtain and restore such water supplies within the given time frame under Section 78.51.

3. *Legislative Committee comments reflect their concern that Section 78.51 is not in the public interest.*

Through the COGAC report, both the Senate and House Environmental Resource & Energy Standing Committees have expressed concerns with Section 78.51(d), echoing the comments made above:

> This section would impose an obligation on oil and gas operators that is neither legally required under Act 13 nor practically achievable under certain circumstances…
>
> Additionally, in public presentations the Department has acknowledged that after several years of deliberation the technical feasibility and cost to comply with this provision of the regulation is unknown and will not be known until guidance documents are promulgated. However, this provision is substantially more stringent than comparable provisions in other DEP regulations…
>
> Further, the Department is imposing standards on water supplies that are largely unregulated, have no construction standards and are not subject to State or Federal water quality standards.
>
> The revised language in the Draft Final Rule would impose obligations on oil and gas operators that are neither legally required nor practically feasible.[21]
>
> Section 78.51(d) should be disapproved pursuant to Section 5.2 of the RRA.

C. <u>Section 78.52a - Area of Review Requirements</u>

Section 78.52a under the final rule imposes requirements upon conventional operators to conduct a review for the surface and bottom hole locations of active, inactive, orphan, plugged and abandoned wells within 1,000 feet horizontally from the vertical well bore and from the surface above the length of a horizontal well bore of a horizontal oil well or gas well. The area of review is 500 feet for vertical oil wells. The final rule cursorily specifies the types of sources of information that are to be reviewed, including "historical sources of information," "well databases," and results of questionnaires that operators would be required to gather from surface owners within the applicable distance thresholds. This section, along with 78.73(c) and (d), (collectively, the AOR provisions) also impose monitoring requirements of certain identified wells through the submission and implementation of a monitoring plan, to be approved by DEP.

As noted above, DEP lacks the statutory authority to promulgate the final rule. In addition, Section 78.52a and revisions to 78.73 are contrary to the public interest according a review under Section 5.2(b) of the RRA.

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[21] House EREC Comments at p. 16.

1. *Section 78.52a poses significant costs to conventional operators that have not been fully considered by DEP and are not justified by an attendant need.*

IRRC's comments on the proposed version of the final rule asked EQB to explain "how the benefits outweigh any costs."[22] To answer this inquiry, it is necessary for DEP to properly characterize the costs imposed by the rule, including the AOR provisions. The AOR provisions will impose significant adverse economic impacts on conventional operators, impacts that have not been accurately characterized or calculated by the Department. In the RAF, the Department estimated a cost of $250 per well for professional surveying costs, and $200 to $225 per well for costs of fluids management tank rentals and reporting costs, for a total cost to the industry of approximately $600,000.[23]

These estimates do not capture all costs created under these provisions. The costs depend upon the size of the area to be studied, the type of onsite monitoring required, the extent of research and document review required, and the unknown type and breadth of conditions the Department will impose before it approves the newly required "Monitoring Plan" (and thus allows well completion to go forward). The impermissibly vague nature of these requirements is discussed in more depth below; however, that vague nature prevents PGCC from providing a definitive annual cost. Instead, in the comments PGCC provided to the DEP in May 2015 and to the IRRC on October 12, 2015, PGCC estimated the annual AOR compliance costs in the range of $10 million to $50 million. PGCC's chart of costs reflective of the ANFR AOR revisions is attached. See Attachment 4. PGCC believes this range of estimated costs is far more accurate than the $0 cost attributed by the DEP in the 2013 RAF and the cost of $600,000 provided in the revised RAF.

In an ironic proof of the vague nature of the rule, the DEP is preparing a guidance document, which in its current form is already 62 pages in length. PGCC notes that, at least in its current iteration, the guidance document would reduce some of the $10 to $50 million cost anticipated by PGCC. For example, while the regulation requires an area of review radius of 500 feet for conventional oil operations, the guidance document would, in most relevant ways, reduce that radius to 200 feet. At Attachment 5, PGCC has included its recently compiled estimate of the costs incurred to comply with the survey, research and monitoring portions of the rule as interpreted by the tentative draft of the guidance document. That cost is $2,765 per well, an amount over ten times greater than the Department's estimate in the RAF of $200 to $225 per well for surveying costs.[24] It is impossible to estimate the balance of the costs discussed in the RAF, such as fluids management, tank rentals, and the like, because the nature and extent of these requirements remain unknown to PGCC.

What is certain, however is the impossibility of having an informed discussion of "how the benefits outweigh the costs" inasmuch as the guidance document that would help define the costs is not yet complete and inasmuch as the needs for the requirement remain unarticulated. The

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[22] IRRC Comments at p. 9-10.

[23] RAF at p. 109.

[24] The DEP invited conventional industry members to participate in the drafting of the guidance document; but despite request from those industry members, the DEP did not allow any discussion of the costs of compliance. This was a forfeited opportunity to attempt the goal of "consensus" set forth at Section 2 of the RRA and cited in the IRRC's April 14, 2014 document at page 2.

Department summarily dismissed this discussion by concluding that "costs will be insignificant in comparison to potential liabilities associated with a hydraulic fracturing communication incident."[25]

This dismissal fails to address the extensive comments provided by PGCC on May 19, 2015, including the powerful incentives already at play that motivate an oil and gas operator to act prudently to avoid the risk of a communication event. The fact remains, the bulk of costs related to the AOR provisions are attributable to the requirement in 78.52a to identify abandoned wells within the unreasonable distance thresholds specified in the rule, and requiring paperwork and processes that provide no meaningful benefit. As set forth in more detail below, the geographical areas of concern and the risk of communication incidents are overstated by the Department and do not justify the many paperwork and notice burdens—especially inasmuch as the cost of those burdens remain unknown.

2. *Section 78.52a is not necessary to protect the public health, safety and welfare, or the Commonwealth's natural resources.*

IRRC's comment on the proposed rule inquired as to "how [the subsection] protects public health and the environment."[26] In response, the final rule's RAF states, without data or factual support, that "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."[27] DEP then purports to address this risk by establishing multiple reporting and other "legwork" obligations.

DEP's stated risks are unsupported and contrary to the experience of conventional operations, which indicates an insignificant risk of communication incidents and an insignificant risk of harm to the environment related to those events. The PGCC comments of May 19, 2015 observe that a communication event spells economic destruction to the well being completed (because the effectiveness of the hydrofracture is thwarted by the communication). This is a powerful economic incentive for the well operator to prudently place the well to avoid communication. The DEP never addressed the significance of this key economic incentive nor has the DEP made any showing that the questionnaires to surface owners and the other "legwork" required under the AOR rule will in any way prevent communication incidents or make operators act more prudently.

Indeed, there are some 12,000 currently-producing conventional wells within the Allegheny National Forest ("ANF") that have co-existed among tens of thousands of former wells that were drilled over the past 150+ years.[28] In the current regulatory state, devoid of the new AOR provisions, 72% of the mapped streams in the ANF are rated as high quality or exceptional value for water quality, which is generally characterized as among the highest water quality in

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[25] RAF at p. 110.
[26] IRRC Comments at p. 9.
[27] RAF at p. 19.
[28] See Harris, S.C., "*Impacts of Oil and Gas Development on Aquatic Macroinvertebrates in the Allegheny National Forest*," 2012 Goddard Forum on Oil and Gas Impacts on Forest Ecosystems, Penn State University (available at http://extension.psu.edu/natural-resources/forests/private/training-and-workshops/2012-goddard-forum-oil-and-gas-impacts-on-forest-ecosystems/gas-impacts-on-aquatic-macroinvertebrates-in-the-anf).

Pennsylvania. In addition, a Clarion University study reviewing data gathered from the 1980s to 2010 on benthic macroinvertebrate communities concluded that based on these data, there was no negative impact to water quality in the ANF from oil and gas development during the same time.[29]

Coupled with the lack of data adduced by DEP on the likelihood or nature of communication incidents, the RAF fails to establish that the AOR provisions are necessary to protect the public health or the Commonwealth's natural resources.

3. *Section 78.52a lacks the requisite clarity and reasonability, supporting data and need for promulgation.*

Notwithstanding IRRC's specific comment regarding the lack of clarity of Section 78.52a,[30] the final rule remains unclear regarding requirements imposed on conventional operators under this subsection. In particular, the methods of identification of wells provided in 78.52a(c) lack specificity and direction, and are impermissibly vague as to how individual operators would satisfy their obligations. Under 78.52a(c)(2), operators are required to conduct a "review of historical sources of information, such as applicable farm line maps, where accessible." This provision is unclear as to both (1) the scope of "historical sources" that may go beyond farm line maps, and (2) the precise depth of review and verification that is required of such sources.

Under Section 78.52a(c)(3), operators are required to submit a questionnaire to landowners within the applicable area of review "regarding the precise location of wells on their property." The items to be covered or included in the questionnaire are not specified. As explained below, such forms were only recently provided to TAB, IRRC, legislative committees and the public, despite the RRA's requirement that <u>all</u> forms required for implementation be provided on that <u>same date as submission of the proposed rule</u>. A lack of forms during the review period rendered it impossible for IRRC and other reviewers of the rule to fully understand or evaluate exactly what will be required by Section 78.52a. The final rule fails to clarify the scope of obligations that may remain on an operator in the event that landowners either do not respond, or respond without providing the necessary information required to identify wells within the applicable area of review. Without sufficient specificity, operators may be subject to an unreasonable scope of review requirements.

Other areas in which these subsections lack clarity include: 1) the scope of obligations imposed on operators who locate a well on a historical map but in subsequent investigation, cannot find any further details of the well, 2) when they are required to conduct a surface inspection for the purpose of determining well integrity, without any greater direction as to how to make such a determination, 3) what monitoring will be required as to identified wells (will an active well

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[29] "*Impacts of Sedimentation from Oil and Gas Development on Stream Macroinvertebrates in Two Adjacent Watersheds in the Allegheny National Forest in Northwestern Pennsylvania*," U.S. Dept. of Energy Office of Scientific and Technical Information (abstract available at http://www.osti.gov/scitech/servlets/purl/1011526).

[30] IRRC Comments at p. 10 ("We agree that it is unclear as to how the regulated community is expected to comply with these provisions. Are there expectations for operators beyond submitting questionnaires to landowners and submitting proof of submitting the questionnaires? Will there be a timeframe for compliance? What proof of notification will EQB require from operators? We ask EQB to clarify the implementation procedures related to these subsections").

within the area of review require the same monitoring as an abandoned well; will the monitoring require equipment, full-time personnel at each well, and record keeping?); and 4) what operators are expected to do when access to adjacent properties is denied. Clearly, these provisions involve an infinite array of obligations and create an excessive and unwarranted financial burden to the industry.

The lack of clarity of the final rule is also evident from the disparate interpretations by DEP officials of the impacts of Section 78.52a. Of particular note, one member of DEP informed TAB and COGAC that the DEP's review of monitoring plans required under Section 78.52a would enable it to deny the monitoring plan, enabling it to prohibit completion of a new well, without any clear standard of review. Another DEP official disagreed, stating that the review process for monitoring plans would merely be a "spot check."[31]

Critically, the final rule's RAF fails to provide acceptable data in support of the AOR distances in Section 78.52a. The sole quantitative data specifically associated with conventional operations cited in the RAF includes two data points in a "case study" of communication incidents.[32] This information was provided to the public for the first time in the final rule RAF, entirely frustrating any possibility of public discussion and/or review of the reliability or validity of the study. DEP is apparently ill-equipped to evaluate the risk of communication with the information that it has and would have benefitted greatly from input from industry. This issue is one for which the industry has tremendous practical knowledge and experience that should have been considered and consulted prior to the development of the proposed rule. DEP's 11th hour data entirely fails to support or justify its final form rule.

Both of these communication incidents occurred at distances of 168.7 feet and 122.8 feet – each is less than half the AOR distances in the final rule. The only communication incidents cited by DEP that exceeded the AOR distances were associated with unconventional operations. This data is entirely inadequate to support the 500 foot (conventional oil well) and 1000 foot (conventional gas well) AOR distances in the final rule. The only remaining "data" provided by DEP in the RAF is vague reference to stray migration incidents between 1984 to the present.[33] However, this reference fails to specify exactly what subset of these incidents, if any, was attributable to conventional operations and the distances associated with such instances. Without this information, it is impossible to determine the need for the 500 foot area of review or its application specifically to conventional operators.

It should be noted that, during work on the AOR Guidance Document, the DEP provided to Guidance team members a 41-page Power Point presentation prepared by DEP entitled "Area of Review (AOR) Geometry Study." The DEP asserted to Guidance team members that the Power Point contained information justifying the 500 foot (conventional oil) and 1000 foot (conventional gas) distances. It is obviously not possible to have dialogue upon a document introduced by the DEP so late in the process and to such a limited group of recipients. However, a geologist and member of PGCC has written comments about the Geometry Study and the inappropriateness of

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[31] October 29, 2015 Webinar held by Pennsylvania Department of Environmental Protection and the Conventional Oil and Gas Advisory Committee ("COGAC").
[32] RAF at p. 185.
[33] RAF at p. 20 ("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").

the 1000 foot radius area as it applies to conventional gas development in southwestern Pennsylvania. The geologist's comments are contained at Attachment 6. While PGCC does not ask the IRRC to render a ruling as to the technical merits of the geologist's comments versus the DEP's Geometry Study, PGCC does ask for recognition that data on the topic is available, that DEP's claim in the 2013 RAF that it relies upon no data is spurious, and that DEP's method of approaching the data discussion has made it impossible to have reasonable dialogue as to the relevant distances or achieve the goal of consensus as to same.

Indeed, and perhaps most important, in fashioning its AOR distances of 500 feet for oil wells and 1000 feet for conventional gas wells, the DEP overlooked the most reliable and prevalent data available. The well spacing employed by well operators is critical data because new conventional wells are spaced to maximize economic development of oil and gas fields. If wells are spaced too close such that communication occurs between wells, the areas drained by the wells are overlapping; an overlap would be wasteful inasmuch as it would reduce the economic return of both overlapping wells. On the other hand, if wells are spaced too far apart there are gaps in the areas drained by the wells, and oil and gas are wastefully left in place. Therefore, over the course of hydrofracturing thousands of wells, Pennsylvania's conventional oil and gas operators have tested and ascertained the communication limits of conventional oil and gas wells in Pennsylvania.

That data is readily available in the form of well spacing maps. If two hydrofractured conventional wells are spaced 450 feet apart, the spacing is demonstrating that the hydrofracture propagation/communication distance is 225 feet or less. (In order to arrive at the maximum communication distance, one measures the space between wells and divides by two.)

Several representative maps are attached, all showing that the DEP's distances of 500 and 1000 feet are not supported by reliable data and that the actual distances are less than half the distances arbitrarily selected by the DEP. For instance, multiple oil fields in Warren County have an average well spacing of approximately 400 feet, without any communication incidents, indicating that fractures travel less than 200 feet. See Attachment 7. Similarly, an oil field in McKean County has an average well spacing of 500 feet, without incident, indicating that fractures travel less than 250 feet. See Attachment 7. Conventional gas fields in Westmoreland, Armstrong and Indiana Counties have an average well spacing of less than 1000 feet, corresponding to an expected fracture distance of less than 500 feet. See Attachment 8.

Given the many paperwork, monitoring, and other burdens imposed by the AOR regulation, the length of the radius (and thus the relevant area of review) is highly impactful. For a conventional oil well, the Department's required radius of 500 feet results in an area of review of 18 acres. If the maximum radius should be 250 feet (as supported by the industry's data) the maximum area of review for a conventional oil well should only be 4.6 acres, a difference of over 13 acres. For a conventional gas well, the Department's required radius of 1000 feet results in an area of review of 72 acres. If the maximum radius should be 500 feet (as supported by the industry's data), the maximum area of review for a conventional gas well should only be 18 acres, which is a difference of 54 acres. Attachment 9 uses Heinz Field to illustrate the size differences of these areas; one can imagine the wasted effort in searching the excess acreage where one must navigate trees, bushes, watercourse, wetlands, irregular terrain, as well as the wasted effort in identifying and sending questionnaires to the multiple surface parcel owners in the areas of excess acreage.

Finally, DEP provided no data supporting the requirement to include active or plugged wells in an operator's review. Therefore, there are no data, let alone acceptable data as defined in the RRA, that justify the AOR provisions. The RAF's reference to the STRONGER report[34] is misplaced, particularly because the report did not make recommendations as to thresholds for review of abandoned, active, or plugged wells.

The Department did not satisfy its burden as to data and the result is an excessive obligation that creates unjustified burdens on conventional operators.

4. *Comments, objections, or recommendations of Committees express the concern that Section 78.52a is not in the public interest.*

Both the Senate Environmental Resource & Energy and the House of Representatives Environmental Resources & Energy Standing Committee have submitted comments in opposition to the proposed rulemaking for conventional operations. With respect to Section 78.52a, the Senate's comments, dated February 2, 2016, stated:

> The absence of a relevant statement of need explaining what deleterious impacts the new AOR provisions will protect against, the absence of a statement of costs informing as to the steps that will have to be taken to comply, and, of course, the absence of the required document(s)...make it frustratingly impossible to understand what is required by the newly proposed AOR provisions.[35]

Both the Senate's and House's comments also incorporated the Report of COGAC to the Environmental Quality Board (EQB). The COGAC Report noted:

> In the face of potential serious economic loss and pollution, the conventional industry is already careful to identify old holes. As a result, communication with old holes is rare...
>
> The preparation and submission of the Monitoring Plan and the thirty day DEP review time are not sanctioned by any statutory authority.
>
> Further, the standards by which the DEP will allow or disallow new well completion are not known. In the Monitoring Plan the well operator must identify surrounding wells; the regulation requires the operator to make the identification by reviewing 'available well databases' and 'historical sources of information.' Despite request the Department has been unable to identify the required databases or historical sources."
>
> The complexity of the new [AOR requirements] is not supported by a rational goal or need. The type of data that would logically drive such a new permitting requirement is a significant number of communication events that were preventable had the well operator conducted a prudent search for old well bores. The Department has not provided that statement of need. In the experience of the COGAC members that need does not exist

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[34] State Review of Oil and Natural Gas Environmental Regulations, Pennsylvania Follow-Up Review, 2013 (available at http://www.strongerinc.org/wp-content/uploads/2015/04/Final-Report-of-Pennsylvania-State-Review-Approved-for-Publication.pdf).

[35] February 2, 2016 Comments of the Environmental Resources & Energy Committee, Senate of Pennsylvania (hereinafter "Senate EREC Comments") at p. 5.

> because of the very infrequent instances of communication and because of the very strong incentive each well operator has to diligently avoid a communication event.[36]

In short, the House and Senate Committees' comments, as well as COGAC's Report, firmly support the conclusion that Section 78.52a is contrary to the public interest as it is unclear, unsupported by any compelling need, and devoid of a proper cost analysis, especially with respect to impacts on small businesses.

D. 78.65 – Site Restoration

Section 78.65 of the final rule requires conventional operators to meet certain land restoration requirements associated with activities at a well site at two different points in time – post drilling (the production phase) and post plugging (end of life of the well).

First, Section 78.65(d) provides that disturbed areas not included in a restoration plan and "other remaining impervious surfaces" must comply with Chapter 102.8 provisions, which specifies post-construction stormwater ("PCSM") and erosion control measures that do not currently apply to conventional operations less than 5 acres.

Second, Sections 78.65(a)(2) (post plugging), 78.65(b)(5) (which appears to apply to both post drilling and post plugging restoration), and 78.65(c) (extension requests), require operators to restore sites to "approximate original conditions," (AOC) defined as:

> Reclamation of the land affected to preconstruction contours so that it closely resembles the general surface configuration of the land prior to construction activities and blends into and complements the drainage pattern of the surrounding terrain, and can support the land uses prior to the applicable oil and gas operations to the extent practicable.

This new requirement is nowhere to be found in Act 13, the Clean Streams Law or elsewhere, is contrary to current practice, and is unjustified and unnecessary for conventional well sites.

1. *Section 78.65(d) will cause conventional operators to incur significant costs that are not offset by an attendant benefit or need.*

IRRC's comments to the proposed rule requested that EQB "explain in the Preamble and RAF of the final-form regulation how the requirements in [78.65(d)] reasonably and adequately balance protection of the public health and natural resources against the fiscal impact on the oil and gas industry."[37] The final rule's RAF concluded that there would be no new costs associated with this section (including 78.65(d)), stating that:

> To the extent that an operator would incur the costs [stated by industry], they would incur those costs regardless of the status of Section 78.65 because they are costs associated with complying with Act 13 and Chapter 102.[38]

This characterization of current obligations is highly inaccurate. Conventional well operators are not currently obligated to design or construct PSMB best management practices ("BMPs") for

[36] House EREC Comments, Attachment A at p. 18.
[37] IRRC Comments at p. 16.
[38] RAF at p. 101.

sites under five acres or to restore well sites to AOC. As for PCSM BMPs, PGCC obtained and has provided cost estimates showing total possible expenses for this new requirement of $45 million per year for newly constructed conventional wells.[39] See Attachment 10. These cost estimates were provided by two civil engineering firms for designing and/or constructing post-construction stormwater management BMPs that would be required under Section 78.65(d). The estimates show that the per-site costs could range from $33,600 to $84,000, depending on the site characteristics. These costs are not currently incurred by conventional operators that do not obtain permits for earth disturbance less than five acres.

In addition, a requirement for PCSM BMPs for conventional well sites would significantly increase the footprint and earth disturbance associated with these operations, which is entirely contrary to the purported goal of reducing impacts. Especially when located in state and federal forests, additional tree cutting required to install PCSM BMPs is contrary to the expectations and interests of those who maintain and those who utilize the forests for recreational purposes.

These new burdens, including Section 102.8(g) (which requires implementation of stormwater analysis and construction activities), are not currently imposed on well sites under five acres under Chapter 102. The requirements under Section 78.65(d) are unreasonable and contrary to existing practice and regulations developed under Clean Streams Law. DEP verbally acknowledged this at the COGAC webinars on October 29, 2015, where it stated that it was not their intent to require conventional operators to have to comply with these more onerous requirements.[40] But the language of the final rule has retained the obligations, despite DEP's protestations to the contrary.

2. *Revisions to Section 78.65 are unreasonable, unclear, and without compelling need.*

The final rule's RAF states that Sections 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 the potential to cause pollution.[41]

The RAF, in this as in other places, failed to separate this statement of need to distinguish between conventional and unconventional operations. Conventional well sites are some 25 to 40 times smaller than unconventional well sites. As seen in Attachment 11, conventional well sites carry a small footprint and are readily stabilized by vegetation (grasses in the short term and saplings and trees as the site matures).

Compliance with 78.65(a)(2) (post plugging) would more likely have a net negative impact on public resources. By the time of plugging, conventional well sites are of significant age (decades) and have become wooded since the completion of drilling. These new post plugging restoration requirements would have the counterproductive effect of requiring operators to cut down trees and regrade slopes and surfaces that have long since stabilized. The photographs in Attachment 13 demonstrate the difficulty, with the first photograph showing a recently constructed sidehill cut

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[39] 2014 PGCC Comments at p. 34.
[40] October 29, 2015 Webinar held by Pennsylvania Department of Environmental Protection and COGAC.
[41] IRRC Comments at p. 36.

without trees, and the second showing an older wellsite with saplings now growing upon the sidehill cut. Returning the well sites to AOC would generally destroy the vegetation and trees that grow over time on those slopes. Returning well sites to AOC would also, in some instances, require the destruction of wetlands that have emerged around wells over time, a result contrary to a strict regulatory framework for the protection of wetlands. A representative photograph of wetlands surrounding a well that could be subject to destruction from implementation of the final rule's site restoration requirements is attached in Attachment 12.

Strict compliance with this section is contrary to sound environmental management and could create the very stormwater runoff and flooding scenarios that the RAF states the revision is intended to avoid. To the extent that these outcomes were not intended by DEP, the final rule text is fundamentally unclear. In addition to the failure to contemplate the numerous unintended consequences of the requirement, there is no description of a compelling need for such restoration requirements in the RAF, especially when considering that most conventional well sites have such a small footprint, typically less than about 1/5th of an acre.[42]

3. *Legislative Committee comments reflect the concern that Section 78.65 is contrary to the public interest.*

Both the House and Senate Environmental Resource & Energy Standing Committees, through adoption of the COGAC report, have voiced disapproval of Section 78.65:

> [78.65] is a significant departure both from existing regulations as well as from the initial version of the revised regulations first published in 2013. Like other regulatory provisions discussed above this new and significant change is not supported by the necessary statement of need, the analysis of costs and the consideration of alternatives for small business.[43]

In short, to the extent the DEP implements the rule as written, Section 78.65 includes numerous unreasonable subsections and will impose excessive costs on conventional operators, without any likelihood of benefits that would outweigh the costs and burdens to conventional operations.

E. Section 78.66 – Reporting and remediating spills and releases.

Section 78.66 of the final rule requires reporting and remediation of spills and releases of regulated substances on or adjacent to well sites and access roads, according to a new process. Chapter 78.66 currently requires immediate notifications under Section 91.33 when spills have the potential to threaten waters of the Commonwealth, and notice within two hours for reportable releases of brine (over 5 or 15 gallons, depending on the concentration of the brine). Under the revision, the operator would be required to sample water supplies for which there is a "potential for pollution," and provide replacement water supplies as per Section 78.51. With respect to remediation requirements, operators would be required to adhere to procedures and standards under Act 2 for spills or releases greater than or equal to 42 gallons. The Act 2 process is voluntary for all other entities in Pennsylvania.

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[42] House EREC Comments, Attachment A at p. 27.
[43] House EREC Comments, Attachment A at p. 27.

As demonstrated below, this revision is contrary to the public interest because it imposes unreasonable costs upon conventional operators, and the revisions are not justified by attendant need or benefits proportional to its costs.

1. The costs imposed under Section 78.66 are significant to conventional operators.

In its comments to the proposed rule, IRRC requested that "EQB explain in the Preamble and RAF of the final-form regulation how the compliance requirements in the [remediation] subsection reasonably and adequately balance protection of the public health and natural resources against the fiscal impact on the oil and gas industry."[44]

In the final rule's RAF, DEP stated that the "purpose of the provisions in [Section 78.66] is to clarify the requirements regarding reporting and remediating spills and releases of regulated substances on or adjacent to well sites and access roads," and that "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."[45] This generic statement of need does not in any way explain why the existing rule is inadequate for these purposes.

Nor has DEP provided any cost estimate in the RAF, stating that "it is not possible . . . to predict the number of spills or releases that will occur at well sites."[46] DEP also dismissed the notion of there being significant costs on the basis that the purpose of the complete revision of Section 78.66 is primarily for "clarification" purposes rather than substantive changes. This characterization is surprising in its degree of inaccuracy.

The amendments to this section introduce significant substantive changes to the existing spill and release remediation requirements. Under the current framework, such incidents have been addressed through a 2013 PADEP guidance document entitled "*Addressing spills and releases at oil and gas well sites or access roads*" (800-5000-001). The policy document references certain remediation standards, but does not make compliance with the Act 2 process mandatory, as it could not without statutory or regulatory authority. The revisions in this section would not only make compliance with Act 2 process mandatory, but would impose additional reporting requirements in timeframes above and beyond Act 2 requirements and well beyond the current policy and guidance.

Under the final rule, the flexibility that was afforded under the current policy is to be removed, causing operators to incur significant additional costs. Based on cost estimates provided by PGCC, the total burden on conventional operators ranges from $1 million to $50 million annually.[47] Under current law, conventional operators, like other entities across the Commonwealth, may voluntarily choose to utilize the Act 2 process based upon the circumstances of a particular spill. Please see the attached costs of an Act 2 cleanup for a 60 barrel oil spill totaling close to $200,000 (see Attachment 14). And the costs of a cleanup under Act 2 do not even capture the new costs that would be added by the revision that requires additional reporting and time frames that are not part of the Act 2 process. A recent brine spill of

[44] IRRC Comments p. 16-17.
[45] RAF at p. 39.
[46] *Id.* at p. 123.
[47] Memorandum from PGCC to IRRC dated October 12, 2015, Exhibit B at p. 4.

270 gallons required removal of 20 tons of soil and cost approximately $23,000, the vast majority of which was testing and preparing reports to DEP's satisfaction (see Attachment 14). Costs alone do not tell the whole story of the burden to be imposed. These costs, however, are not, as discussed below, justified by any statement by DEP as to why the existing law must be changed at all.

2. *Section 78.66 does not provide for any alternatives for small businesses.*

A common remediation method used and recommended by the United States Environmental Protection Agency ("EPA"), and employed elsewhere in the nation, is bioremediation. Under EPA guidance, successful bioremediation of petroleum-related spills occurs through natural attenuation, including in-site biodegradation.[48] Such methods entail excavating and aerating contaminated soils, incorporating organic matter within, and planting vegetation and/or grass on the surface. According to this guidance, the bioremediation process is complete when vegetation persists. Such an alternative would be an appropriate small business alternative, yet nowhere was it considered in the RAF. This alternative is a strong example of well-known and successful remediation methods that DEP failed to consider, and one that is particularly appropriate for conventional oil and gas operations in Pennsylvania.

3. *There is no attendant need associated with Section 78.66, which is unreasonable and not more protective of public health than the current regulatory requirements.*

The revised remediation requirements of Section 78.66 are not backed by any attendant need or public health benefits and are unreasonable in light of the significant costs described above.

In its prior comments, IRRC requested that EQB state "what is the need for . . . additional requirements" under Section 78.66(b) pertaining to the additional notification requirements beyond that of Section 91.33.[49] The final rule's RAF lacks any specific description of why the additional reporting requirements are more protective of public health or otherwise address some overarching necessity.

The lack of any attendant need for more onerous obligations is all the more apparent because several other programs, including the Clean Streams Law and 25 Pa. Code Section 91.33 already impose reporting and cleanup obligations for spills and releases, including those that occur at oil and gas operations. The most typical constituents that are spilled at sites are brine and oil, which are not hazardous in nature and do not pose significant threats to public health or the environment warranting additional requirements. Other than to point to public interest, DEP has not explained why or how any additional regulation of spills on well sites is needed.

Excessive obligations for conventional operations are unreasonable and arbitrary to the extent that they regulate releases of brine more stringently than hazardous materials, suggesting that the rationale for the revision is not driven by public health considerations.

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[48] See "*The Practical Application of Bioremediation Techniques as a Removal Response Option at Oil Spill Sites in the Northwestern Pennsylvania Oil Patch*," Vincent E. Zenone, 2006, US Environmental Protection Agency Region III (available at https://archive.epa.gov/emergencies/content/fss/web/pdf/alleniii_1.pdf).

[49] IRRC Comments at p. 16.

4. *Legislative Committee comments reflect the concern that Section 78.66 is not in the public interest.*

Both the House and Senate Environmental Resource & Energy Standing Committees, through the COGAC report, stated substantive concerns with Section 78.66:

> [B]y preparing regulations in a process that is not data driven, the DEP has arrived at requirements that involve extraordinary new cost (Act 2 cleanup mandates), without any measurement of the benefit yielded by that extraordinary cost. Similarly, the DEP has arrived at the mandate for such extraordinary costs without the necessary analysis of alternatives for small business or the consideration of whether the extraordinary cost is in balance with the statutory mandate of 'optimal' development of the Commonwealth's oil and gas resources. These are fatal oversights that require the current proposal to be abandoned in favor of compliance with the rigor expected of agencies adopting new burdensome and highly expensive regulations.[50]

Section 78.66 of the final rule is contrary to the public interest as it imposes unreasonable costs upon operators and is not supported by any attendant need or benefits proportional to those costs.

F. Section 78.57 – Control, storage and disposal of production fluids

Under Section 78.57 of the final rule, operators are prohibited from using open top structures and pits to store brine and other fluids produced during well operation. Any wastes stored at a well site that are not generated from the site or are beneficially reused must be permitted under the solid waste program. In lieu of such storage mechanisms, underground tanks used by operators would be required to be constructed and maintained in accordance with "sound engineering practices adhering to nationally recognized industry standards and manufacturer's specifications." In addition, both aboveground and underground tanks would be required under Section 78.57(f) to adhere to certain corrosion control requirements. In particular, aboveground tanks would be required to comply with 25 Pa. Code 245.531-534, under the storage tank program.

In its comments, IRRC requested that DEP explain "how [the corrosion control provision] reasonably and adequately balances protection of the public health and natural resources against the fiscal impact on the oil and gas industry," and "how this provision aligns with the intent of the General Assembly and Act 13.[51]

The final rule's RAF responded by stating 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," and that any costs might be mitigated because "the final rule does not require retroactive application of the corrosion control requirements."[52] The DEP's assessment in the RAF fails to properly address IRRC's concerns and does not correctly account for the degree of costs that would be imposed on conventional operators. In addition, the final rule fails to provide any data or other supporting information to impose such significant burdens on the industry.

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[50] House EREC Comments, Attachment A at p. 31.
[51] IRRC Comments at p. 11-12.
[52] RAF at p. 26.

1. Section 78.57 imposes significant costs on conventional operators.

In the RAF, DEP attributed no additional costs to conventional operators to comply with the corrosion control requirements for storage tanks. This reasoning was based on its position that the subsection "simply implement[s] th[e] requirement...under section 3218.4(b) of Act 13."[53] In addition, DEP stated that the provision "would behoove conventional oil and gas operators to provide corrosion protection for [tanks] because it can extend the useful life of the tank significantly at a fraction of the cost of replacing the tank."[54]

DEP's analysis is incorrect. Section 78.57(f) is not a mere restatement of Section 3218.4(b) of Act 13. That provision does require "applicable corrosion control requirements in the department's storage tank regulations." The tank program includes several exceptions for tanks used in oil and gas operations that are not acknowledged in the final rule. Section 78.57(f) would impose compliance whether the regulation is "applicable" or not. Therefore, the final rule will impose a requirement that not only goes beyond the statute, but exceeds the scope of DEP's authority provided under Act 13.

Considering this, the costs to comply with the requirements of Section 78.57(f) cannot be said to be $0. Cost estimates obtained from PGCC members indicate that installation of cathodic protection for tanks would be approximately $800 per tank. PGCC previously estimated that there are 150,000 tanks currently used in conventional operations across Pennsylvania and the Department accepted the accuracy of this figure.[55] That requirement, alone, would cost the conventional industry $120 million[56]. At page 115 of the RAF, the Department already acknowledges that this section's additional requirement of secondary containment would cost the conventional industry an additional $20 million per year. The total of $140 million for compliance with all of section 78.57, in year one, would cripple the industry regardless of all the other newly proposed revisions. The Department knows the conventional industry's production and the Department can easily do the calculations that show that at today's commodity prices the conventional industry grosses some $1/2 billion in revenue. Remarkably, the Department's financial analysis never takes note that this single regulatory section (78.57) would consume 1/3 of the conventional industry's gross revenue. Indeed, the Department is entirely silent on the cost analysis for implementing the corrosion control requirements and, as a result, it cannot engage in any balancing of costs against public health or environmental benefits.

Moreover, the DEP's statement that the industry can simply employ non-metallic tanks reflects a sharp lack of understanding. To maintain necessary viscosity of fluids during the five months when below-freezing conditions prevail, conventional tanks must be heated. They are heated with natural gas flame heaters inserted in heat tubes, an application which cannot be performed with non-metallic tanks. Even if non-metallic tanks were to be used, the DEP's RAF does not account for the billion+ dollars it would require to convert the 150,000+ tanks currently in use. Finally, non-metallic tanks are used in some small volume/non-heat treatment situations. However, their

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[53] RAF at p. 117.
[54] *Id.*
[55] RAF at p. 115.
[56] It is remarkable the DEP has no record of an agenda, meeting minutes, or actual costs showing an effort to ascertain what it would cost to comply with its proposed regulatory section.

use is limited due to UV degradation of the non-metallic materials and the ensuing high replacement cycles that result.

G. Other sections that raise concerns that require more time to address fully.

1. Section 78.55 (control and disposal planning) is fundamentally unclear and may result in significant costs imposed on conventional operators.

Section 78.55 requires conventional operators to develop a "site specific" preparedness, prevention, and contingency (PPC) plan. IRRC's comments asked EQB whether the "Commonwealth's natural resources [would] be adequately protected if the regulation allowed conventional operators to prepare one PPC plan for multiple sites."[57] The final rule's RAF states that "there may be instances where the operator finds that a PPC plan prepared for one well site is applicable to another site…It is not the intent of this rulemaking to require each PPC plan be separately developed and different for each well site."[58] The RAF also states that "this rulemaking does not require persons to post PPC plans at sites at all times."[59] Section 78.55 of the final rule, as worded, however, remains unclear and fails to address IRRC's concern with the regulatory text.

First, requiring the development of an individual PPC plan for each site, as the express language requires, would result in the imposition of total costs of up to $33 million in the first year. [60] Considering the typical placement of wells on a network-wide perspective indicates how unreasonable the PPC requirement is. Typically, between 2 and 40 wells may feed into a common tank battery, which is located in proximity to the wells it services. The absurdity of developing and maintaining a PPC at each individual well is revealed by the photos in Attachment 15, in which adjacent wells (and hence, potentially "site specific" PPC plan locations) are visible from foreground wells, and are separated by only tens of steps away from each other. Considering the close proximity of such well sites, there is no need, let alone a compelling need, for maintaining separate PPC plans with such close distances.

The need to develop individual PPC plans is largely fruitless because existing PPC plans for different sites already share a high degree of commonality. As shown by the example PPC plans included in Attachment 16, most PPC plans contain similar provisions for spill leak prevention and response measures, and emergency response countermeasures. Requiring a site-specific PPC plan to be developed is an unnecessary endeavor, because site specific information will not vary.

The rulemaking's RAF does not discuss any reason as to why Section 78.55 must be more onerous than that under analog PPC requirements in other programs, nor does it provide any data in support, or accommodations for small businesses, as required under Section 5.2(b) of the RRA. The significant burdens that would be placed upon operators due to the express language in the rule are not justified by any accompanying benefit.

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[57] IRRC Comments at p. 10.
[58] RAF at p. 21.
[59] *Id.*
[60] March 2014 PGCC comment

2. *Sections 78.56(a)(8)-(10) (Temporary Storage) impose substantial costs on conventional operators without demonstration of the need for such requirements or the public health benefits specific to regulation of conventional operations.*

Under Section 78.56 of the final rule, "regulated substances" that are used at or generated at a well site are required to be contained within DEP-approved pits or tanks for temporary containment during drilling and completion activities. Under this section, pits are required to be constructed to new design specifications, including a synthetic flexible liner with a coefficient of permeability of no more than 1E-10 cm/sec, and with a minimum thickness of at least 30 mils unless otherwise approved by the DEP.

In its comments, IRRC requested that EQB "explain in the Preamble and RAF of the final-form regulation how the technical requirements for pit liners in this section reasonably and adequately balance protection of the public health and natural resources against the fiscal impact on the oil and gas industry."[61]

In the final rule's RAF, DEP stated that "the purpose of these provisions is to ensure that temporary storage at the well site . . . protects public health, safety and the environment [and to] minimize spills and releases into the environment."[62] DEP's conclusion, that the liner and other requirements for pits are necessary to be protective of the environment and public health, is unsupported by any data. DEP has failed to provide any counter-balance against the significant costs to conventional operators for these new requirements related to pits that might be used for hours or days, rather than weeks, months or years.

a. *Section 78.56 imposes significant new costs on conventional operators not recognized by the Department due to the Department's mathematical error.*

At pages 23 and 113 of the RAF, the Department critiques the pit liner costs submitted by the conventional industry and sets forth its own calculations. At both of those pages, the Department deals with the typical pit size of 10 feet in width, 30 feet in length, and 8 feet in depth. The conventional industry agrees this is a reasonable size. However, the Department mistakenly concludes the required liner area is only 650 square feet. The industry disagrees. Any standard volume calculator shows that the volume of that size pit is 2400 square feet; additionally the pit liner must be extended on the surface of the ground around the pit in order to secure the liner in place and to collect any fluids that splash in the pit. The actual required liner for that size pit is a minimum of 3200 square feet, some 5 times larger than the mistaken figure employed by the Department.

The weight and cost of the 3200 square foot 20 mil liner is 320 pounds and $768, respectively. The weight and cost of the 3200 square foot 30 mil liner is 473 pounds and $1280, respectively. The Department mistakenly calculates the weights as 33 and 62 pounds, respectively. And the Department assumes no cost for equipment to install liners because the Department miscalculated the weights. In fact, the 20 mil liners can and are installed by a multi-person crew; however, the weight of 320 pounds is at or near the maximum that can reasonably be manhandled. In the experience of the industry, the conversion to a 30 mil liner and its weight of 473 pounds will

[61] *Id.* at p. 11.
[62] RAF at p. 22.

absolutely require the use of machinery to unroll and place the heavier liner. Therefore, PGCC maintains that the commenters' original calculations of $1800 for the 30 mil liner were correct, reflective of a $1300 materials cost along with an additional $500 installation cost per well. The correct figure is some 7 times greater than what the DEP estimated in the RAF (at $260 for 30 mil liner materials), and some 17 times greater than the estimated materials cost for a 20 mil liner (at $156), equating to a very significant new expense for conventional operators.[63] As discussed below, these substantial costs far outweigh any public health and environmental benefits, which have been unspecified by DEP.

b. *DEP has failed to establish the need, or protective effects of this section, which is also fundamentally unclear.*

The 30 mil liner requirement in this section is unsupported by any specific data, and, in fact, may hinder the use of liners that may be more effective. Several 20 mil liner products exist that have been shown to possess tear strength, puncture resistance, and Mullen burst properties that are superior to 30 mil counterparts. By insisting upon the use of a 30 mil liner, DEP is ignoring the potential benefits of 20 mil liners in terms of lighter weight and greater flexibility (in addition to the above-described cost savings). For example, see the February 20, 2016 letter provided by Inland Tarp & Liner (see Attachment 17).

The revised language of Section 78.56(a) recognizes that the 30 mil liner requirement may be unnecessary, as Section 78.56(b) allows for operators to seek approval of an alternative practice "which provide[s] equivalent or superior protection." In the RAF, the DEP notes that "a small but significant number of liner products with a 20 mil thickness" were approved by DEP previously, but that "the exception should [not] define the rule."[64] An example of such an "exception" is Horner Plastic's 2080B 20 mil liner product, which was approved by DEP in December 2002 (approval letter and associated product specifications attached as Attachment 18). Note that DEP concluded that the 20 mil liner would provide protection "equal or superior" to the 30 mil liner requirement in 78.61 and 78.62, which apply to permanent disposal in pits. This section, 78.56, applies to temporary storage of materials during drilling and completion activities, where the need for a 30 mil liner is far less likely.

Nowhere in the RAF did DEP engage in a comparative, quantitative analysis of the strength and durability properties of various types of 20 mil liners against 30 mil counterparts for various purposes, whether temporary storage or permanent disposal. The final rule's adoption of a blanket requirement to use 30 mil liners without sufficient consideration of the magnitude of benefits, if any, from requiring greater thickness as compared to costs, fails to address IRRC's concerns. DEP has provided no reason whatsoever to alter the existing requirement to use liners of "sufficient strength and thickness to maintain integrity of the liner."

3. ***Section 78.58 (Onsite Processing)*** *imposes substantial costs on conventional operators without demonstration of the need for such requirements or public health benefits specific to regulation of conventional operations.*

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[63] RAF at p. 113-114.
[64] RAF at p. 23.

Under this section, operators are required to secure DEP approval to process onsite fluids that are generated at a well site. Partially excepted from this requirement are fluid aeration, filtering of fluids, and mixing fluids with freshwater, which must be conducted within secondary containment. In addition, operators processing fluids or drill cuttings are also generally required to develop an action plan for monitoring and responding to radioactive material produced by any treatment processes used, along with training, notification, recordkeeping and reporting protocols. In its April 2014 comments, IRRC asked the EQB to "explain in the Preamble and RAF of the final-form regulation how the requirements for onsite processing in this section reasonably and adequately balance protection of the public health and natural resources against the fiscal impact on the oil and gas industry."[65]

The final rule's RAF states that the purpose of the section is "to encourage recycling and reuse in hydraulic fracturing operations . . . [and] to ensure that processing activities are conducted in a way that protects public health, safety and the environment."[66] In addition, the RAF states that this section is "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."[67] This explanation fails to properly account for the extent of costs imposed on conventional operators, and overstates the need for any revision to existing regulation, thus failing to establish any balance between the fiscal impact on the industry and the protection of the public health and environment.

In the RAF, DEP stated that it believed no additional costs would be imposed on conventional operators through implementation of the radiation protection action plan, and it did not explicitly analyze costs for the remainder of requirements under 78.58.[68] To justify its estimate, DEP stated that "conventional operators do not generally conduct processing on well sites."[69] However, it acknowledged that "some number of operators may wish to conduct such activities," and estimated a cost of $10,000 for those who would be required to develop a plan.[70] DEP made no estimate as to the overall cost to the industry, inclusive of those who may wish to conduct onsite processing.

In addition, nowhere in the RAF is there any cost analysis on the requirement to obtain DEP approval for onsite processing. Potential costs that could be introduced under this section are additional expenses for storage during the time when approval is pending and preparation costs for submittals. As a result, DEP failed to address IRRC's specific concern – the extent of fiscal impacts "on the industry," which would include those operators who indeed conduct onsite processing.

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[65] IRRC Comments at p. 12.
[66] RAF at p. 29.
[67] *Id.* at p. 30.
[68] *Id.* at p. 118.
[69] *Id.*
[70] *Id.*

a. DEP has failed to establish that Section 78.58 is needed to protect the public health and environment and is unsupported by any data.

Against the un-estimated costs that could be incurred by conventional operators under this section, DEP failed to substantively characterize the degree of public health and environmental benefits that would result.

In fact, DEP's own past investigations into these issues establish that onsite processing activities, especially by conventional operators, are unlikely to pose any meaningful threat to the public health and environment. In its January 2015 report on Technologically Enhanced Naturally Occurring Radioactive Material (TENORM), DEP concluded that there was little potential for radiological exposures to workers and the public from handling and storage of drill cuttings, as well as fluids used in or generated from operations at well sites.[71] The radium 226 and 228 concentrations associated with each of these materials were, on average, well below the hazardous materials threshold under U.S. Dept. of Transportation regulations, and were at or near naturally-occurring background levels.[72]

These findings were made under the current regulatory framework, which does not require preparation of radiation protection action plans. The study also made no such recommendation with respect to well operators. As a result, there is no "balance" between public health and fiscal impacts to the industry to be made, simply because there are essentially no public health benefits that can result from this section's obligations.

H. Compliance with the Regulatory Review Act

Section 5.2(b)(1)

As can be seen from the comments above, PGCC believes that a central failing of the EQB has been its wholly inadequate consideration of the economic and fiscal impacts of the regulation on the conventional oil and gas industry in Pennsylvania. And contrary to the DEP's statements in the RAF that it "reached out to well operators, subcontractors and industry groups to derive the cost estimates of the final-form rulemaking,"[73] the DEP's March 2016 response to PGCC's Right to Know request revealed no evidence of meeting agendas or minutes with COGAC or any of the three conventional industry trade groups to discuss or test the accuracy of the costs set forth in the RAF. Instead, the Right to Know response simply includes two emails with attachments from unknown persons providing estimates that DEP ultimately ignored.

The attached affidavits from PGCC and COGAC (included as Attachment 3) further underscore the lack of any effective "reaching out." PGCC, PIOGA and PIPP, and their members, have tried throughout the rulemaking to engage in dialogue with the Department regarding costs and fiscal impacts but have been unsuccessful in obtaining such interaction with the Department. While the

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[71] Technologically Enhanced Naturally Occurring Radioactive Materials (TENORM) Study Report, Pennsylvania Department of Environmental Protection, January 2015 at p. 9-1 to 9-2.
[72] *Id.*
[73] RAF at p. 85 and 104.

bases of DEP's cost estimates remain unclear, it is clear that "reaching out" to industry was not the source of the cost estimates for the final rule.

Section 5.2(b)(6)

PGCC previously provided a letter to IRRC on October 12, 2015 that detailed the many procedural failings of DEP/EQB in this rulemaking process. Those failings have undermined the value of the public comment process, which was severely disadvantaged by the absence of any statements of need for revisions, or any acceptable data to explain and clarify such needs, the wholly inadequate analysis of impacts and costs to be borne by conventional operators, and the absence of a discussion about alternatives or exemptions for small businesses. Fundamental procedural failings such as these cannot be cured in a final rule, as evidenced by the significant substantive concerns described above. PGCC incorporates its October 2015 letter by reference here and in the interest of efficiency, will not repeat those many procedural failings here. We respectfully request that these two comments be read together, considering the current comment to be more of a substantive than procedural review.

III. Conclusion.

The spreadsheets attached to the 2014 PGCC Comments were calculated on the basis of $92 oil and $4.50 natural gas pricing. The spreadsheets demonstrated that even at those high commodity prices, the final form regulations now under consideration yielded a crippling effect upon Pennsylvania's conventional oil and gas industry. Before the final RAF was written, commodity prices had dropped by over two-thirds, with oil moving to less than $30 a barrel and natural gas less than $1.00 an mcf. New conventional wells are not affordable in the current climate as reflected in Attachment 20.

The bust and boom cycle is not new to the oil and gas industry but today's bust conditions underscore the necessity of the RRA's requirements that new regulations must account for impacts upon small businesses, be founded upon an actual need, and not impose hidden costs. Unfortunately, the RAF does not do an adequate job of accounting for the impact upon small businesses, businesses that are also facing a two-thirds drop in gross revenues. Not only are those impacts not properly analyzed, but exemptions and alternative standards are not considered. Despite questions posed by the IRRC and extensive Right to Know requests submitted by PGCC, we remain without an understanding of how the existing regulatory framework is inadequate and why the more extensive regulations are required. And the specific regulatory provisions do not pass the criteria for review under section 5.2 of the RRA.

For these reasons, PGCC respectfully requests that the Chapter 78 Subchapter C final rule be disapproved.

ATTACHMENT 1,

Letters from the Oil and Gas Technical Advisory Board to DEP, dated May 6, 2013 and July 18, 2013

PENNSYLVANIA DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL AND GAS TECHNICAL ADVISORY BOARD

July 18, 2013

Mr. Scott Perry
Deputy Secretary
Office of Oil and Gas Management
Department of Environmental Protection
400 Market Street
Harrisburg, PA 17101

Re: Oil and Gas Technical Advisory Board's Report concerning the Department of Environmental Protection's proposed revisions to 25 Pa. Code Chapter 78, Subpart C, to be promulgated under the 2012 Oil and Gas Act

Dear Mr. Perry:

The Oil and Gas Technical Advisory Board has reviewed the Department of Environmental Protection's proposed revisions to 25 Pa. Code Chapter 78, Subchapter C dated April 2, 2013, and prepared the enclosed Report in accordance with Section 3226(d) of the Oil and Gas Act of 2012. TAB commends the Department for the meetings and discussions it has held with TAB and the public concerning the proposed revisions to Chapter 78 over the last several months, and appreciates the revisions the Department has made to the proposed regulations to accommodate stakeholders' interests. Nevertheless, TAB believes that the proposed regulatory package has not been fully developed and the Report respectfully recommends that the Environmental Quality Board decline to publish the Chapter 78 proposal at its August 20 meeting.

Kindly include this Report with the package of the proposed revisions to Chapter 78, Subchapter C and related materials that the Department will submit to the EQB in advance of the August 20 meeting. We are available to discuss any questions or comments the Department may have.

Sincerely,

Gary E. Slagel

Gary E. Slagel, on behalf of
Robert W. Watson, Ph. D., Chairman
Samuel E. Fragale
Burt A. Waite
Arthur E. Yingling

Pennsylvania Oil and Gas Technical Advisory Board

cc: E. Christopher Abruzzo, Acting Secretary
Department of Environmental Protection
400 Market Street
Harrisburg, PA 17101

Patrick Henderson, Energy Executive
Office of Policy & Planning
Room 238
Main Capitol Building
Harrisburg, PA 17101

PENNSYLVANIA DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL AND GAS TECHNICAL ADVISORY BOARD

May 6, 2013

Mr. Scott Perry, Deputy Secretary
Office of Oil and Gas Management
Pennsylvania Department of Environmental Protection
400 Market St.
Harrisburg, PA 17101

Dear Scott:

As I noted in my previous letter dated April 30, 2013, the Technical Advisory Board (TAB) appreciates the opportunity to review and comment on the Department's proposals for revisions to the Chapter 78 rules, in accordance with our statutory obligation to do so under Section 3226 of Act 13. As you are aware, portions of the proposed rules noted in my previous letter remain a significant concern for TAB and we look forward to providing consultation to the Department on those topics, including issues related to public resources and abandoned wells, standards for impoundments and tank farms, water replacement criteria, and characterization of sludges and other solids.

Accordingly, TAB agreed with your proposal at the April 23rd TAB meeting to move certain new or otherwise unresolved issues (as well as review of forms that will be necessary to implement proposed revisions to Chapter 78) to TAB subcommittees for technical review and discussion. We also expressed the hope that some of the results of this additional review and discussion would be incorporated into the rule package before transmittal to the EQB.

At the April meeting, TAB concurred with the Department's recommendation to submit the current draft rule to the Environmental Quality Board (EQB) for publication this summer, contingent upon formation of the subcommittees to address unresolved concerns. However, given the importance of these outstanding issues and the need to organize and fully engage the subcommittees we believe that the rule package should not be transmitted to the EQB until TAB has had the opportunity to provide input to the Department on these portions of the rule package. With a large number of outstanding issues awaiting TAB review, the current draft of the rule package is not complete. It would be in the best interest of the Department, industry and the public for the EQB to publish a complete proposed rule package that resolves the outstanding issues with the full benefit of TAB's review and input. Given the comprehensive nature of this rule package, and the impacts that it will have on oil and gas operations, TAB also suggests that its recommendations take the form of a written report, as contemplated in Section 3226 of Act 13.

Please let me know what TAB can do to assist in initiating the subcommittee process, which we see as a valuable means by which TAB will have the reasonable opportunity to review and comment on the total package of proposed rules, as required by Section 3226. We look forward to hearing from you soon.

Sincerely,

Gary Slagel, on behalf of

Robert Watson, Chairman

Sam Fragale

Burt Waite

Art Yingling

cc: Alisa Harris

ATTACHMENT 2

Excerpts of S.B. 655 of 2015

HOUSE AMENDED

PRIOR PRINTER'S NO. 650 PRINTER'S NO. 1137

THE GENERAL ASSEMBLY OF PENNSYLVANIA

SENATE BILL

No. 655 Session of 2015

INTRODUCED BY BROWNE, MARCH 23, 2015

AS RE-REPORTED FROM COMMITTEE ON APPROPRIATIONS, HOUSE OF REPRESENTATIVES, AS AMENDED, JUNE 28, 2015

AN ACT

Amending the act of April 9, 1929 (P.L.343, No.176), entitled, as amended, "An act relating to the finances of the State government; providing for the settlement, assessment, collection, and lien of taxes, bonus, and all other accounts due the Commonwealth, the collection and recovery of fees and other money or property due or belonging to the Commonwealth, or any agency thereof, including escheated property and the proceeds of its sale, the custody and disbursement or other disposition of funds and securities belonging to or in the possession of the Commonwealth, and the settlement of claims against the Commonwealth, the resettlement of accounts and appeals to the courts, refunds of moneys erroneously paid to the Commonwealth, auditing the accounts of the Commonwealth and all agencies thereof, of all public officers collecting moneys payable to the Commonwealth, or any agency thereof, and all receipts of appropriations from the Commonwealth, authorizing the Commonwealth to issue tax anticipation notes to defray current expenses, implementing the provisions of section 7(a) of Article VIII of the Constitution of Pennsylvania authorizing and restricting the incurring of certain debt and imposing penalties; affecting every department, board, commission, and officer of the State government, every political subdivision of the State, and certain officers of such subdivisions, every person, association, and corporation required to pay, assess, or collect taxes, or to make returns or reports under the laws imposing taxes for State purposes, or to pay license fees or other moneys to the Commonwealth, or any agency thereof, every State depository and every debtor or creditor of the Commonwealth," ~~in special funds, further providing for expiration.~~ ESTABLISHING THE NON-NARCOTIC MEDICATION ASSISTED SUBSTANCE ABUSE TREATMENT GRANT PILOT PROGRAM; IN SPECIAL FUNDS, FURTHER PROVIDING FOR FUNDING, FOR STATE WORKERS' <-- <--

PAID FOR BY THE MEDICAL ASSISTANCE PROGRAM ON BEHALF OF EACH ELIGIBLE AND ENROLLED CHILD DESCRIBED IN CLAUSE (A).

SECTION 2.6. SECTION 1733-E OF THE ACT, AMENDED OCTOBER 9, 2009 (P.L.537, NO.50), IS AMENDED TO READ:

SECTION 1733-E. PENNSYLVANIA STATE POLICE.

THE FOLLOWING SHALL APPLY TO APPROPRIATIONS FOR THE PENNSYLVANIA STATE POLICE:

(1) THE PENNSYLVANIA STATE POLICE MAY NOT CLOSE A BARRACKS UNTIL THE PENNSYLVANIA STATE POLICE CONDUCTS A PUBLIC HEARING AND PROVIDES 30 DAYS' NOTICE, WHICH SHALL BE PUBLISHED IN THE PENNSYLVANIA BULLETIN AND IN AT LEAST TWO LOCAL NEWSPAPERS.

(2) [(RESERVED).] <u>PAYMENTS MADE TO MUNICIPALITIES UNDER 53 PA.C.S. § 2170 (RELATING TO REIMBURSEMENT OF EXPENSES) SHALL BE LIMITED TO MONEY AVAILABLE. IF MONEY IS NOT AVAILABLE TO MAKE FULL PAYMENTS, THE MUNICIPAL POLICE OFFICERS' EDUCATION AND TRAINING COMMISSION SHALL MAKE PAYMENTS ON A PRO RATA BASIS.</u>

SECTION 2.7. SECTION 1741.1-E OF THE ACT, ADDED JULY 10, 2014 (P.L.1053, NO.126), IS AMENDED TO READ:

SECTION 1741.1-E. ENVIRONMENTAL QUALITY BOARD.

(A) REGULATIONS.--FROM FUNDS APPROPRIATED TO THE ENVIRONMENTAL QUALITY BOARD, THE BOARD SHALL PROMULGATE PROPOSED REGULATIONS AND REGULATIONS UNDER 58 PA.C.S. (RELATING TO OIL AND GAS) OR OTHER LAWS OF THIS COMMONWEALTH RELATING TO CONVENTIONAL OIL AND GAS WELLS SEPARATELY FROM PROPOSED REGULATIONS AND REGULATIONS RELATING TO UNCONVENTIONAL GAS WELLS. ALL REGULATIONS UNDER 58 PA.C.S. SHALL DIFFERENTIATE BETWEEN CONVENTIONAL OIL AND GAS WELLS AND UNCONVENTIONAL GAS

1 WELLS. REGULATIONS PROMULGATED UNDER THIS [SECTION] SUBSECTION
2 SHALL APPLY TO REGULATIONS PROMULGATED ON OR AFTER THE EFFECTIVE
3 DATE OF THIS [SECTION] SUBSECTION.
4 (B) RULEMAKING PROHIBITION.--
5 (1) THE BOARD MAY NOT ADOPT OR PROMULGATE:
6 (I) A REVISION OF 25 PA. CODE CH. 78 (RELATING TO
7 OIL AND GAS WELLS) APPLICABLE TO THE OPERATION OF
8 CONVENTIONAL OIL AND GAS WELLS WHICH WAS FORMULATED OR
9 PROPOSED IN ANY FORM PRIOR TO THE EFFECTIVE DATE OF THIS
10 SUBSECTION; OR
11 (II) A REGULATION APPLICABLE TO THE OPERATION OF
12 CONVENTIONAL OIL AND GAS WELLS WHICH WAS FORMULATED OR
13 PROPOSED IN ANY FORM PRIOR TO THE EFFECTIVE DATE OF THIS
14 SUBSECTION.
15 (2) AS TO ANY RULEMAKING PROCEDURE CONCERNING
16 CONVENTIONAL OIL AND GAS WELLS WHICH WAS PUBLISHED FOR THE
17 BOARD OR THE DEPARTMENT OF ENVIRONMENTAL PROTECTION IN THE
18 PENNSYLVANIA BULLETIN AFTER NOVEMBER 30, 2013, AND BEFORE THE
19 EFFECTIVE DATE OF THIS PARAGRAPH, THE GENERAL ASSEMBLY FINDS
20 AND DECLARES THAT, AS TO CONVENTIONAL OIL AND GAS WELLS:
21 (I) THE RULEMAKING PROCEDURE IS INVALID AS NOT IN
22 COMPLIANCE WITH THE RULEMAKING STANDARDS OF THE ACT OF
23 JUNE 25, 1982 (P.L.633, NO.181), KNOWN AS THE REGULATORY
24 REVIEW ACT.
25 (II) REGULATIONS PROMULGATED UNDER THE RULEMAKING
26 PROCEDURE ARE ABROGATED. THIS SUBPARAGRAPH APPLIES
27 REGARDLESS OF THE DATE OF PUBLICATION OF FINAL-FORM
28 RULEMAKING IN THE PENNSYLVANIA BULLETIN.
29 (C) FUTURE RULEMAKING.--AFTER THE EFFECTIVE DATE OF THIS
30 SUBSECTION, THE BOARD MAY INITIATE THE FORMULATION, ADOPTION OR

1 PROMULGATION OF REGULATIONS FOR OPERATION OF CONVENTIONAL OIL
2 AND GAS WELLS IN ACCORDANCE WITH LAW. THE FORMULATION, ADOPTION
3 OR PROMULGATION SHALL BE ACCOMPANIED BY THE SUBMISSION OF A
4 REGULATORY ANALYSIS FORM WHICH IS PREPARED FOLLOWING THE
5 EFFECTIVE DATE OF THIS PARAGRAPH.
6 [(B)] (D) DEFINITIONS.--AS USED IN THIS SECTION, THE
7 FOLLOWING WORDS AND PHRASES SHALL HAVE THE MEANINGS GIVEN TO
8 THEM IN THIS SUBSECTION UNLESS THE CONTEXT CLEARLY INDICATES
9 OTHERWISE:
10 "CONVENTIONAL OIL AND GAS WELL." A BORE HOLE DRILLED FOR THE
11 PURPOSE OF PRODUCING OIL OR GAS FROM A CONVENTIONAL FORMATION.
12 THE TERM INCLUDES ANY OF THE FOLLOWING:
13 (1) A WELL DRILLED TO PRODUCE OIL.
14 (2) A WELL DRILLED TO PRODUCE NATURAL GAS FROM
15 FORMATIONS OTHER THAN SHALE FORMATIONS.
16 (3) A WELL DRILLED TO PRODUCE NATURAL GAS FROM SHALE
17 FORMATIONS LOCATED ABOVE THE BASE OF THE ELK GROUP OR ITS
18 STRATIGRAPHIC EQUIVALENT.
19 (4) A WELL DRILLED TO PRODUCE NATURAL GAS FROM SHALE
20 FORMATIONS LOCATED BELOW THE BASE OF THE ELK GROUP WHERE
21 NATURAL GAS CAN BE PRODUCED AT ECONOMIC FLOW RATES OR IN
22 ECONOMIC VOLUMES WITHOUT THE USE OF VERTICAL OR NONVERTICAL
23 WELL BORES STIMULATED BY HYDRAULIC FRACTURE TREATMENTS OR BY
24 USING MULTILATERAL WELL BORES OR OTHER TECHNIQUES TO EXPOSE
25 MORE OF THE FORMATION TO THE WELL BORE.
26 (5) IRRESPECTIVE OF FORMATION, A WELL DRILLED FOR
27 COLLATERAL PURPOSES, SUCH AS MONITORING, GEOLOGIC LOGGING,
28 SECONDARY AND TERTIARY RECOVERY OR DISPOSAL INJECTION.
29 "UNCONVENTIONAL GAS WELL." AS DEFINED IN 58 PA.C.S. § 2301
30 (RELATING TO DEFINITIONS).

ATTACHMENT 3

Affidavits of PGCC and COGAC

AFFIDAVIT

COMMONWEALTH OF PENNSYLVANIA :
: ss
COUNTY OF CLARION :

David Ochs, being the duly appointed Chairman of the Pennsylvania Conventional Oil and Gas Advisory Committee (COGAC), a committee appointed by the Pennsylvania Department of Environmental Protection (Department) for the purpose of consulting with the Department in the formulation, drafting and presentation stages of all regulations promulgated under the 2012 Oil and Gas Act, being duly sworn, deposes and says that:

1. As Chairman of COGAC he is familiar with all meetings participated in by COGAC and the Department;
2. In the course of formulating its final form rules relative to Chapter 78 (C) the Department of Environmental Protection (Department) did not reach out to COGAC to discuss costs of the final form rules or to ascertain actual costs of procedures and practices currently engaged in by the COGAC members or the companies' for which they are employed;
3. At the COGAC meeting conducted with the Department on August 27, 2015, the undersigned requested that the Department provide and discuss the financial costs for the regulatory changes proposed by the Department relative to Chapter 78 (C), and that the Department declined to discuss said costs other than indicating the Department's analysis of the costs could be found in the Regulatory Analysis Form.

David Ochs, Chairman
Conventional Oil and Gas Advisory Committee

Sworn to and subscribed
before me, a Notary Public,
this 28 day of March,
2016.

Notary Public

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Michele A. Wice, Notary Public
Clarion Twp., Clarion County
My Commission Expires June 19, 2016
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

AFFIDAVIT

COMMONWEALTH OF PENNSYLVANIA :
: ss
COUNTY OF WARREN :

David Clark, President of the Pennsylvania Grade Crude Oil Coalition (PGCC), a trade group representing individuals and businesses involved in or directly affected by Pennsylvania's conventional oil and gas industry, being duly sworn, deposes and says that:

1. As President of PGCC he is familiar with all correspondence sent and received by PGCC as well as all meetings conducted by PGCC;
2. In the course of formulating its final form rules relative to Chapter 78 (C) the Department of Environmental Protection (Department) did not reach out to PGCC to discuss costs of the final form rules, to ascertain actual costs of procedures and practices currently engaged in by PGCC members concerning conventional oil and gas operations, or to discuss potential alternatives for small businesses relative to the final form rules.
3. On March 14, 2016 PGCC submitted an 88 page document to the Environmental Quality Board (EQB) relative to proposed revisions to Chapter 78 (C), which 88 page document included multiple spreadsheets showing the actual costs of development and operation for numerous conventional gas and oil wells situate in western Pennsylvania; neither the EQB nor the Department thereafter consulted with PGCC concerning any matter contained in the detailed spreadsheet information, yet financial estimates provided by the Department to the IRRC as contained in the 192 page Regulatory Analysis Form are inconsistent with financial information provided by PGCC.

Pennsylvania Grade Crude Oil Coalition

David Clark

David Clark, President

Sworn to and subscribed
before me, a Notary Public,
this 25 day of March
2016.

Michelle L Cassell

Notary Public

COMMONWEALTH OF PENNSYLVANIA
NOTARIAL SEAL
Michelle L. Cassell, Notary Public
Conewango Twp., Warren County
My Commission Expires May 14, 2018
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

ATTACHMENT 4

Summary Chart of Costs Associated With Final Rule
(Submitted as Part of October 12, 2015 Submission of PGCC to IRRC)

Comparison of DEP and PGCC Cost Estimates for Chapter 78

Updated May 11, 2015 to Incorporate 2015 Proposed Changes

Pennsylvania Grade Crude Oil Coalition
PO Box 211
Warren, PA 16365
Phone: (814)230-3033
Email: admin@pagcoc.org
www.pagcoc.org

Regulation	DEP Est. Cost	DEP Overlooked Items	PGCC Est. Initial Cost	PGCC Est. Annual Cost
A) 78.56a6 Secure tanks from trespass (locking valves, lids, etc.)	$40 to $5000 per tank @ 1344 tanks. **Total: $53,360 to $6,670,000**	The proposed regulations apply to all tanks, but DEP makes no cost estimate for the 175,000+ existing tanks.	175,000+ tanks @ $2000 to $6000. **Total: $325 million to $1 billion**	**$20,300,000 to $76,300,000**
B) 78.57(e) Remove Buried Tanks	$0	DEP states it is unable to estimate the # of buried tanks, thus no stated cost. DEP overlooks: 1) Cost to remove 2) Secondary containment required for replaced tanks 3) Replacement of % of tanks 4) Buried for reasons & must modify to adapt	2000 production tanks @ $6750 to $11,000; 15,000 drip tanks @ $3000 to $9000 **Total: $63.5 million to 177 million**	
C) 78.57(c) Install Secondary Containment	1334 tanks per year @ $3000 **Total: 4,002,000**	DEP: 1) Underestimates # new tanks per year 2) Doesn't account for replacement of existing tanks	2750 new wells/year plus replace worn tanks @ $3000 **Total: $25,125,000/year**	**$25,125,000/year**
D) 78.15(f) Public Lands	**No Cost**	Proposed regs regarding public resources: 1) No definition of "harmful impact" 2) No standard for testing reasonableness of mitigation conditions 3) No provision to achieve legislative standard in Act 13[1]	**Total: $23,242,650/year**	**$23,242,650/year**
E) 78.15(f) Special Concern Species (SCS)	**No Cost**	Proposed regs regarding SCS: 1) No definition of or criteria for SCS 2) No regulatory process to govern additions to list	**Total: $11,621,325/year**	**$11,621,325/year**

[1] Act 13 requires protection of public resources to be accomplished while achieving "optimal development of oil and gas resources and respecting private property rights of oil and gas owners."

F) 78.52a & 78.73 Identify Orphan & Abandoned Wells	**No Cost**	DEP states the provisions do not apply to conventional wells. 1) Proposed regulation applies to vertical wells	**Total: $5,500,000/year**	**$5,500,000/year**
G) 78.56 Slope pits 2:1	**No Cost**	DEP is silent as to cost 1) Requirement will increase pit size 10 to 100 x's	**Total: $18,750,000 to $83,750,000/year**	**$18,750,000 to $83,750,000/year**
H) 78.61 & 78.62 Notice & Certification for Drill Cutting Disposal	**No Cost**	DEP is silent as to cost 1) Cost of delay 2) Cost of required expert	**Total: $2,750,000/year**	**$2,750,000/year**
I) 78.61 & 78.62 Notice & Certification for Stimulation Fluids	**No Cost**	DEP is silent as to cost 1) Cost of delay 2) Cost of required expert	**Total: $2,750,000 to $27,500,000/year**	**$2,750,000 to $27,500,000/year**
J) 78.55 Site Specific PPC	**No Cost**	DEP is silent as to cost 1) Proposed regs incorporate 25 Pa. Code 91.34 which addresses both well site and tank storage locations.	**Total: $33 million**	**$25 million/year**
K) 78.65 Site Restoration	**No Cost**	DEP is silent as to cost 1) Proposed regs do not allow for current storage of repair equipment	**Total: $45 million/year**	**$45 million/year**
L) 78.66 Water Supply	**No Cost**	DEP is silent as to cost 1) Proposed regs require new supply at SWDA standard regardless of pre-existing test results	**Total: $825,000 to $61 million/year**	**$825,000 to $61 million/year**
M) 78.59a. and b. Freshwater Impoundments 78.59a. and b	**No Cost**	DEP is silent as to cost 1) Requires pond closure	**Total: $10 million to $14 million**	**$375,000 to $512,500/year**
TOTALS:	**DEP ANNUAL TOTAL:** **$5,389,360 to $12,006,000**		**PGCC FIRST YEAR COMPLIANCE COST:** **$567,063,975 to $1,510,488,975**	**PGCC ANNUAL MAINTENANCE COST:** **$181,238,215 to $387,300,715**

CHANGES PUBLISHED BY DEP IN 2015

Regulation	DEP Est. Cost	DEP Overlooked Items	PGCC Est. Initial Cost	PGCC Est. Annual Cost
N) 78.65 Site Restoration	**No Statement**	1) Imposes requirements from 102.8(g) upon all new conventional wells (requires certified professional, soil tests, and permanent stormwater measures) 2) Requires return to **original** contours, which may be unattainable or contrary to landowner agreements, and is without legal authority 3) New plan requirements 4) New reports	**Total: $74 million to $272 million/year*** *Engineering est. of $22,000 to $84,000 per well for 102.8(g) compliance; $5000 to $15,000 per well for original contour compliance	**Total: $74 million to $272 million/year**
O) 78.52a & 78.73 Area of Review	**No Statement**	1) Hire or provide GPS data for orphan/abandoned wells 2) Surface inspection (including neighboring wells) to determine integrity (standard not defined) 3) Visual monitoring of active & inactive wells (including neighboring wells) (standard not defined) 4) Compliance standard entirely uncertain (what records review, what field survey is adequate; what if well identified in records cannot be located in field?) 5) Additional reporting (monitoring report) and notice requirements (30 days before fracture).	**Accurate estimate will require quotes from engineers or professional surveyors; certain provisions require trespass upon neighboring parcels; extent of record and field research is not made clear.** **Range of $10 million to $50 million/year**	**$10 million to $50 million/year**
P) 78.57(f) & (h) Production Fluids	**No Statement**	1) Monthly inspection obligation	**Unknown. Extent of obligation not defined.**	**Unknown. Extent of obligation not defined.**

		2) Extent to which cathodic protection and similar measures is required is not clearly defined.		
Q) 78.1 Other Critical Communities	**No Statement**	Now includes consideration of **all** species not listed as threatened or endangered, as well as various non-species resources, the list of which is subject to revision without uniform standards or notice and comment rulemaking	**Unknown. Definition now limitless.**	**Unknown. Definition now limitless.**
R) 78.1 Public Resource Agencies	**No Statement**	Defines municipalities, school districts and water purveyors as "public resource agencies" and adds new notice requirements to same.	**Unknown. Definition now limitless.**	**Unknown. Definition now limitless.**
S) 78.15 Permit Application	**No Statement**	1) Adds schools, playgrounds, and wellhead protection areas to the list of public resources that may trigger DEP considerations in well permitting. 2) Subverts Pennsylvania's "due regard" process. 3) New notice requirements.	**Unknown. Extent of obligation not defined.**	**Unknown. Extent of obligation not defined.**
T) 78.51 Water Restoration	**No Statement**	Elevates restoration of affected water supply to the Safe Drinking Water Act Standard or better.	**May be impossible to attain.**	**May be impossible to attain**
U) 78.53 E&S and Stormwater	**No Statement**	New standards incorporate numerous manuals outside ch. 78, effectively creating a vehicle to avoid the rulemaking process through policy revisions	**Compliance with incorporated manuals not currently required. Extent of expected compliance unknown.**	**Compliance with incorporated manuals not currently required. Extent of expected compliance unknown.**
V) 78.66 Spills and Releases	**No Statement**	Eliminates alternate methods for spill cleanup and increases the reporting and cleanup obligations beyond those required for Act 2 attainment, with deadlines uniquely punitive to oil and gas operations (with lesser obligations for other industries). Effectively eliminates the legislature's distinction between tanks for oil and gas operations	**How to quantify cost of removal of tons of soil for a spill of 43 gallons of brine? $ 1 million to $50 million/year**	**How to quantify cost of removal of tons of soil for a spill of 43 gallons of brine? $ 1 million to $50 million/year**

		and regulated tanks storing hazardous substances. Greater documentation including sampling.		
W) 78.67 Borrow Pits	**No Statement**	1) New requirements incorporate Chapters 102 and 77, contrary to the existing exemption in the Oil and Gas Act for borrow areas 2) New registration requirement 3) Inspection by qualified personnel	**What are requirements of qualified inspector?**	
X) 78.70 Brine Spreading	**No Statement**	Multiple new requirements rendering brine spreading impractical	**Will brine treatment be allowed at Warren, Franklin and elsewhere?**	
Y) 78.15(b.1) Permitting near Wetland	**No Statement**	New permit standards if within 100' of wetland greater than one acre or any E.V. wetland	**Requires analysis of # of well sites in affected areas**	
Z) 78.121 Annual Reporting	**No Statement**	Increases paperwork/reporting data required in annual report	**$500,000 to $2 million**	**$500,000 to $2 million**
AA) 78.57a. Centralized Tank Storage	**No Statement**	Extraordinary new requirements for tank storage beyond those required under existing tank or waste programs. Unclear whether this applies to "waste" only. Is DEP willing to remove this section?	**Is DEP removing this section?**	
BB) 78.59a. Impoundment embankments	**No Statement**	Requirements expanded including soil sampling and compacting standards	**Will require quotes from firms providing professional services**	
CC) 78.59b. Freshwater impoundments	**No Statement**	Requirements expanded to include certification of proper construction, soil scientist certification, and pond closure in 9 months	**Will require quotes from firms providing professional services**	
DD) 78.61 & 78.62 Drill Cutting Disposal	**No Statement**	Increased restrictions and notice, including a blanket prohibition against disposal "within a floodplain," which could encompass thousands of feet beyond a body of water in flat areas of the Commonwealth	**Is DEP treating drill cuttings as waste? Requires analysis of # of well sites in affected areas**	

EE) 78.61 & 78.62 Stimulations Fluids	**No Statement**	Increased restrictions and notice, including a blanket prohibition against disposal "within a floodplain," which could encompass thousands of feet beyond a body of water in flat areas of the Commonwealth	**Requires analysis of # of well sites in affected areas**	
FF) All sections: 25 NEW Electronic submission requirements	**No Statement**	Applications, notifications, and submissions related to well permits, pre drill sampling, alternative practices, registration of existing impoundments or borrow areas, restoration reporting, production reporting, completions reporting, notice of disposal of drill cuttings, notice of reuse or filtering water, and more	**The dozen electronic submissions in the prior draft, from which PGCC sought relief, has more than doubled in the 2015 draft. Staffing and administrative costs unknown.**	

ATTACHMENT 5

Costs Associated With Area of Review Provisions

Expense (Not $0)

	Steps	Time (hrs)	Rate	Additions	Total	Comment	Notes
1	Permit new well	N/A	N/A	N/A	N/A	Already an expense to permit a new well for completion	
2	Initial Plat set up	2	$100	Y	$200	Rate reflects surveyor/engineer	*
3	Database Review	6	$50		$300	Rate will be greater if surveyor/engineer required	
4	Historical Research	3	$50	Y	$150	Rate and time are highly variable depending on map types and what historical date is available	**
5	Questionnaire	4	$50	$25	$225	Time includes time in office and to go to Post office for Certified Mail($)	***
6	Review Online map search	2	$50	Y	$100	(search for old wells) Assumed that free sources are used such as DEP website.	****
7	Update Plat from #4,#6	2	$100	Unknown	$200	Update could easily be more time based on research results of old well records and maps	
8	Field work	6	$50	Y	$300	Grid Search - Travel and Field time included, highly variable	*****
9	Update Plat w/#8	3	$100	Y	$300	Does not account for discrepancies or errors, highly variable process	******
10	Spreadsheet construction	4	$50	Unknown	$200	Requires a computer for electronic submittal	
11	Add Questionnaire #4 data	3	$50	Unknown	$150	Could lead to further field investigation and additions to AOR spreadsheet	
12	DEP Submittal	1	$50	Y	$50	Could have additional mail in maps and documents along with electronic submittal	
13	Monitoring Plan	2	$100		$200	Likely that surveyor/engineer will be involved in preparation and sign off	
14	Monitoring	13	$30	Unknown	$390	High risk wells will need continuous monitoring	
	Totals	42			$2,765	**Great many variables.**	

Time and rate is highly variable on the personnel and equipment available for construction - CAD, GIS etc....

Courthouse title records/maps might be needed adding more expense.

Additions in cost in "certified mail" assumed to be $6.25 per piece of certified mail to each surface owner (4 surface owners in Conceptual Model)

****Additional costs could be added if more expensive online mapping features are used. Some are thousands to buy. Accuracy is in an issue****

*****Site specific on time and expense, IF a surveyor or GPS tech is contracted out expect major increases in cost. Accuracy is an issue, what of wells near 500ft AOR outside?? GPS COST?!*****

******Requiring some level of technical experience to produce an appropriate Plat, could require outside contractor increasing cost and time******

ATTACHMENT 6,

Geologist Comments on DEP AOR Geometry Study

Comments on Area of Review Requirement
Section 78.52a of DEP's
Final Form Chapter 78 Regulations

March 18, 2016

A Southwest Pennsylvania conventional producer/operator always identifies current ***active*** and ***inactive*** wells within an area of potential development to access the economic worthiness of further development. These well categories are easily identified on PA DEP oil and gas topography maps because they have hardware that can be observed in the field. The available information associated with these wells via the PA DEP and Geological Survey (well permits plats, drilling and completion records, geophysical well logs, recent production, location on oil and gas topography maps) are incorporated into the geologic and engineering assessment of an area. In an area where industry activity predated regulatory control (permitting), a producer/operator must identify the historic information of active and inactive wells along with **orphaned**, **abandoned**, and **plugged** wells. The assessment of these well categories requires inquiry to utility companies and independent private producers for historic data that may be incomplete if it exists at all, and considered proprietary if it does. This information includes well card files, farm line maps, geophysical well logs, and production information. In most cases this data is not available at the said government agencies. The geologic, engineering, and economic assessment of any potential drilling prospect in SW PA incorporates all of the above data in identifying the potential productivity of an area. Geologic mapping identifies potential reservoirs that are modeled to determine estimated remaining reserves, production decline and proper spacing. Thus, the producer/operator is cognizant of the economics of proper development and has already performed its own area of review prior to drilling.

Concerning the proposed 1,000 foot AOR under Section 78.52a that a producer/operator must perform prior to the stimulation of a newly drilled conventional gas well, one must take into consideration the geology of the area of interest. The geology of SW PA conventional gas fields includes the "stacking" of several target reservoirs. From well to well there may be as few as one and up to five reservoirs in one single well that will be commingled to produce hydrocarbons. All such reservoirs were deposited in their own unique paleodepositional environment with differing dynamics. Depositional environments have inherent patterns and orientations that can place one reservoir with an NW-SE strike and another with a SE-NW strike. When multiple reservoirs, stacked at different depths, are mapped in an area of review, the occurrence of X reservoirs is not consistent from well to well. Apply this to a large area with greater than two potential reservoirs and the wells that are drilled will not conform to any uniform reservoir presence, orientation, or dictate any uniform thickness or qualities (porosity and permeability). Wells that are selected for drilling have gone through a vetting process

that considers the geology, engineering, and economics of each projected reservoir at each independent drill site. In many fields adjacent wells may not even share all of the same reservoir(s). Furthermore, each independent reservoir in each well does not have a uniform stimulation designed because of the unique characteristics noted (thickness, porosity, permeability) that are dynamic and vary from well to well.

The proposed 1,000 foot AOR for conventional wells does not take into account how dynamic and un-uniform the geology of conventional oil and gas fields are in SW PA. The cases that the DEP presents in support of the proposed AOR appear to assume a uniformity of a single reservoir case and would only be applicable to a field that has a single reservoir penetrated by the wells it contains. This is not realistic model for Upper Devonian oil and gas fields in Pennsylvania. The geometry study presented by the DEP better represents an AOR distance for an unconventional gas field where reservoir deposition and character are uniform. Furthermore, fracture propagation studies of Upper Devonian conventional oil and gas reservoirs in SW PA, most notably "Hydraulic Fracture Imaging Study" by Roger Willis & Jim Fontaine, Universal Well Services, 8/31/2005, are unanimously accepted by industry. These studies have apparently not been given consideration by the DEP in their AOR study.

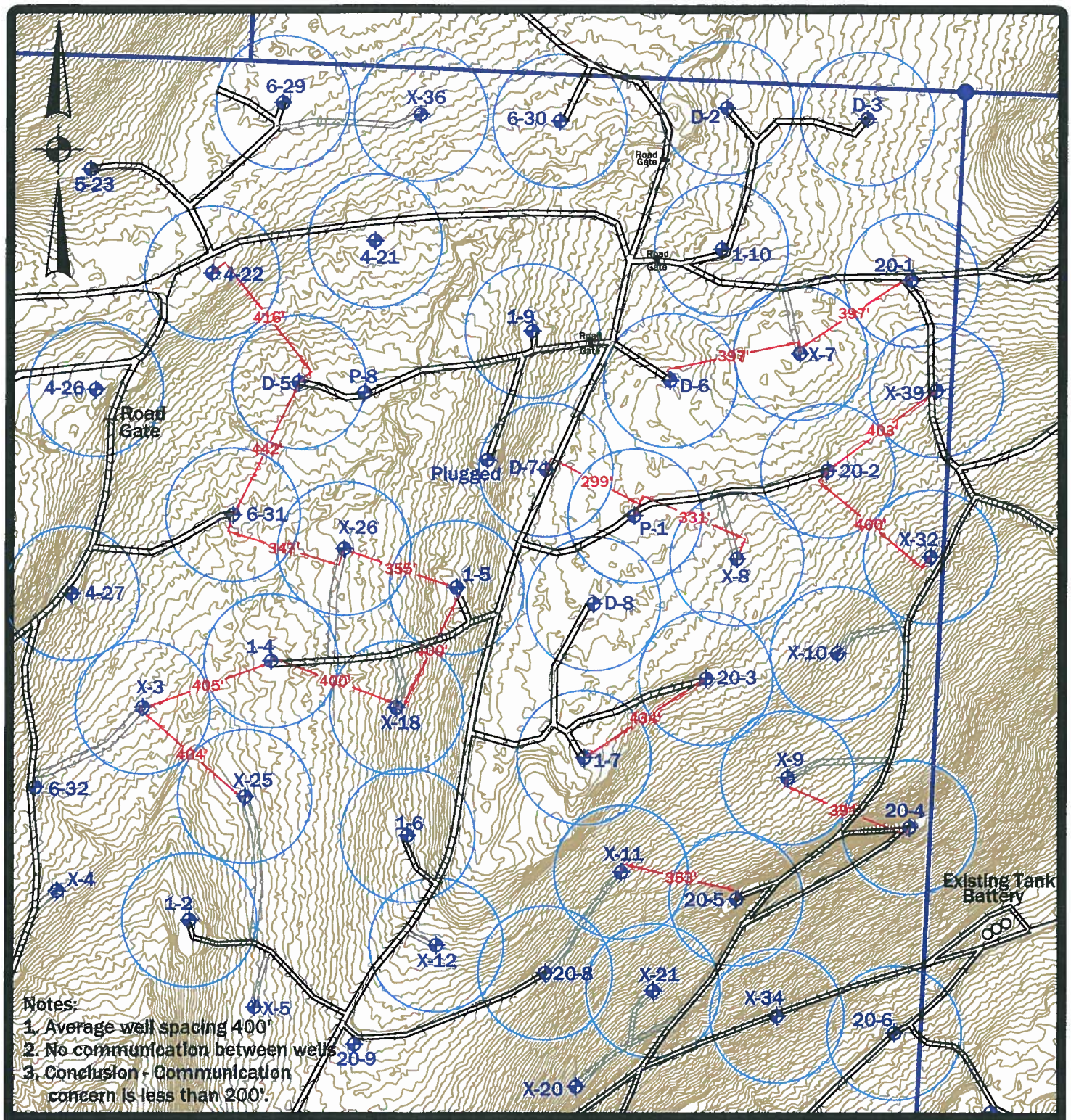
The work performed by Willis and Fontaine document the basic rock mechanics of the Upper Devonian formations in SW PA that include the fracture orientation and half lengths of reservoirs in wells that were stimulated. The DEP AOR study ignores that the Universal Well study documents that a hydraulic fracture will propagate perpendicular to the least principle stress in SW PA and that hydraulic fractures in formations deeper than 2,000 propagate vertically in the SW-NE direction of the well bore. This is taken into account by a producer/operator before placing a new well to be drilled amongst existing producing and/or inactive, orphaned, or plugged wells to avoid reservoir depletion that negatively impacts well economics. These very precautions also protect the stimulation of the new well from communicating with older abandoned and/or plugged wells.

The DEP AOR case studies found that the distance of communication between the two wells in each case to be less than 200 feet, which supports very similar findings in the Universal Well report. Producer/operators in SW PA understand this and avoid, as much as possible, stimulating a reservoir in a new well within 1,000 feet of a legacy well. In the case where reservoirs are stimulated less than 1,000 feet from a legacy well, there is little documented evidence of communication amongst the 60,000 plus conventional wells drilled since the advent of hydrofracturing.

In conclusion, there is no need for an AOR to be placed on conventional oil and gas wells because the producer/operator is already protecting the preconceived danger of communication by protecting their very on return on investment. A 500 foot or 1,000 foot AOR appears to be the result of statistical analysis of reported drilling and completion data with little consideration given to the complexity of the science beneath it.

ATTACHMENT 7

Oilfield Well Spacing Diagrams



Notes:
1. Average well spacing 400'
2. No communication between wells
3. Conclusion - Communication concern is less than 200'.

Scale: 1" = 400'

Date: 03/07/2016

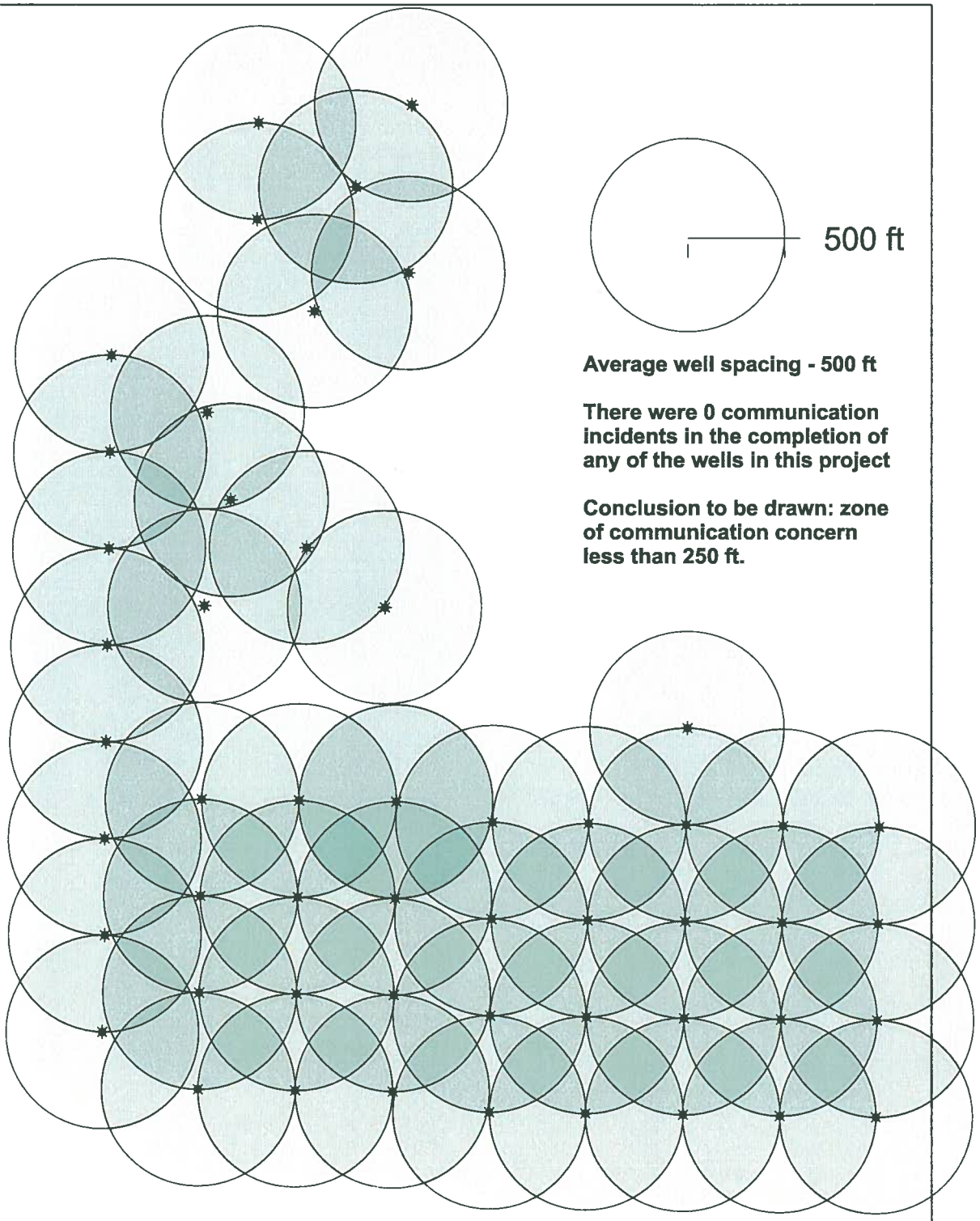
CAMERON Energy Company

Cameron Energy Company
450 Saybrook Road
Sheffield, PA 16347
Office: 814-968-3337
Fax: 814-968-3330

Exhibit

Conventional Well Field

Cherry Grove Township, Warren County
Pennsylvania



Average well spacing - 500 ft

There were 0 communication incidents in the completion of any of the wells in this project

Conclusion to be drawn: zone of communication concern less than 250 ft.

MINARD RUN OIL COMPANY

State: Pennsylvania

County: McKean

Township: Corydon

Date: 02/15/2016

Minard Run Oil Company

Conventional Oil Field in McKean County

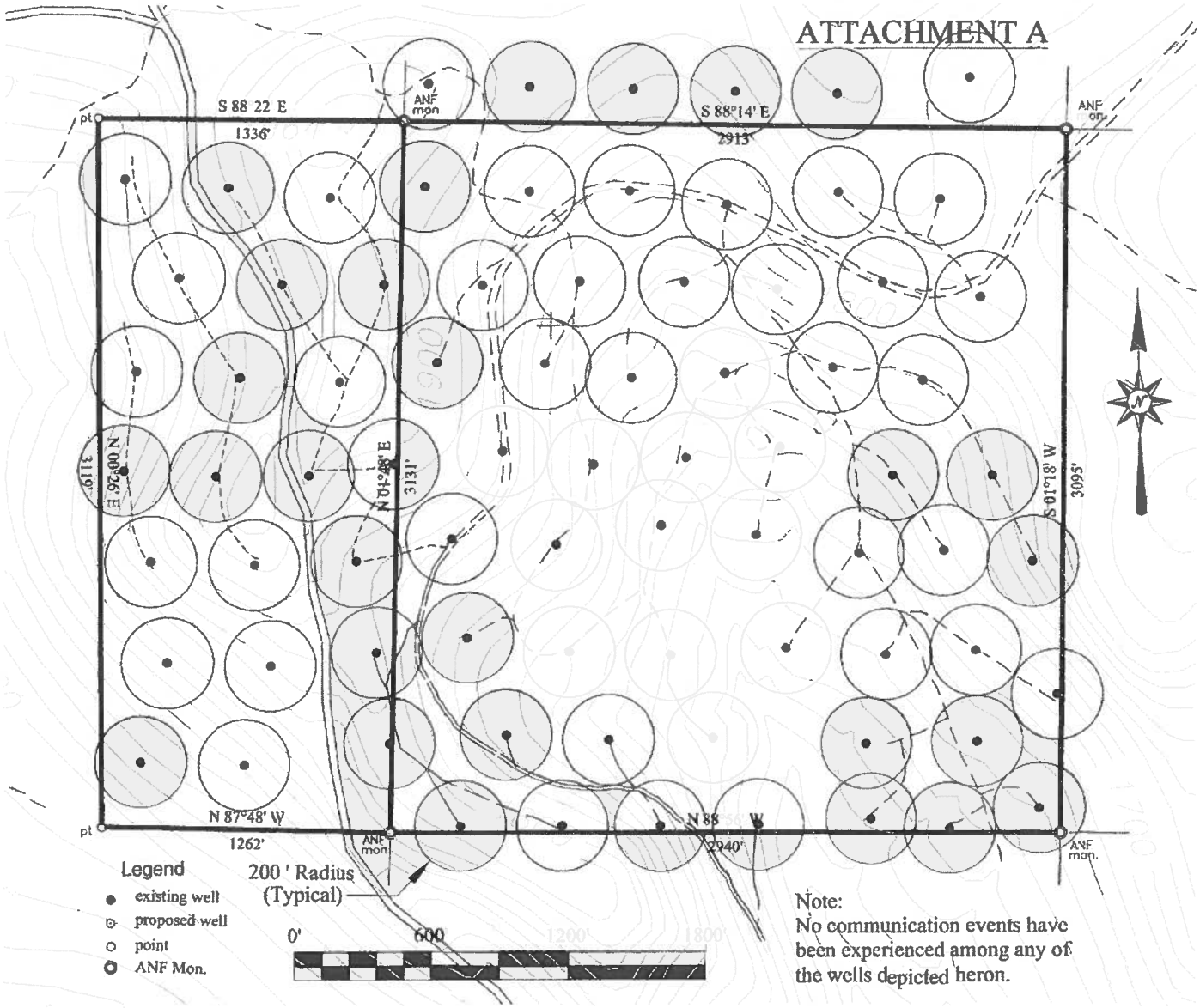
N

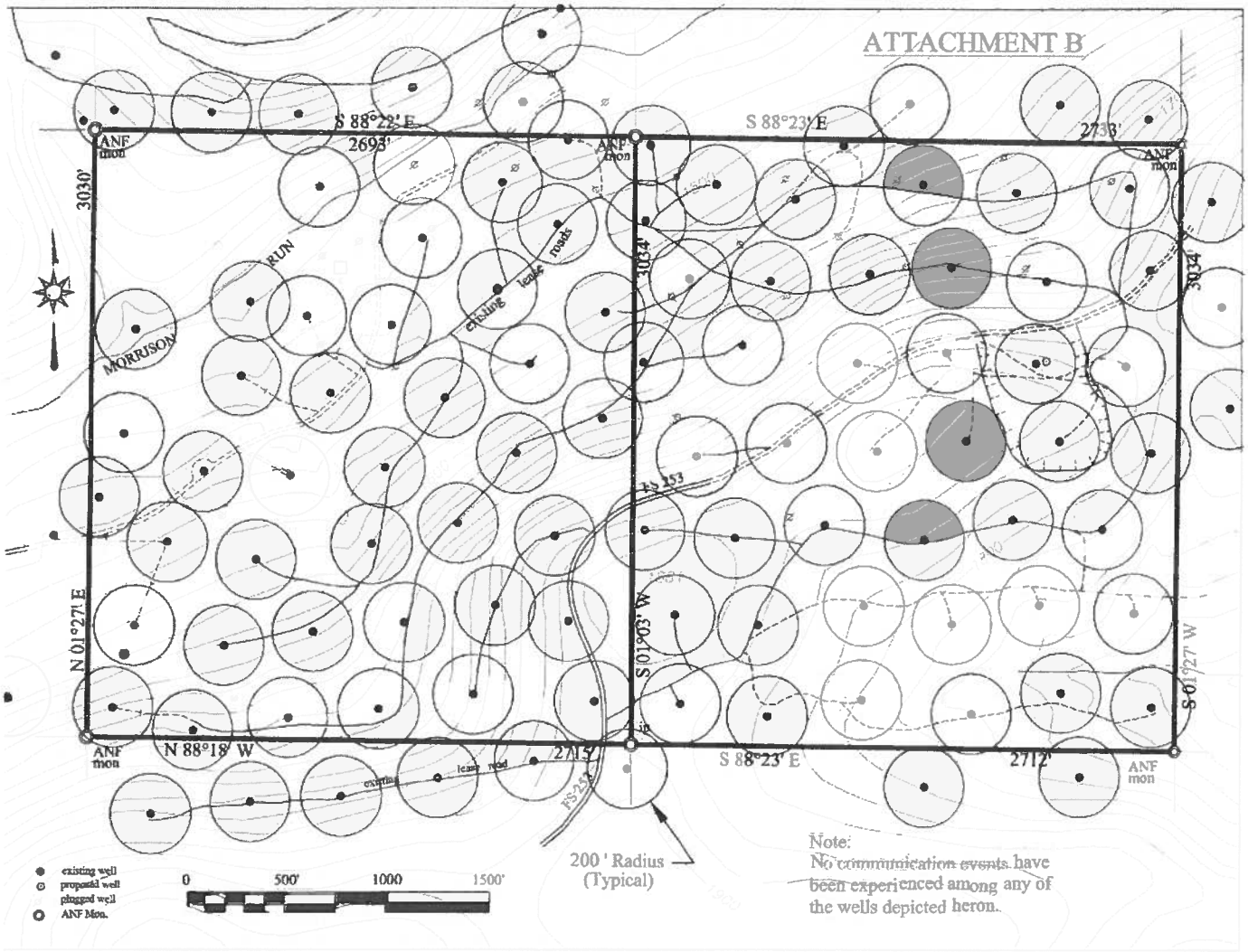
Scale

1 inch = 500 ft.

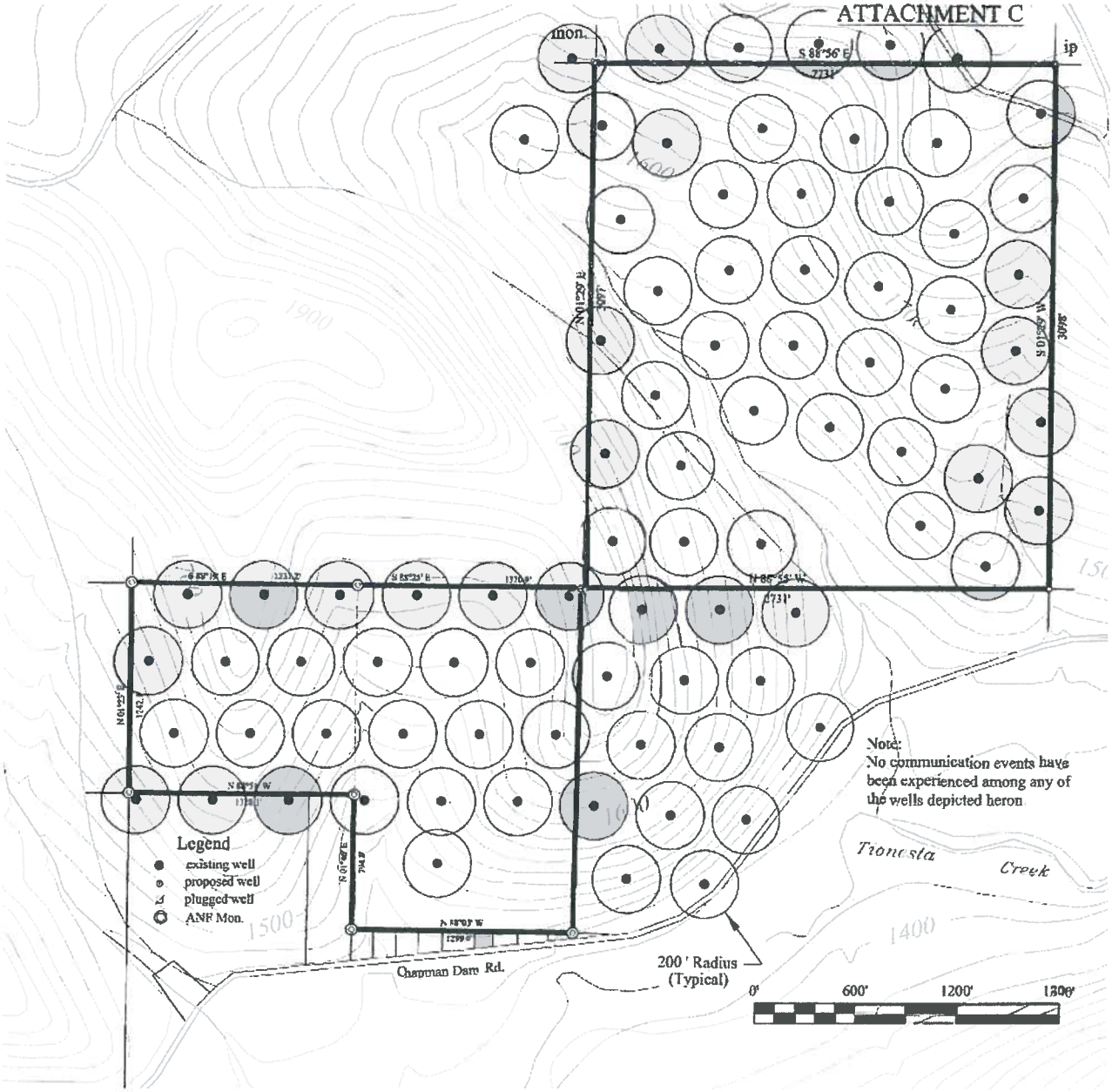
0 500 1,000 1,500 2,000 Feet

ATTACHMENT A




ATTACHMENT B
S 88°22' E
2693'
S 88°23' E
2738'
ANF mon
3030'
3034'
MORRISON
RUN
existing lease roads
N 01°27' E
S 01°03' W
S 01°27' W
N 88°18' W
2715'
S 88°23' E
2712'
existing lease road
FS253
200 ' Radius
(Typical)
Note:
No communication events have been experienced among any of the wells depicted heron.
existing well
proposed well
plugged well
ANF Mon.
0
500'
1000
1500'

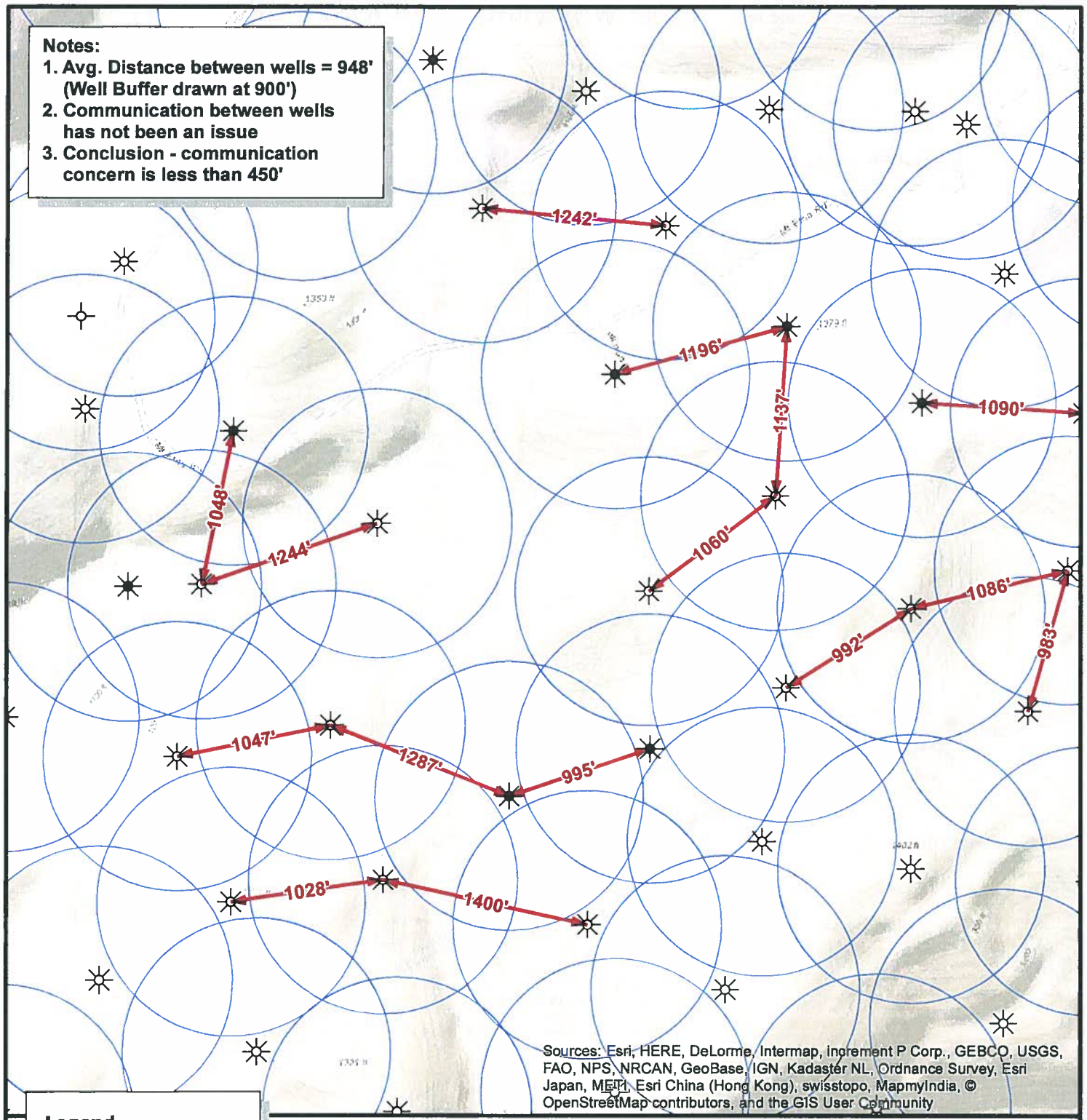
ATTACHMENT C



ATTACHMENT 8

Gas Well Spacing Diagrams

Exhibit



Legend

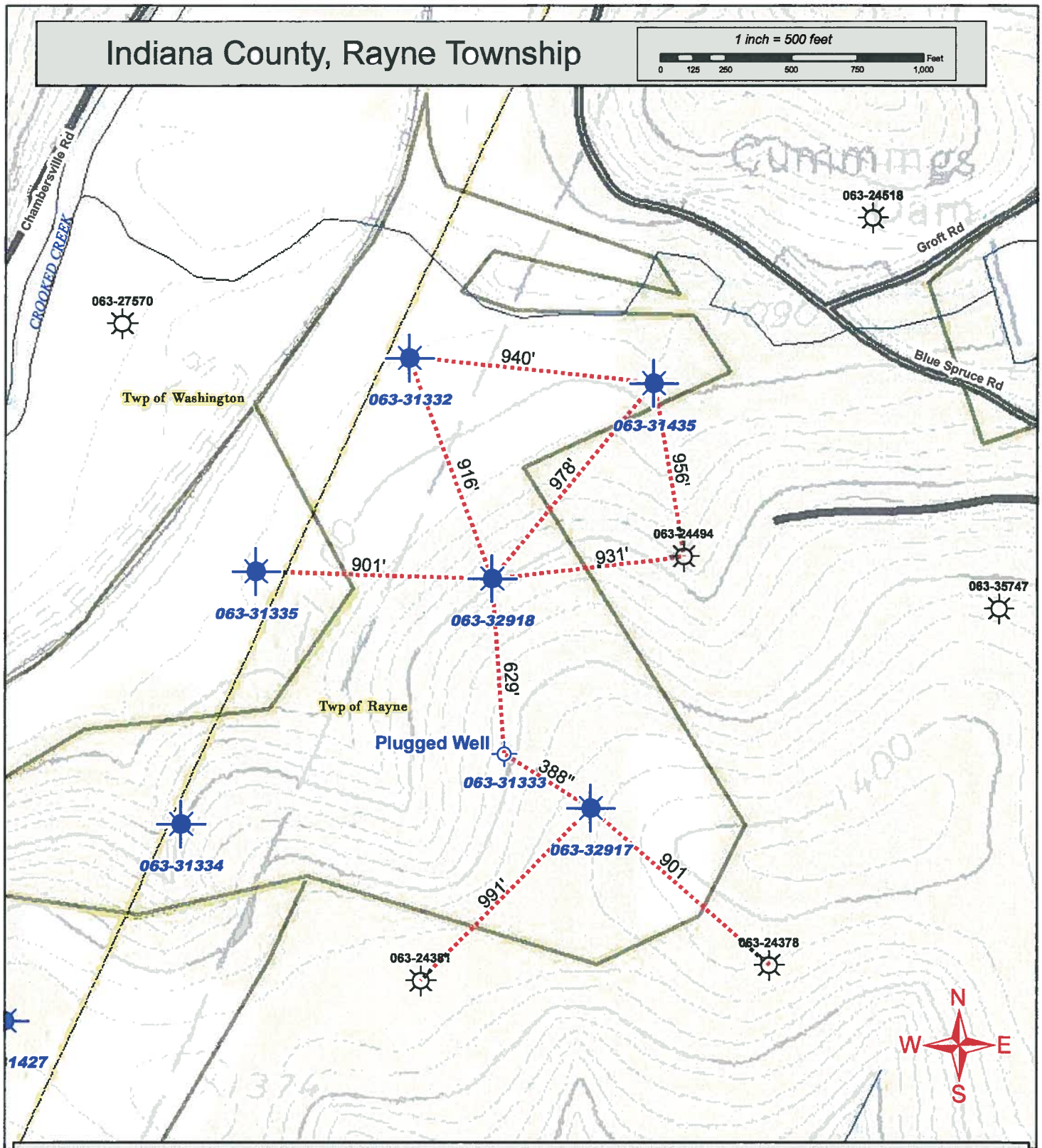
- OIL & GAS WELL
- ABANDONED DRY HOLE
- GAS WELL
- DIMENSION
- 900' SPACING

900 450 0 900 1,800 Feet

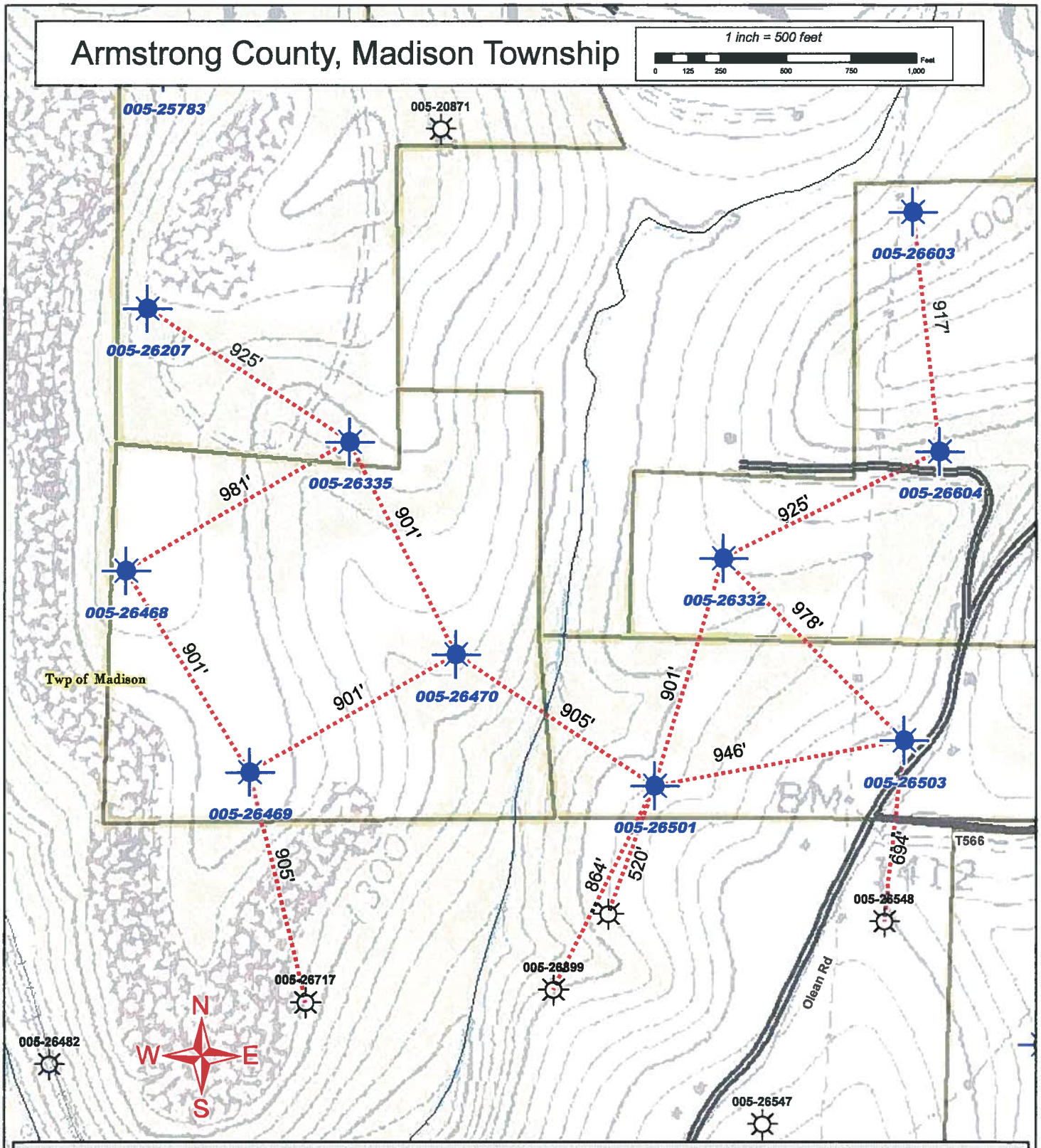
Date: 3/3/2016

1 inch = 900 feet

Conventional Oil Field
South Huntingdon Township,
Westmoreland County, Pennsylvania



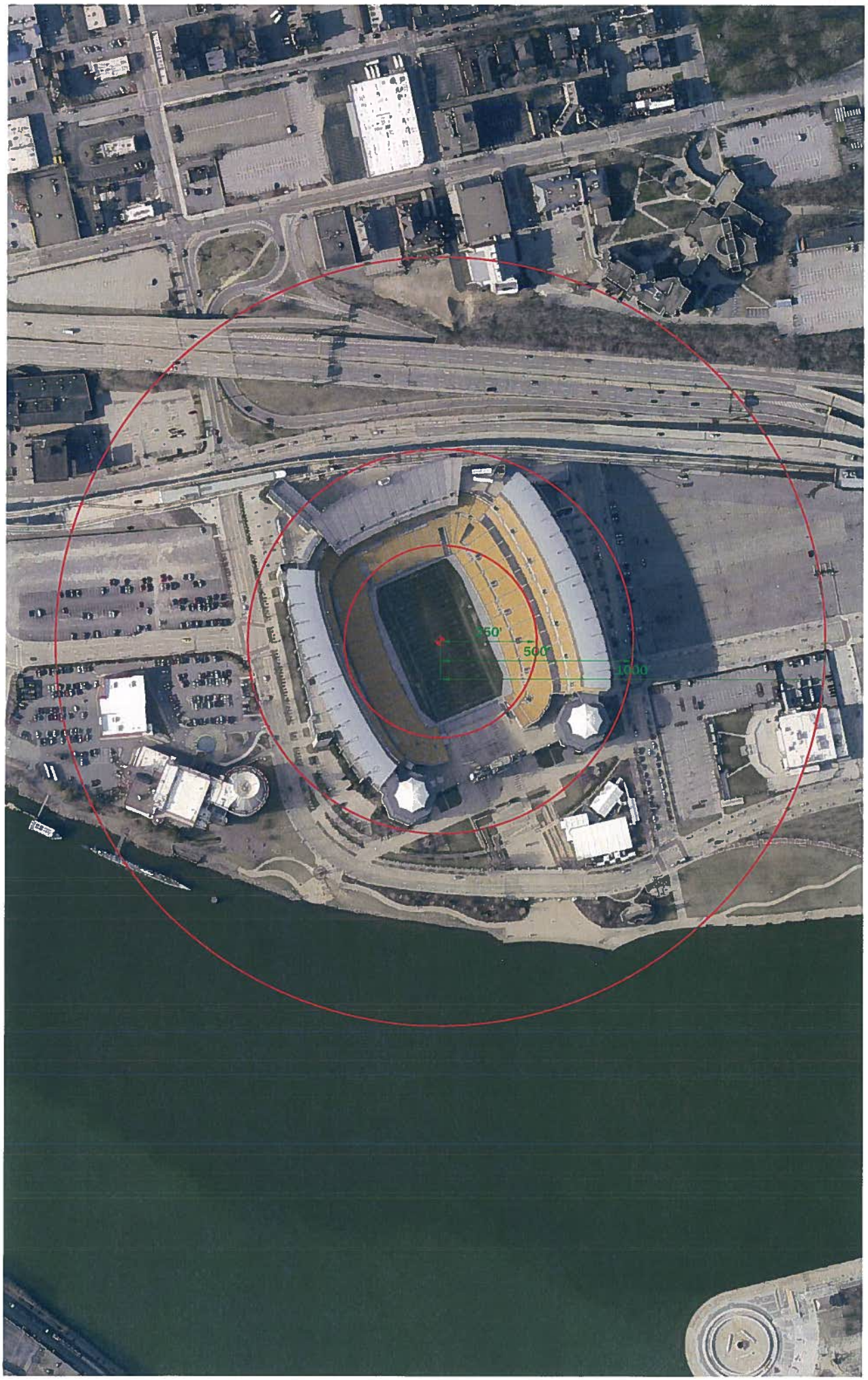
The distance between wells is approximately 900 linear feet. No evidence of communication between wells was observed during or after the hydraulic fracturing process, indicating that artificial fracture length does not exceed 450 linear feet.



The distance between wells is approximately 900 linear feet or less. No evidence of communication between wells was observed during or after the hydraulic fracturing process, indicating that artificial fracture length does not exceed 450 linear feet.

ATTACHMENT 9

Illustration of Area of Review Size Differences Between 500 ft and 1000 ft Radii, With Comparison to Heinz Field


250'
500'
1000'

ATTACHMENT 10

Site Restoration PCSM BMP Cost Estimates

Hanover
Engineering Associates Inc

May 12, 2015

Mr. David Clark
President
Pennsylvania Grade Crude Oil Coalition
P.O. Box 211
Warren, PA 16365

RE: Proposed Changes to PA Code Chapter 78
Engineering Feasibility Analysis – Chapter 102.8(g)

Dear Mr. Clark,

As you are aware, we have been requested to assist the Pennsylvania Grade Crude Oil Coalition (PGCC) in assessing the impact of the proposed changes to **Chapter 78: Oil and Gas Wells** of the Pennsylvania Code. Based upon our discussions, you are interested in the requirements identified in PA Code Chapter 102.8(g) involving Post Construction Stormwater Management (PCSM), and have requested our firm to prepare an outline of anticipated tasks, as well as preliminary engineering cost estimates associated with them.

Since the proposed rule changes are still in DRAFT form, we have limited our scope on this exercise specifically to Post Construction Stormwater Management requirements as we understand them to apply to non-conventional wells under the ESCGP-2 program of the Pennsylvania Department of Environmental Protection (PADEP). From an administrative perspective, we have also assumed that the associated permitting "process" will generally be handled in a similar fashion for conventional wells such as yours should the proposed rule changes go into effect.

In summary, 102.8(g) specifies the stormwater analysis and design criteria required by PADEP. These design criteria, as well as additional information regarding PCSM requirements and BMPs can be found in the **Pennsylvania Stormater Best Management Practices Manual (2006)**. The two significant design/analysis requirements of this section are:

1. BMPS must be installed to manage the net change in stormwater volume and water quality between predevelopment and postdevelopment conditions for storms up to and including the 2-year/24-hour storm event;

2. BMPs must be installed to ensure that the postdevelopment runoff rates do not exceed that of predevelopment conditions for the 2, 10, 50, and 100-year/24-hour storm events, OR will meet the release rate criteria specified in the applicable PADEP approved Act 167 plan, whichever is more restrictive.

It should be noted that the above requirements are associated with any changes in ground cover from predevelopment to postdevelopment, not necessarily only the addition of "impervious" cover.

We have also made the following technical assumptions to undertake this exercise, based upon preliminary information received from your organization:

252 Brodhead Road, Suite 100, Bethlehem, PA 18017 • 610.691.5644 • Fax 610.691.6968 • www.hanovereng.com

- Pads sizes of 60' x 120' (flat sites) or 48' x 144' (sloped sites) will be constructed;
- Approximate Access Road will be 24' x 400';
- Two (2) stormwater Best Management Practices (BMPs) will be required; one (1) for the access road and one (1) for the well pad;
- A combined structural volume of 4000 cubic feet (cf) will be required;
- Wetland/Watercourse evaluations and reporting costs are not included (a separate cost estimate can be provided if required, however generally speaking delineations and reporting will range from $4000-$5000 on a 5 acre site, not including any Chapter 105 permitting that may be needed.)
- Permit Fees are not included (typically dependent upon Limit of Disturbance);
- Typical Expenses (mileage, printing costs, etc.) are not included;

I. Estimated Engineering Costs

The requirements of Section 102.8(g) can be broken into five (5) phases, as follows with associated estimated engineering costs:

A. Topographic Survey (if required)

- Two (2) field days assumed to locate site features, collect topographic information of site, obtain driveway sight distances, etc. (Available LIDAR data will be used for balance of site topography, as permissible)
- Create Project baseplan.

Estimated Cost $3,200 - $3,600

B. Stormwater Infiltration Evaluation - Required to evaluate soil criteria, limiting zones, and soil permeability at specific BMP locations

- PA One Call;
- Preliminary site data collection;
- Survey Stakeout of probe locations;
- Field observation of probe excavation (2 days; 2 probes per BMP);
  Note: depending upon site characteristics, soil probes may not be required if surface infiltration is proposed and PADEP is agreeable
- Double-ring Infiltrometer Testing (1 day, 4 tests);
- Infiltration Report Preparation

Estimated Cost $6,200 - $6,800

C. BMP Design (Assumes 2 BMPs required) - Plan and report preparation to satisfy requirements of Section 102.8(g), includes preparation of site-specific Erosion and Sediment Pollution Control Plans (ESPC) which we assume will be required.

- Prepare ESPC & PCSM Design/Reports

- Prepare ESPC/PCSM Plans
- Prepare Act 14 Notifications
- Prepare PNDI Search (Assumes no hits)
- Prepare GIF/NOI and Checklist (Application)

Estimated Cost $17,400 - $18,800

D. **PCSM Construction Phase Services** - Professional oversight at critical stages of construction and associated reporting.

- Provide periodic site visits, photo document BMP construction, provide certification correspondence for structural BMPs

Estimated Cost $1,400 - $1,600

E. **PCSM Plan Recording & As-built Plan Preparation**

- Sign & Seal Post Construction Plans and record same at County Courthouse
- Record Operations and Maintenance Covenant
- Prepare as-built survey and plans of PCSM BMPs
- Record As-built Plans at County Courthouse

Estimated Cost $5,400 - $6,000

GRAND TOTAL OF ENGINEERING SERVICES: $33,600 - $38,800

II. Estimated BMP Construction Cost

In order to minimize overall site impact, cost, and long term operations and maintenance obligations associated with the required structural BMPs, we typically attempt to specify surface infiltration facilities (i.e. infiltration berms, etc.) for our clients in the industry. Based upon the assumption of 4000 cf of structural volume required, a reasonable assumption for the construction cost of such a facility would be **$4,000 - $6,000**. This is based upon the earthwork required to construct an approximate 1' high berm on an approximate 10% slope, for a total length of 150' that possesses a minimum infiltration rate (.5"/hr). Greater infiltration rates will yield smaller required facilities, generally speaking. In contrast, a more complex BMP, such as a subsurface stone infiltration facility with inlet/outlet control structure will be less cost effective at approximately **$13,000** to **$15,000**.

It should be noted that this cost can vary significantly depending on site constraints and the specific design and construction techniques required. It also does not include long term Operations and Maintenance obligations for the facilities, which are required.

III. Estimated Design & Approval Timelines

- Design package development & submission to PADEP: 3-4 weeks
- Expedited Permit Review: 2 weeks*Note: not eligible in special protection (HQ/EV) watersheds
- Non-expedited review: 60 calendar days

We would recommend that all of the above costs be used as a planning tool only, since every site is unique and should be evaluated as such. However, based upon our extensive experience within the Oil & Gas industry, economies of scale can be developed, and costs refined as design standards are created to fit a particular client's needs. We have already developed many sets of standards for our clients, and they allow an "assembly line" approach to design development of the various well sites. Additionally, developing the designs for several wells, preferably geographically close to one another concurrently will also help to reduce overall design costs associated with the proposed requirements.

We would be more than willing to discuss any of the above with you and your colleagues at your convenience. We understand that navigating through the various requirements of the many agencies that oversee your industry can be a challenging task, however we have an outstanding working relationship with PADEP that allows us to provide our clients with the most cost effective, and timely design solutions.

If you have any questions or would like additional information about this project, please do not hesitate to contact the undersigned.

Respectfully,

HANOVER ENGINEERING ASSOCIATES, INC.

Phillip C. Malitsch, PE

Pcm/pcm
C:\Users\HEA Staff\Desktop\20150507_ConventionalWellPCSM.docx

Moody
and Associates, Inc.
www.moody-s.com

Ground Water and Environmental Professionals – Since 1891

April 30, 2015

Mr. David Clark
President
PGCC
PO Box 211
Warren, PA 16365

RE: Cost Estimated for Proposed Changes to Chapter 78 Regulations in Regards to Chapter 102.8(g)

Dear Mr. Clark:

Moody and Associates, Inc. (Moody) was contacted to estimate the cost to complete the scope of work related to the proposed changes to Chapter 78, as it pertains to Chapter 102.8 (g). Moody, along with the assistance of Deiss and Halmi Engineering, have come up with the following scope of work and cost estimates. The scope and cost estimates are based on the following assumptions provided by PGCC:

- A total of 27,200 square feet of impervious surface (includes a 60' x 120' well pad and a 50' wide road approximately 400' long).
- Three to six soil test pits will be evaluated visually and with double-ring infiltrometer tests (the owner will be responsible for providing equipment and an operator to excavate the test pits and provide a supply of water for testing).
- Permanent structural BMPs are assumed to be needed for the impervious area.
- An E&S Plan is not included in the scope of work, since it was previously required.
- Wetland determination, ecological screening and environmental permitting that may be required has not been included, since it was previously required.
- The site is not located within a special protection watershed.
- Detailed topographic survey of the project site is available.

Scope and Costs:

- Engineering services to prepare PCSM Plan to meet 102.8(g) requirements: $10,000 - $15,000.
- Engineering services to prepare NPDES Permit application, if required: $2,000 - $5,000.
- Construction cost for storm water BMPs only: $10,000 - $50,000.
- Detailed topographic survey: $2,000 - $4,000 (if not provided).

MEADVILLE, PA 11548 Cotton Road • Meadville, PA 16335 • Phone: 814.724.4970 • Fax: 814.724.4973 • 800.836.5040
HOUSTON, PA 199 Johnson Road, Building 2, Suite 101 • Houston, PA 15342 • Phone: 724.746.5200 • Fax: 724.746.5603 • 866.336.0000
WAVERLY, NY 685 Broad Street Extension, Suite 1 • Waverly, NY 14892 • Phone: 607.565.8800 • Fax: 607.565.8805 • 877.602.3120

- Wetland determination, ecological screening and environmental permitting: $2,000 - $10,000 (dependent on location, amount of disturbance and type of permit needed).

Total Costs: $22,000 - $84,000

Timeline:

- Time frame for PCSM design: 4 - 8 weeks.
- Time frame for DEP review of application: Varies depending on DEP workload (typically 2 - 6 months).

Respectfully,
MOODY AND ASSOCIATES, INC.

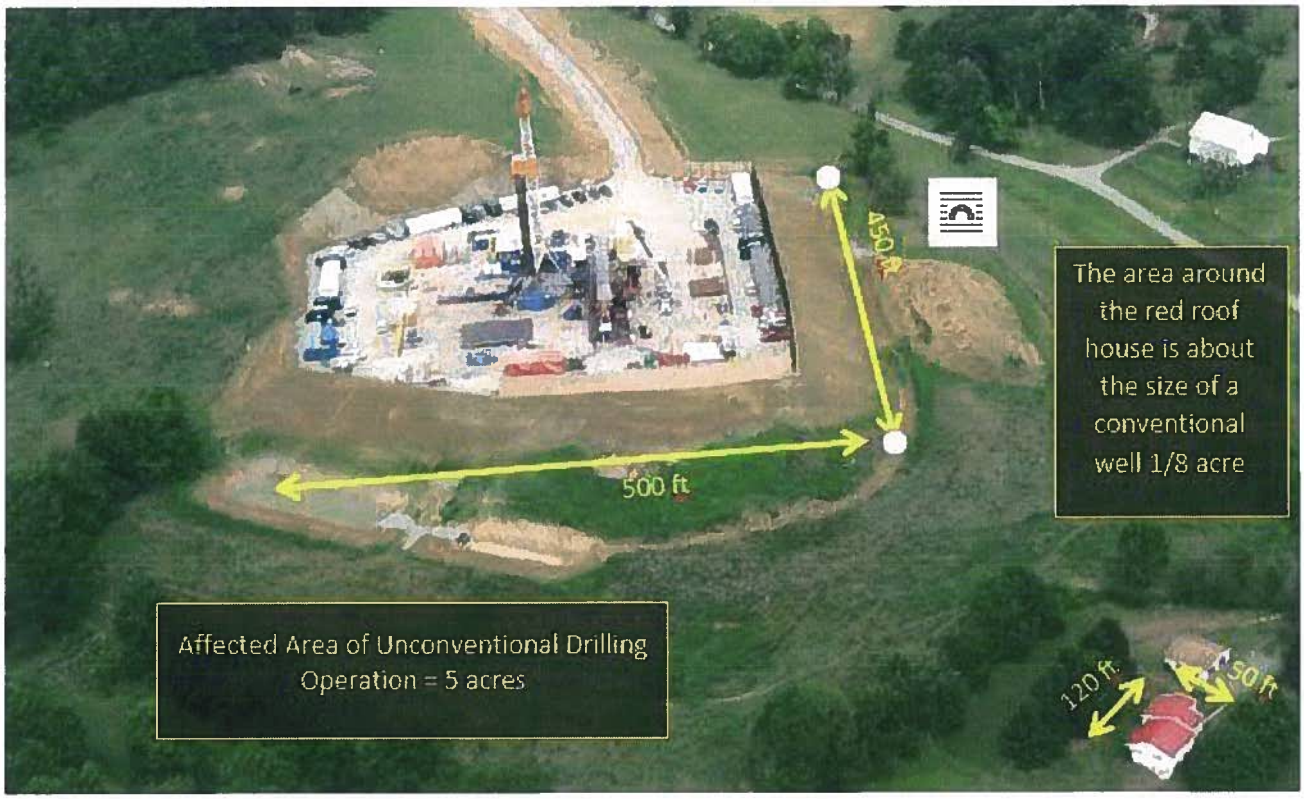
Mark B. Miller, P.G.
Senior Associate

MBM/mbm

ATTACHMENT 11

Photographs Comparing Footprints of Unconventional Versus Conventional Drilling Operations

Unconventional Drilling Operation



Conventional Drilling Operation

ATTACHMENT 12

Representative Photograph Illustrating Extent of Wetlands Surrounding Well

ATTACHMENT 13

Representative Photographs of Well Sites to be Restored

ATTACHMENT 14

Act 2 Oil Spill Cleanup Costs

Act 2 Oil spill cleanup of 60 barrel spill in January of 2014

	As of 10/27/2014	Hours	Avg Rate/hr	Total
In House Labor				$ 31,896.25
In House Equipment Used (see tab)				
	Mini Excavator	3	$ 65.00	$ 195.00
	Ditch Pumps	2	$ 150.00	$ 300.00
	Excavator	4.5	$ 85.00	$ 382.50
	Light Dump	2	$ 70.00	$ 140.00
	Heavy Dump	6	$ 85.00	$ 510.00
	Semi Truck	4	$ 115.00	$ 460.00
Total Invoiced to date from Vendors for Clean up				$ 160,994.10
	includes $132,360 for rental of 72 containers and disposal of contents at landfill			
Grand Total				$ 194,877.85

[redacted]

From: [redacted]
Sent: Monday, March 21, 2016 12:16 PM
To: [redacted]
Subject: FW: Act 2 cleanup

From: [redacted]
Sent: Monday, March 21, 2016 11:29 AM
To: [redacted]
Subject: RE: Act 2 cleanup

[redacted]

Sorry for the delay but I was on vacation last week and did not have access to the file on this spill.

The spill was reported on March 7, 2014 and happened when we were pressure testing well casing. The discharge was on a well pad and nearby lease road/ditch and consisted of 170 gallons of produced fluid (brine). The area affected was determined to be 385 feet by 55 feet. We removed less than 20 tons of soil.

All in cost for cleanup including internal & external was $23,000. The vast majority was the testing and preparation of the report to meet the DEP's satisfaction.

Let me know if you need anything more.

[redacted]

From: [redacted]
Sent: Wednesday, March 16, 2016 9:41 PM
To: [redacted]
Subject: Act 2 cleanup

[redacted]
I just received [redacted] Act 2 costs—and it turns out that is the one I have.
Can you please resend yours to me.
Sorry.
[redacted]

ATTACHMENT 15

Photographs Depicting Typical Proximity of Wells


DRAKE

ATTACHMENT 16

Sample PPC Plans

Spill and Pollution Prevention, and Countermeasure Plan

Facility Owner:

Contact Name:

Updated by:

Primary Contact:

Secondary Contact:

Alternate Contact:

Note: All contacts have the authority to implement any action necessary to respond to a spill.

Section 1. Operations and Facilities Description

Daily Operations:

1. Drilling new wells.
2. Servicing new, production, and wells not currently in service.
3. Hydro-Fracturing new wells.
4. Laying pipe for natural gas and crude oil transportation.
5. Site Locations Preparation.
    A. Reclaiming or construction of new shale / stone roads to wells.
    B. Clearing and grubbing locations.
6. Reclamation of disturbed earth after locations and roads have been reclaimed or built.

Fixed Storage:

All production locations have or share a fixed tank battery containing crude oil and brine.

Non-Fixed Storage:

Vacuum truck and portable tanks.

Section 2. Oil Spill History

No significant spills.

Section 3. Spill Prevention Measures

1. Each tank battery has a pond or dike system with a capacity greater than the capacity of the tanks at the battery. Current / new designs are at two and one half the capacity of the battery.

2. All tank batteries and portable equipment are inspected before use or daily before commencement of pumping. Extensive inspections are performed during an annual review of property and equipment.

3. During the drilling / hydro-fracturing process, each well will have a sump impervious to polluting substances.

4. All employees have unrestricted access to the "spill shelf" contents at the

. Current contact information is updated as needed.

5. On a monthly basis, the inventory of materials at the "spill shelves" used to contain a spill is checked and re-stocked as necessary.

Section 4. Spill Response

Containing a crude oil spill resulting from daily operations, a leak, or malicious activity must be confined quickly to prevent damage to the environment.

Persons encountering a spill are to take all action necessary to eliminate the source and to contain and control the spilled material. This is the first priority and the action shall include temporary repairs, plugs, dikes and the like. If a waterway is threatened the priority is to continue the temporary measures to avoid damage to the waterway. At the first opportunity (when it is safe to interrupt the temporary measures) notify the office and if after hours notify , or per the Energy Emergency Phone List. If that contact is unsuccessful contact

Messages are to be delivered up the chain of command to Operations Manager with ultimate communication to .

All company employees are authorized to contact any employee on the Emergency Phone List in order to enlist the help necessary to respond to a spill situation. No employee will be penalized for summoning "too much" help.

maintains "spill shelves", one each at the shop and the , shed, the shop, and the generator station. These shelves contain absorbent pads, booms and flakes. These materials are within thirty minutes of all of facilities.

Backhoes, excavators and shovels (as necessary) shall be used to dig diversion ditches, form dams and catch basins in order to contain the spilled material. Absorbent material shall be deployed especially in an effort to protect waterways. If oil reaches a waterway deploy booms immediately at strategic downstream locations in an effort to check and contain the flow. Use impoundment dikes and siphons as necessary.

The vacuum truck shall be used as necessary to collect spilled material.

Notifications to the Department of Environmental Protection shall be made within two hours.

Notifications:

1. Commonwealth of Pennsylvania
   Department of Environmental Protection
   Oil and Gas Office, Northwest Region
   230 Chestnut Street
   Meadville, PA 16335
   814-332-6860
   (After hours: 800-373-3398)

2. Commonwealth of Pennsylvania
   Department of Environmental Protection
   Oil and Gas Office, Warren Office
   814-723-3273

3. Commonwealth of Pennsylvania
   Department of Environmental Protection
   Oil and Gas Office, Knox Office
   814-797-1191

4. Warren County Emergency Management
   300 Hospital Drive
   Warren, PA 16365
   814-723-7553
   814-723-8478

5. VFD

6. VFD

Containment equipment.

All necessary equipment shall be mobilized to address the spill. No employee will be penalized for exercising discretion to utilize equipment. has at its disposal bulldozers, excavators, backhoes, dump trucks, vacuum trucks, assorted A.T.V.'s, and tractors.

Outside contractors.

has standing relationships with:

Commercial Disposal contractors.

EAP Industries, Inc.
814-827-9902

Weavertown Environmental Group
800-746-4850

James Cerra
814-723-1357

Structural Containment Methods

Structural containment methods should be used on an as needed basis at an appropriate scale during a spill.

1. Containment diking

2. Curbing, on a small scale basis

3. Collection basins, retention ponds

4. Weirs, booms, or other barriers

Section 5. Drilling

utilizes independent contractors to meet its drilling needs. works with its contractor(s) to insure proper operations.

Contractors will employ dusting techniques when permissible. Uncontaminated drill cuttings and fresh tophole water are to be contained in a lined pit if dusting is not permissible. If significant quantities of fresh water are encountered it will be contained in a lined pit and discharged in a controlled manner to avoid erosion and sedimentation issues. Two feet of freeboard is to be maintained.

Section 6. Well Servicing

Portable tanks or lined pits are to be used if fluids are expected to be encountered. Two feet of freeboard is to be maintained.

Section 7. Hydrofracturing and Plugging

Portable tanks and lined pits will be used to contain fluids. Well flow-back, if contained in a pit, will be with a minimum 20 mil liner. Two feet of freeboard will be maintained.

Reference:

1. Oil Spill Prevention, Preparedness & Response, U.S. EPA Emergency Response Program.

2. Storm Water Management Fact Sheet, Spill Prevention Planning, U.S. EPA

3. Federal Regulations, Title 40, Protection of the Environment

4. Sample SPCC Plan, Maryland Department of Natural Resources

Emergency Response Quick Reference

Each of the items in this guide is described in detail in the following pages. See the Table of Contents for specific information.

In the event of a discharge at a [redacted] facility, the following is a quick reference to emergency response. When safe to do so, the discoverer of a discharge shall perform the following:

See Discharge Notification Flowchart

1) Take initial spill response action
   a. Eliminate sources of ignition
   b. Isolate the source of the discharge, minimize further flow
      i. Place sorbent material or other barriers in the path of the discharge (e.g., sand bags), or constructing earthen berms or trenches.

2) Make internal notifications
   a. Field Operations Manager

3) Make external notifications
   See Table 1 for facility specific emergency contact information.

Table 1 - Federal Agency Emergency Contact

Federal Agencies			
EPA National Response Center	800.424.8802	Discharge reaching navigable waters	Immediately(verbal)
EPA Region # 3 Phone:	215.814.5000	Discharge of 1000 gallons or more; or second discharge of 42 gallons or more over a 12 month period	Immediately(verbal) and written within 60 days (see **Section 3.2** of this plan)
Address:	1650 Arch Street Philadelphia, Pennsylvania 19103		

4) Activate [redacted] resources as necessary
   See Table 7 for Emergency Contractors for each facility.

5) Monitor and control the containment and clean-up effort

More information on each of the items listed above; please reference this plan in its entirety.

Description of Operations

The facilities described herein are oil and/or gas storage and production facilities. Production consists of crude oil, natural gas, condensate, produced water (brine), or any combination of these daily.

Production from these facilities is treated through a heater treater or separator where any oil, water and gas are separated.

Any water produced at these facilities is transferred via truck to an offsite disposal facility or via pipeline to a water treatment plant owned and operated by [redacted]

There is no oil production at any NCL Natural Resources Facilities

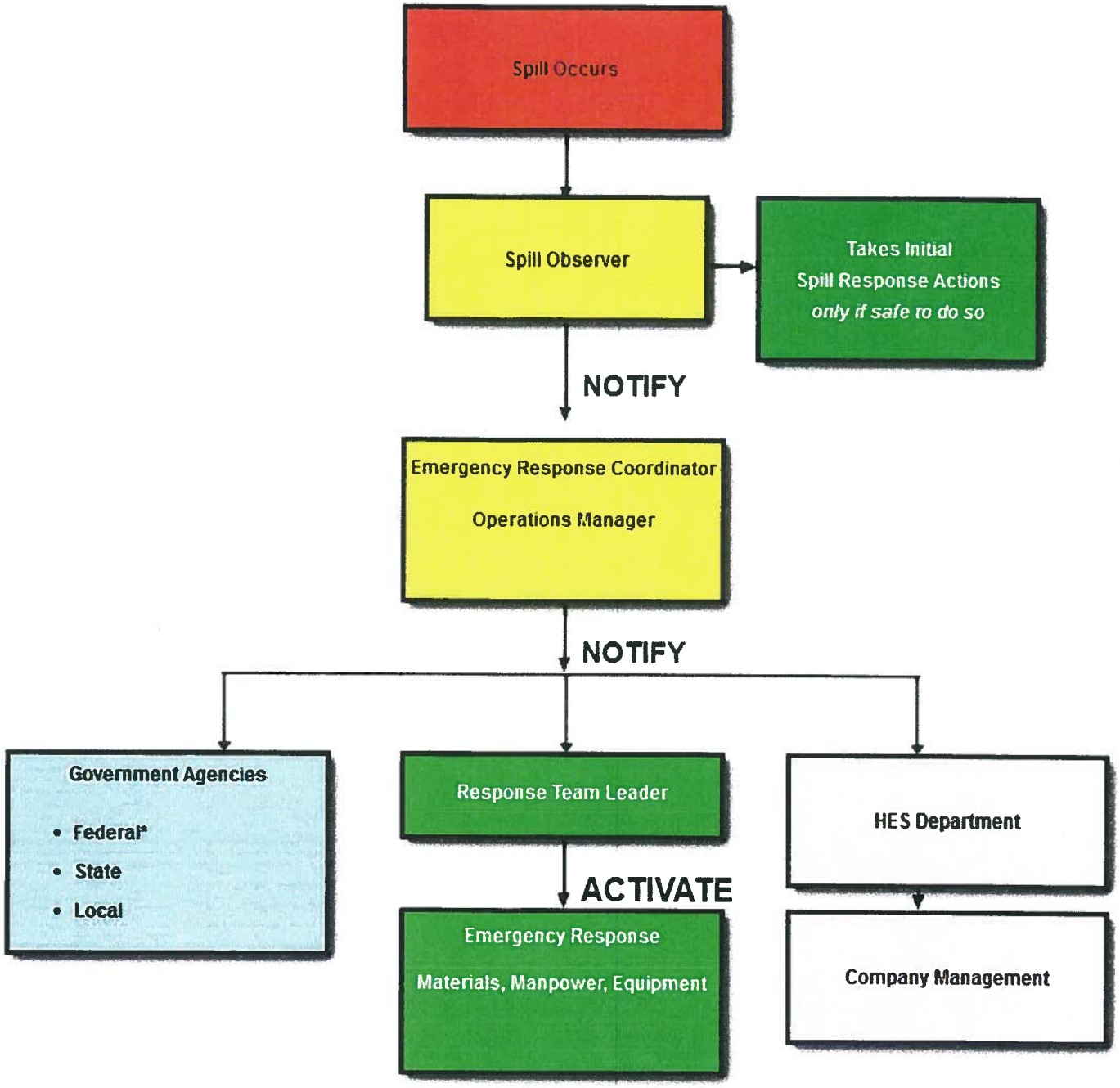
The purpose of this Preparedness, Prevention, and Contingency (PPC) Plan is to improve and preserve the purity of the Waters of the Commonwealth by prompt and adequate response to all emergencies and accidental spills of polluting substances for the protection of public health, animal, aquatic life, and for recreation.

[redacted] prevents accidental releases by training personnel in the proper and safe operation and maintenance of the facility and by designing and constructing facilities with appropriate safety features included. However, should a release occur, facility personnel will respond to control and contain the release.

[redacted]

Company Emergency Response and Notification Protocol

In the event of a discharge that threatens to result in an emergency condition, facility field personnel must verbally notify the Pennsylvania Department of Environmental Protection - Bureau of Oil and Gas Management no later than within one (1) hour of the discovery of the discharge. An emergency condition is any condition that could reasonably be expected to endanger the health and safety of the public, cause significant adverse impact to the water, land, or air environment or cause severe damage to property.



***National Response Center must be notified immediately when spill reaches "waters of the US" or appears certain to reach "waters of the US".**

Worst Case Scenario

All personnel shall know the location and proper use of emergency equipment including fire extinguishers, absorbent booms and pads.

A discharge at a [redacted] facility would typically be caused by atmospheric tank rupture or flowline rupture. In the event of a single tank rupture, secondary containment would contain any discharge. Secondary containment would also suffice if a flowline (located within secondary containment) rupture occurred.

Discharge Notification Procedure

The following is a summary of actions that must be taken in the event of a discharge. It summarizes the distribution of responsibilities among individuals and describes procedures to follow in the event of a discharge.

[redacted] performs all routine maintenance at its own initiative and has located and corrected several potential future problems by operating in this fashion. The documentation of spills and clean-up activities is the responsibility of the response coordinator.

If a second rupture was to occur or secondary containment was found to be insuffieient, [redacted], the Fields Operations Manager, [redacted]s personnel, or Contractors field personnel shall be responsible for the following

Shut-Off Ignition Sources

Field personnel must shut off all ignition sources, including motors, electrical circuits, and open flames.

Stop Oil Flow

Personnel should determine the source of the discharge, and if safe to do so, immediately shut off the source of the discharge in accordance with OSHA health and safety requirements.

All personnel shall know the location of the emergency shut-off valves if there are any.

Stop the Spread of Oil and Call the Field Operations Manager

Field personnel shall use the resources available at the facility to stop the spilled material from spreading. Measures that may be implemented, depending on the location and size of the discharge, include placing sorbent material or other barriers in the path of the discharge (e.g., sand bags), or constructing earthen berms or trenches.

In the event of a significant discharge, field personnel must immediately contact the Field Operations Manager, who may obtain assistance from authorized [redacted] contractors in order to effectively direct the response and cleanup activities. See **Table 6** for a list of additional contacts and contractors.

Gather Spill Information

The Field Operations Manager will ensure that notifications have been made to the appropriate authorities. The Field Operations Manager may ask for assistance in gathering the spill information.

- Reporter's name and telephone number
- Exact location of the spill
- Date and time of spill discovery
- Source of spill
- Material spilled (e.g. oil or produced water containing a reportable quantity of oil)
- Total volume spilled and total volume reaching or threatening navigable waters or adjoining shorelines
- Weather conditions
- Whether an evacuation may be needed
- Spill impacts (injuries, damage, environmental media, (e.g. air, waterways, groundwater))
- Names of individuals and/or organizations who have also been contact

Notify Agencies Verbally

It is important to immediately contact the Field Operations Manager so that timely notifications can be made. If the Field Operations Manager is not available, or the Field Operations Manager requests it, field personnel must designate one person to begin notification. **Table 1** of this Plan describes the required notifications to government agencies. The Response Coordinator must also ensure that written notifications, if needed, are submitted to the appropriate agencies.

This PPC Plan provides condiserable detail of [redacted]s response capability including notification procedures, response actions, clean-up capabilities (including contractor capabilities), response equipment, and response team organization. A copy of this Plan is maintained at [redacted]s offices.

Pollution Incident Response

Initial response actions are those taken by local personnel immediately upon becoming aware of a discharge or emergency incident. Timely implementation of these initial steps is of the utmost importance because they can greatly affect the overall response operation.

The first priority in any discharge event is safety. Only attempt spill containment or cleanup activities if it can be done safely. A spill containment and cleanup activity will never take precedence over the safety of personnel.

It is important to note that **these actions are intended only as guidelines.** The appropriate response to a particular incident may vary depending on the nature and severity of the incident and on other factors that are not readily addressed. Note that, **without exception, personnel and public safety is first priority.**

The first [redacted]person on scene will function as the person-in-charge until relieved by an authorized supervisor. Transfer of command will take place as more senior management respond to the incident.

[redacted]has sufficient equipment and personnel to respond to most, if not all anticipated discharge events. If a discharge event is beyond the response capabilities of [redacted]then subcontractors may be called upon for additional equipment, personnel or expertise.

[redacted]will contact the contractors listed in **Table 6** in the event that company personnel are unable to adequately respond to an emergency. Each contractor and their respective services are listed in **Table 6**.

Pollution Prevention Measures

Secondary Containment

Each of the [redacted]facilities has secondary containment provided by earthen berms. Each site berm will be installed around each facility. The site berm will be made of material impervious to oil and function as the main secondary containment.

Each site berm is constructed to provide secondary containment to the entire facility with sufficient capacity to contain the largest tank while maintaining adequate freeboard for precipitation.

Personnel Training

In accordance with 40 CFR 112.7(f), [redacted]personnel training will include, at a minimum:

- The operation and maintenance of equipment to prevent the discharge of oil.
- Discharge procedure protocol.
- Applicable pollution control laws, rules, and regulations
- General facility operations.
- The contents of this PPC plan.

MSDS

Material Safety Data Sheets (MSDS) are provided in **Appendix "A"** of this PPC plan.

Preventative Maintenance and Inspection

The program for a regular inspection of all storage tanks and related production and transfer equipment follows the American Petroleum Institute's Recommended Practice for Setting Maintenance, Inspection, Operation, and Repair of Tanks in Production Service (API RP 12R1, Fifth Edition, August 1997).

Each container and related production and transfer equipment is inspected at least annually by field operation personnel as described in this Plan or by an outside third party. The annual inspection is aimed at identifying signs of deterioration and

maintenance needs, including the foundation and support of each container. Any leak from tank seams, gaskets, rivets, and bolts is promptly corrected.

The inspection consists of two parts:

1. A visual inspection for deterioration, discharges, corrosion, required maintenance, etc. In the event a visual inspection indicates conditions that warrant testing then;
2. A visual inspection will be performed at a time when the tank is substantially full of fluid to constitute a hydrostatic test.

A summary of the types of observations and the frequency of inspection are shown in the following **Table 2.**

Table 2: AST Inspection and/or Test Schedule

SCHEDULED TYPE	FREQUENCY
Visual Inspection	When a tank is:
	a. Cleaned for normal operations
	b. Transferred to a new location
	c. Serviced or changed more than five (5) years after an inspection
	d. Entered for any type of maintenance or modification
Visual Inspection	At least once per year
UNSCHEDULED TYPE	**FREQUENCY**
Visual Inspection	When material changes are made to the AST facility
Test	When warranted by results of visual inspection

Each facility's bulk oil and oil products storage containers have been designed in accordance with industry standards. Generally, the containers have the following design characteristics:

1) Containers are constructed of a material that is compatible with the oil and oil products stored and the conditions of storage;

2) Most oil bulk storage containers are constructed of welded steel to API standards;

3) Some of the oil bulk storage containers have overflow equalizing lines;

4) The containers have adequate capacity to ensure that a container will not overflow should operating personnel be delayed in making their rounds;

5) Containers are provided with adequate pressure/vacuum relief;

6) All containers are operated within "Safe Fill" levels positioned below the capacity limits of the container;

7) Containers are connected with check valves that would prevent backflow;

8) Some containers are equipped with tank high level alarms to prevent overfill;

9) All alarms are monitored 24 hours/day by a system which alerts the operator of any potential problems;

10) Many separators are equipped with both high and low pressure alarms to alert operators to abnormal operating conditions; and

Waste Management and Disposal Methods

A major oil spill response would generate significant quantities of waste materials ranging from oily debris and sorbent materials to sanitation water and used batteries. All these wastes need to be classified and separated (i.e., oily, liquid, etc.), transported from the site, and treated and/or disposed of at approved disposal sites. Each of these activities demands that certain health and safety precautions be taken, which are strictly controlled by federal and state laws and regulations. This section provides an overview of the applicable state regulations governing waste disposal, and a discussion of various waste classification, handling, transfer, storage, and disposal techniques.

Waste Classification

Oily - Liquid Wastes
Oily liquid wastes (i.e., oily water and emulsions) that would be handled, stored, and disposed of during response operations are very similar to those handled during routine storage and transfer operations. The largest volume of oily liquid wastes would be produced by recovery operations (e.g., through the use of vacuum devices or skimmers). In addition, oily water and emulsions would be generated by vehicle operations (e.g., spent motor oils, lubricants, etc.), and equipment cleaning operations.

Non-Oily - Liquid Wastes
Response operations would also produce considerable quantities of non-oily liquid wastes. Water and other non-oily liquid wastes would be generated by the storage area and storm water collection systems, vessel and equipment cleaning (i.e., water contaminated with cleaning agents), and office and field operations (i.e., sewage, construction activities).

Oily - Solid/Semi-Solid Wastes
Oily solid/semi-solid wastes that would be generated by containment and recovery operations include damaged or worn-out booms, disposable/soiled equipment, used sorbent materials, saturated soils, contaminated beach sediments, driftwood, and other debris.

Non-Oily - Solid/Semi-Solid Wastes
Non-oily solid/semi-solid wastes would be generated by emergency construction operations (e.g., scrap, wood, pipe, and wiring) and office and field operations (i.e., refuse). Vessel, vehicle, and aircraft operations also produce solid wastes.

Waste Handling

A primary concern in the handling of recovered oil and oily debris is contaminating unaffected areas or recontamination of already cleaned areas. Oily wastes generated during the response operations would need to be separated by type and transferred to temporary storage areas and/or transported to approved disposal sites. Proper handling of oil and oily wastes is imperative to ensure personnel health and safety and protection of the environment.

Safety Considerations
Care would be taken to avoid or minimize direct contact with oily wastes. All personnel handling or coming into contact with oily wastes would wear protective clothing. Safety goggles would be worn by personnel involved in waste handling activities where splashing might occur. Any portion of the skin exposed to oily waste would be washed with soap and water as soon as possible. Decontamination zones would be set up during response operations to ensure personnel are treated for oil exposure.

Waste Transfer
During response operations, it may be necessary to transfer recovered oil and oily debris from one point to another several times before the oil and oily debris are ultimately recycled, incinerated or disposed of at an appropriate disposal site. There are four (4) general classes of transfer systems that may be employed to affect oily waste transfer operations:

- **Pumps:** Rotary pumps, such as centrifugal pumps, may be used when transferring large volumes of oil, but they may not be appropriate for pumping mixtures of oil and water due to their poor suction characteristics. The extreme shearing action of centrifugal pumps tends to emulsify oil and water, thereby increasing the viscosity of the mixture and causing low, inefficient transfer rates. The resultant emulsion would also be more difficult to separate into oil and water fractions. Lobe or "positive displacement" pumps work well on heavy, viscous oils, and do not emulsify the oil/water mixture. Double-acting piston and double-acting diaphragm pumps are reciprocating pumps that may also be used to pump oily wastes.

- **Vacuum Systems:** A vacuum truck may be used to transfer viscous oils but they usually pick up a very high water/oil ratio.

- **Belt/Screw Conveyors:** Conveyors may be used to transfer oily wastes containing a large amount of debris. These systems can transfer weathered debris laden oil either horizontally or vertically for short distances (i.e., 10 feet) but are bulky and difficult to set up and operate.

- **Wheeled Vehicles:** Wheeled vehicles may be used to transfer liquid wastes or oily debris to storage or disposal sites. These vehicles have a limited transfer volume (i.e., 100 barrels) and require good site access.

Waste Storage

Interim storage of recovered oil, oily and non-oily waste would be considered to be an available means of holding the wastes until a final management method is selected. In addition, the segregation of wastes according to type would facilitate the appropriate method of disposal. The storage method used would depend upon:

- The type and volume of material to be stored.
- The duration of storage.
- Access.

Temporary storage sites should use the best achievable technology to protect the environment and human health. They should be set up to prevent leakage, contact, and subsequent absorption of oil by the soil. The sites should be bermed (1 to 1.5 meters high) and double lined with plastic or polysheeting such as Visqueen sheets 6-10 millimeters or greater in thickness, without joints, prior to receiving loose and bagged debris. The edges of the sheet should be weighted with stones or earth to prevent damage by wind, and the sheet should be placed on a sand layer or an underfelt thick enough to prevent piercing. A reinforced access area for vehicles at the edge of the site should be provided. In addition, the oily debris should be covered by secured polysheeting or water resistant tarps and an adequate storm water runoff collection system for the size and location of the site would be utilized. Additionally, the sites should be at least 3 meters above mean sea level.

Oily debris can be hauled to an approved temporary storage sites in polysheet lined trucks or other vehicles. Burnable, non-burnable, treatable and re-usable materials can be placed in well defined separate areas at temporary storage sites.

When the last of the oily debris leaves a temporary storage site, the ground protection would be removed and disposed of with the rest of the oily debris. Any surrounding soil which has become contaminated with oil would also be removed for disposal or treatment. If the soils were removed for treatment, they may be replaced if testing proves acceptable levels have been achieved. Treatment and remediation is encouraged when feasible. The temporary storage should be returned to its original condition.

Waste Disposal

Techniques for Disposal of Recovered Oil
Recovery, reuse, and recycling are the best choices for remediation of a spill, thereby reducing the amount of oily debris to be bermed onsite or disposed of at a solid waste landfill. Treatment is the next best alternative, including incineration and burning for energy recovery. There are some limitations and considerations in incinerating for disposal. Environmental quality of incineration varies with the type and age of the facility. Therefore, when incineration becomes an option during an event, local air quality authorities would be contacted for advice about efficiency and emissions of facilities within their authority. Approval of the local air authorities is a requirement for any incineration option. Land filling is the last option. Final disposal at a solid waste landfill is the least environmentally sound method of dealing with a waste problem such as oily debris.

Recycling
This technique entails removing water from the oil and blending the oil with uncontaminated oil. Recovered oil can be shipped to refineries provided that it is exempt from hazardous waste regulations. There it can be treated to remove water and debris, and then blended and sold as a commercial product.

Incineration
This technique entails the complete destruction of the recovered oil by high temperature thermal oxidation reactions. There are licensed incineration facilities as well as portable incinerators that may be brought to a spill site. Incineration would require the approval of the local Air Pollution Control Authority. Factors to consider when selecting an appropriate site for onsite incineration would include:

- Proximity to recovery locations.
- Access to recovery locations.
- Adequate fire control.
- Approval of the local air pollution control authorities.

In Situ Burning/Open Burning
Burning techniques entail igniting oil or oiled debris and allowing it to burn under ambient conditions. These disposal techniques are subject to restrictions and permit requirements established by federal, state and local laws. They would not be used to burn PCBs, waste oil containing more than 1,000 parts per million of halogenated solvents, or other substances regulated by the EPA. Permission for in situ burning may be difficult to obtain near populated areas.

As a general rule, in situ burning would be appropriate only when atmospheric conditions will allow the smoke to rise several hundred feet and rapidly dissipate. Smoke from burning oil will normally rise until its temperature drops to equal the ambient temperature. Afterwards, it will travel in a horizontal direction under the influence of prevailing winds.

Landfill Disposal
This technique entails burying the recovered oil in an approved landfill in accordance with regulatory procedures. Landfill disposal of free liquids is prohibited by federal law in the United States.

With local health department approval, non-burnable debris which consists of oiled plastics, gravel and oiled vegetation, kelp, and other organic material may be transported to a licensed, lined, approved municipal or private landfill and disposed of in accordance with the landfill guidelines and regulations. Landfill designation would be planned only for those wastes that have been found to be unacceptable by each of the other disposal options (e.g., waste reduction, recycling, energy recovery). Wastes would be disposed of only at approved disposal facilities.

Good Housekeeping

Clean, orderly facilities will be maintained to reduce the possibility of accidental spills, facilitate the discovery of spills and improve response time in responding to spills. Appropriate solid waste disposal facilities will be located on site to facilitate the proper disposal of litter. The area around bulk storage tanks and secondary containment structures will be kept clean of garbage, vegetation, and debris.

Visible discharges from facilities storage tanks will be promptly cleaned up and properly disposed of according to sound environmental practices and the Waste Management and Disposal section of this Plan.

Discharges will be promptly cleaned up and removed from within secondary containment structures

The facility installations have been engineered in accordance with good engineering practices in order to prevent discharges; [redacted] shall utilize any of the following options.

i. Container capacity adequate to assure no overfills if pumper/gauger is delayed in making regularly scheduled rounds;

ii. Overflow equalization lines between containers so that a full container can overflow to adjacent container;

iii. Vacuum protection adequate to prevent container collapse during a pipeline run or other transfer of oil from the container; and/or

iv. High-level sensors to generate and transmit an alarm signal to the computer where the facility is subject to a computer production control system.

There is also a chance of a discharge when fluids are being transferred from the storage tanks to outside of the secondary containment wall. When custody is being transferred by flowlines, there are periodic inspections to detect discharges as defined in the flowline maintenance program of the SPCC Plan. When custody is being transferred by truck, there are people present to monitor the transfer. Thus, the likelihood of a spill is diminished. Should one occur, its size should be small and someone will be present to immediately shut down the facility. Truck transfer may occur outside the secondary containment area and could occasionally suffer a minor leak as hoses are disconnected. If the collection point falls outside the walls of this facility, a catch basin and a drip bucket with a lid shall be used underneath the connection to catch any leaks or drips and it shall be emptied back into the oil storage tanks or the contents disposed of properly.

Table 3: List of Acronyms

Table Legend					
	CONTENTS		**CONSTRUCTION**		**EQUIPMENT**
BS&W	Basic Sediment & Water	**B**	Bolted	**ABD**	Abandoned
CON	Condensate	**C**	Closed	**CHEM**	Chemical Tank
FW	Freshwater	**FG**	Fiberglass	**DEHD**	Dehydrator
OIL	Crude Oil	**M**	Molded	**FWKO**	Freshwater Knock-Out
PW	Produced Water	**O**	Open	**GB**	Gun Barrel
SW	Saltwater	**P**	Plastic	**HT**	Heater Treater
	CONTAINMENT/FOUNDATION	**POLY**	Polyturethane	**IH**	Inline Heater
CMT	Cement	**PVC**	Polyvinyl Chloride	**NIU**	Not In Use
E	Earthen Materials	**S**	Steel	**SCRUB**	Scrubber
E&G	Eathern Materials and Gravel	**W**	Welded	**SEP**	Separator
G	Gravel	**WD**	Wood	**STKPK**	Stack Pack
PT	Plastic Tub		**LOCATION**		**NOTE IF RAISED**
S	Steel	**BG**	Below Ground	**R**	Raised
ST	Steel Tub	**PB**	Partially Buried	**R-H**	Raised Horizontal
T	Trucks	**PPL**	Pipeline	**RPT**	Rupture
R/L	Rupture/Leak	**R/L/O**	Rupture/Leak, Overflow	**LK**	Leak
L/O	Leak/Overflow	**OVF**	Overflow		

#58 West

Onshore Oil Production
Forest County, Pennsylvania

Table 4: Local Emergency Contacts

Local Agencies			
Forest County LEPC		Injury requiring hospitalization or fatality. Fire, explosion, or other impact that could affect public safety.	Immediately(verbal)
Phone:	814.755.3541		
Address:	P.O. Box 217 Tionesta, Pennsylvania 16353		
Sheffield Volunteer Fire Department			
Phone:	814.968.5511		
Address:	318 South Main Street, Sheffield, Pennsylvania 16347		
State Agencies			
Pennsylvania Department Of Environmental Protection		Release exceeding 24-hour reportable quantity Impact to areas beyond the facility's confines Any discharge that occurs beyond boundaries of facility to creeks, ponds, rivers, etc	Immediately(verbal) and written within 10 days
District Northwest			
Phone:	814.332.6860		
Address:	230 Chestnut Street Meadville, Pennsylvania 16335		

Table 5: [redacted]esponsible Officials and Facility Personnel

Name	Title	Telephone	Address
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

Table 6: Additional Emergency Contact Information

Additional Emergency Agencies	Name	Phone
Police Department	Sheffield Township Police	814.968.5610
Ambulance		911
Local Hospital	Kane Community Hospital	814.837.4785
Sheriff's Department	Forest County Sheriff's Office	814.755.3541
Department of Environmental Quality		717.772.2199
Department of Wildlife Conservation		570.398.4744
State Fire Marshal		717.248.1115
State Highway Patrol		717.248.5599
Water Resources Board		717.787.5017

Table 7: Emergency Contractor and Contact Information

Emergency Response Contractors	Company	Phone
Environmental Services and Supplies	[redacted]	[redacted]
Backhoe/Dozer/Heavy Equipment	[redacted]	[redacted]
Vacuum Truck/Tanker/Frac Tanks	[redacted]	[redacted]
Roustabout Crews	[redacted]	[redacted]

Table 8 - Area #1 Vessels

VESSEL NUMBER	1	2	3	4
Vessel Use	OIL/SW	SW	SEP	SEP
Nominal Capacity (bbl)	209.83	71.62	4.37	4.37
Nominal Capacity (gallons)	8812	3008	184	184
Direction of Flow	NE	NE	NE	NE
Nominal Diameter	10	8	2.5	2.5
Nominal Height	15	8	5	5
Type of Vessel	W	W	W	W
Material	S	S	S	S
Vessel Top	C	C	C	C
Vessel Foundation	S	E	WD	WD
Transportation	T	T	-	-
Note if Raised	-	-	-	-
Type of Failure	R/L/O	R/L/O	R/L	R/L
Total Diked Area Capacity (bbls)	209.83	281.45	285.82	290.19
Secondary Containment	E	E	E	E

[redacted]

PPC PLAN

Preparedness, Prevention, and Contingency Plan

[redacted]

Table of Contents

Description of Plan Elements

Description of Facilities

1. Description of the Industrial or Commercial Activity

[redacted] facility locations consist of the following:

- Corporate Office located in [redacted] PA consisting of office space and parking area
- Equipment Shop located near [redacted] PA consisting of garage, equipment storage area, and parking area.

[redacted] currently operates over 300 natural gas and combination oil/natural gas wells and associated pipelines, several small compressors, and ancillary production enhancement equipment throughout various counties in Pennsylvania including Allegheny, Armstrong, Cambria, Clearfield, Fayette, Greene, Indiana, Washington and Westmoreland Counties.

The following materials may be potentially stored at these facilities and/or sites: paint cans, solvent, scrap metal, new and/or old pipe, methanol, drilling soap, production soap, drip fluid. Materials generated at the well sites include drill cuttings, fracturing fluids, crude oil, natural gas, produced water, and well servicing fluids. Materials and waste inventory is provided in Appendix A attached at the end of this document.

Drilling and operating natural gas wells is the commercial activity of [redacted]. These gas wells produce natural gas from the Venango and Bradford horizons. The construction of these wells typically impact approximately 15,000 square feet. Some gas wells in the future may produce from the Marcellus Shale. DEP specifies this Marcellus shale type of gas well as a conservation well that penetrates the Onondaga Limestone formation. The area impacted around this commercial activity will cover a total of 90,000 square feet or approximately an area 300ft x 300ft. Natural Gas is the product generated and piped into existing pipeline infrastructure for sale. During the construction, treatment, and production of these wells wastes will be generated. These wastes will be excess cement, drill cuttings (rock), brine water, sand, and hydro-fracturing additives

2. Description of Existing Emergency Response Plans

This PPC Plan is the only plan developed for the sole purpose of pollution incident prevention or emergency response preparedness. Erosion and Sedimentation (E & S) Plans are prepared by professional consultants for each project prior to the construction of new access roads, well sites or stream crossings. Field representatives assure that contractors

implement the Best Management Practices devices outlined in the E & S Plan. Temporary BMPs are installed prior to earthmoving activities and permanent BMPs are maintained throughout the life of the well.

3. Material and Waste Inventory
Refer to the attached sheets contained in Appendix A.

The location of these materials and wastes are indicated on the attached sheets. These MSDS are readily accessible to all employees and are included in Appendix A.

All wastes generated from the drilling, fracturing, production, and plugging activities are controlled and disposed of in manners consistent with regulations of the DEP as set forth in 25 PA Code 78.55 through 78.63.

4. Pollution Incident History
None

5. Implementation Schedule for Plan Elements Not Currently in Place
Equipment and personnel will be provided as necessary to meet the needs of the Implementation Schedule.

Description of How Plan is Implemented by Organization

1. Organizational Structure for Plan Implementation
[redacted] employees are responsible for implementing, maintaining and updating the PPC Plan. The Plan will be reviewed and updated as needed to reflect any changes at the facilities or well sites. If the plan fails in an emergency, the plan will be reviewed and revised to meet our needs. Each person listed as an Emergency Contact in Appendix F and under List of Emergency Contacts should be thoroughly familiar with all the information included in the PPC Plan and should have access to a copy of the Plan.

2. List of Emergency Contacts and Chain of Command

In an emergency, contact the following individuals in the order shown. The list is the order in which they will assume responsibility as alternates.

Contact	Title	Phone No.
[redacted]		

3. Duties and Responsibilities of the Coordinator

When there is a potential emergency situation, the Emergency Coordinator must ensure that the appropriate personnel are notified. Adequate control measures, such as applying absorbent materials to a spill, constructing dikes or dams to prevent material from entering drainage systems or waterways, covering drains, etc., should be implemented by the appropriate site/contractor personnel. The Emergency Coordinator should oversee these activities to ensure that they are conducted properly.

The Emergency Coordinator must immediately notify the appropriate response agencies such as the local fire company, local or State Police, PA Department of Environmental Protection, County Hazmat units, etc., depending on the nature and magnitude of the emergency.

When notifying emergency response agencies, the following information should be given and documented on the Spill Documentation Form (Appendix C):

- Name of the person reporting the emergency
- Name and location of the site
- Phone number where Emergency Coordinator can be reached
- Date, time and location of incident
- Brief description of the emergency; type(s) and quantities of material involved, extent of injuries (if any), potential hazards to health, safety and environment. (Refer to the MSDS, Emergency Response Guidebook, etc.)
  Extent of contamination (if any) to soil, air, or water, if known
- Weather conditions

It is the Emergency Coordinator's responsibility to attempt to assess the emergency to determine the appropriate actions and take all reasonable measures to stabilize the situation. If the Emergency Coordinator determines that site personnel are not adequately trained to contain the spill or release or conduct cleanup activities, the Emergency Coordinator will then contact an emergency response contractor to respond to the emergency/incident.

After an emergency, the Emergency Coordinator (with PA DEP approval) must ensure that waste material generated during emergency is properly contained and stored on site. The material will then be transported off site to a properly permitted treatment, storage, and/or disposal (TSD) facility. The Emergency Coordinator must also ensure that any equipment or supplies used during an emergency are adequately decontaminated and/or restocked so that appropriate equipment and supplies will be readily available in the event of another emergency.

SPILL – LEAK PREVENTION AND RESPONSE

1. Pre-Release Planning

The primary sources of possible pollutants (including waste) are listed below with the pollution incident prevention practices also indicated.

Well Drilling

A drill pit is constructed prior to drilling to safely store fluids resulting from the drilling and possibly fracturing operations. The drill pit is constructed to be structurally stable and lined with an impermeable, DEP approved liner. The bottom of the pit is a minimum of 20 inches above the seasonal high groundwater table. At least 2 (two) feet of freeboard is maintained at all times to prevent over shoot. The pit liner is used to store and possibly encapsulate generated drill cuttings that settle to the bottom of the pit. Flow back lines and cement return troughs are directed into the pit. Fluids remaining are removed by a vacuum truck and hauled to an approved treatment and disposal facility.

Top-hole Water (Fresh water encountered during drilling)

Land application of top-hole water is permitted as long as no additives, drilling muds, pollution materials or drilling fluids other than gases are contained in the fresh water and it meets the following requirements:

a. The pH is not less than 6 nor greater than 9 standard units
b. The specific conductance is less than 1,000 umHos/cm
c. No sheen from oil and grease
d. The area of application is not within 200 feet of a water supply or 100 feet from a stream or wetland
e. The discharge water must be spread over an undisturbed, vegetated area capable of absorbing the water and filtering solids
f. Erosion and Sedimentation (E & S) Plan BMPs are in place and functioning

Well Stimulation (Fracturing)

Wastes generated following well stimulation include flow back water which may contain, but will not be limited to, fresh and brine water, hydrochloric acid, minimal amounts of sand, friction reducer, biocide, flow enhancer and scale inhibitor. Additionally, directional shape charges consisting of dynamite may be used to perforate any steel production casing that may be installed in the well and cemented in-place.

Other than fresh and brine water, all of the above materials are provided by and transported onto the location by the contracted stimulation service company. None of these individual products are stored in bulk volumes at the well site. Small spills that may occur during stimulation activities will be quickly contained and cleaned up. Wastes will be transported to an approved treatment and/or disposal facility. Flow back fluids may contain residual amounts of any of the above-spent products used in the well stimulation procedure.

Following flow back, liquid wastes generated are removed and transported to an approved treatment/disposal facility. Sand and other suspended solids are allowed to settle to the bottom of the pit and will be disposed of in a manner similar to drill cuttings as described above and in accordance with applicable DEP regulations. The site will be reclaimed and re-vegetated using the methods outlined in the E & S Plan for pit encapsulation, unless land application is approved by the DEP.

Temporary Impoundments (used for well stimulation)

If an impoundment is constructed to store fresh water and/or other liquids generated during well stimulation, the temporary impoundment will meet the following requirements:

a. Constructed to be less than 15 feet in depth with a storage volume less than 50 acre-ft.
b. Constructed to be structurally stable and lined with an impermeable, DEP approved, liner
c. Routinely inspected to ensure structural stability and leaks are not occurring
d. The bottom of the pit is a minimum of 20 inches above the seasonal high groundwater table
e. At least 2 (two) feet of freeboard is maintained at all times
f. Safety fence is installed surrounding the pit, as necessary, to ensure worker safety
g. Flow back fluids remaining are removed by a vacuum truck and hauled to an approved treatment and disposal facility
h. Utilize the additional methods described above in *Well Stimulation (Fracturing)*

Well Production Fluids

Produced liquids from production (brine water and possible crude oil) are stored in aboveground tanks at the well location or at a central tank location (battery) for multi-well projects.

Aboveground Storage Tanks (ASTs)

There are a variety of ASTs available for use at the well sites, including but not limited to 50 barrel (bbl), 100 bbl, and 200 bbl, and constructed of steel, fiberglass, or polyethylene. Precautionary measures taken:

a. Venting capacity suitable for fill and withdrawal rates
b. Tanks checked for capacity prior to being filled
c. No loose or combustible material, empty or full drums are permitted within the containment areas
d. Hoses and fittings checked for proper connection before unloading begins
e. No smoking signs posted as necessary
f. Fire extinguishers available in all company vehicles

Stormwater Runoff

a. Implementation of site-specific Erosion and Sedimentation Plans
b. Collection basins (if any) are periodically cleaned out
c. Stormwater best management practices (BMPs) are included as Appendix D.

Material Compatibility

All environmentally sensitive materials are stored in appropriate containers, tanks, enclosed structures as necessary. Compatible materials are stored together and approved containers are used to store waste materials. Wastes are segregated and not mixed. ASTs are dedicated to compatible materials (i.e., Crude oil and Brine). No Underground Storage Tanks are utilized in the operations.

Inspection and Monitoring Program

On a weekly basis, or as needed, the following areas are visually observed for any problems and any unusual conditions are immediately reported to the Emergency Coordinator:

a. Storage area for materials brought in from the field
b. ASTs for visual material levels, leaks in lines or tanks, outlet valves properly closed, hoses kept inside containment areas
c. Equipment for leaks in lines/hoses, etc.
d. Tanks and piping for corrosion or leaking valves and proper labeling
e. Labeling on all chemical products, Right-To-Know information readily available and accessible at facility locations

On a monthly basis, or as needed, an in-depth inspection of all well meter runs, valves, above ground piping, well heads, pumpjacks and compressors is conducted. On a yearly basis, or as needed, an in-depth inspection of all pipeline valves and drips is conducted.

Preventive Maintenance

A preventive maintenance program is in place for equipment and tanks containing environmentally sensitive materials. The following is a description of the activities conducted:

a. Hoses and fittings are checked for signs of leakage, loose fittings are tightened or replaced as needed
b. Wires are checked for frays on electrical motors
c. Piping runs and valves are checked for leaks and corrosion and repaired or replaced as needed

Housekeeping Program

a. Regular refuse pick up and disposal is conducted
b. Small spills are quickly cleaned up with absorbent materials (pads, socks, pillows, loose absorbent, etc.) and collected for proper disposal

Security

Facilities are locked and lights are available for night operations and security. Well locations are typically in production 24 hours a day, 7 days a week, 365 days a year.

External Factors Planning

The only external factor, which could have serious impact on the health and safety of the public and employees, would be a fire. In the event of such an occurrence, the appropriate agencies would be immediately contacted. Flooding, power outages, or snowstorms would have minimal impact or effect in operations.

Employee Training Program

The following training is provided to the appropriate employees:

a. *Right-To-Know*: Based on the requirements of The Right-To-Know Law (Act 159 of 1984), an employee has a legal right to know the identity of hazardous substances used in the workplace and the health hazards posed by exposure to these substances. Annual training is provided to every employee that uses, handles, or is exposed to hazardous substances in the workplace.
b. *PPC Training*
c. OSHA safety training
d. In-house individual job duty specific training

COUNTERMEASURES

Countermeasures Undertaken by Facility and Contractors

a. In the event of a spill or major leak of an environmentally sensitive material, the first priority is to attempt to stop the cause of the spill/release. This must be done using the proper precautions and appropriate personal protective equipment. If the material is unknown, attempt to identify the material by labels, placards, other markings, etc.
b. Outside contractors will/may be utilized as necessary to assist with the spill response, regardless of the size or nature of the material released. The contractors will report to and be directed by the Emergency Coordinator.
c. Once the material is identified, appropriate measures must be implemented (with proper protection for workers) to stop the spread of the spill and to prevent it from entering and drains or waterways. Use spill kits (pads, socks, pillows, blankets, and loose absorbent) to control smaller spills. Place absorbent materials in a fashion that will prevent the material from migrating any further. In the event of a large spill, use of equipment, shovels, and other appropriate tools to move sand or other material to construct a dike/containment structure will help to collect the material and prevent further spread or flow into any drainage system.
d. If a material spills near a drain/inlet, use drain stopper mats to prevent the material from entering the drain/inlet.
e. If material gets into a waterway, prevent the material from getting further downstream by placing booms across the entire width of the waterway (at a point downstream from the spilled material), preferably at a narrow point. Use absorbent pads to absorb material that may be floating on the surface.

f. If material spills in an area with secondary containment, ensure valves are closed on the on the containment structure and collect spilled material with absorbents. Once the material has been absorbed, collect used absorbents (pads, pillows, socks, blankets, etc.) in an empty, approved, 3-ringed, 55 gallon drum for appropriate waste inventory and proper disposal.
g. After a spill has been contained and the immediate emergency has subsided, cleanup of the spill material should be initiated. Use shovels or equipment, as necessary, to complete cleanup. If the material spilled on soil, remove any stained soil. Use of proper personal protective equipment, such as protective suits, gloves, safety glasses, coveralls, etc., must be worn to protect employees. After cleanup, decontamination of equipment must be completed. Spill kits and absorbent materials must be restocked.

Emergency Response Contractors

Contractors to be utilized in the case of an emergency are included in Appendix E.

Internal and External Communication and Alarm Systems

The facilities are equipped with a telephone capable of making external contacts. All field personnel are provided a cell phone to enhance field communications.

Evacuation Plan for Personnel

The corporate office is equipped with a paging system that can be operated from any phone. Personnel shall exit the facilities through the main entrance doors (if possible) or other exits. All facilities and field vehicles are equipped with portable fire extinguishers and first aid kits.

Personnel working at field locations are directed to get away from the affected area as quickly as possible and call for assistance to the appropriate Emergency Contact.

Emergency Equipment Available for Response

Spill Kits - Will be maintained at any field facility
Fire Extinguishers – Available at the facilities and in all company vehicles
First Aid Kits – Available at the facilities and in all company vehicles
Eye Wash Stations – Available at the facilities
Communication Equipment – Available at the facilities and in all company vehicles
Heavy Equipment – Utilized through contractors
Hand Tools – Available at the facilities

EMERGENCY SPILL CONTROL NETWORK

Arrangements with Local Emergency Response Agencies

Most local police, fire, EMS, and HAZMAT emergency response teams are familiar with operations involving oil and gas wells.

Emergency Notification List

The Emergency Notification List is included as Appendix F.

Downstream Notification Requirements for Storage Tanks

The downstream notification requirement is not applicable for this facility. Aggregate aboveground storage tank capacity does not exceed 21,000 gallons at facility locations or at each well site and storage tank batteries (if applicable).

ATTACHMENT 17

Letter from Inland Tarp and Liner re Comparison of 20 mil and 30 mil Liner Products

February 20th 2016

To whom it may concern:
Inland Tarp & Liner LLC has been in business for 35 years and I have been in the Marcellus/Utica area selling liners for 7 years now. In 2011 we had the EPA 9090 test done on our 20 and 30 mil Coated Woven Polyethylene. The 30mil was approved for flow back water on the PA Bulletin. The reason the 30 mil was approved was because it was for the Unconventional drilling companies using large flow back impoundments. I would like to ask you to take a look at the comparison sheet that I have attached and compare our 20mil CWPE to 30mil LLDPE. If you compare the tear strengths, puncture resistance, and Mullen burst (Page 8) you will see that the 20 mil CWPE is a superior product. We have also had the CWPE tested for permeability and it far exceeds the numbers that are stated in your proposed regulation. (Please see below)

There are many benefits for using our CWPE including but not limited to:
- ☐ **Lighter weight which means we can do large prefabricated panels eliminating seams in the field. (We have high QA/QC standards in our factory's controlled atmosphere)**
- ☐ **More flexible which means that the material will be easier to handle and work with.**
- ☐ **Reinforced which means it is stronger.**
- ☐ **Less expensive which in turn will help keep the Conventional Driller in business.**

(1) Subsurface [secondary] containment systems must have a coefficient of permeability of no greater than 1 x 10-10 cm/sec with sufficient strength and thickness to maintain the integrity of the containment system. The thickness of a subsurface containment system must be at least 30 mils. Adjoining sections of the subsurface containment system must be sealed together, in accordance with the manufacturer's directions, to prevent leakage. All seams of the adjoining sections shall have their integrity tested prior to being covered.
Thank you for your attention on this matter

Best Regards,
Matthew Willis

Matt Willis

East Coast Liner Sales

Cell: 814.367.7447

ATTACHMENT 18

Letter from DEP Approving Horner Plastics 20 mil Polyethylene Plastic Sheeting Product, With Specifications Sheet

Pennsylvania Department of Environmental Protection

Rachel Carson State Office Building
P.O. Box 8765
Harrisburg, PA 17105-8765
December 20, 2002

Bureau of Oil and Gas Management

717-772-2199
FAX 717-772-2291

Mr. Rick Horner
Horner Plastic Inc.
P.O. Box 19
Oliveburg, PA. 15764

Dear Mr. Horner:

Horner Plastic Inc.'s 2080B (20 mil medium density) polyethylene liner is approved for containing drill cuttings from below the casing seat, and drilling, exploration and production waste as described in 25 Pa. Code §§ 78.61(c) and 78.62. The 2080B is approved as providing equal or superior protection as the 30 mil liner requirements in 25 Pa. Code § 78.62.

Notice of the approval should appear in the *Pennsylvania Bulletin* on January 4, 2003. Enclosed is a copy of the notice that is being placed in the *Pennsylvania Bulletin.*

If you have any questions, please contact Orest Kolodij at 717-772-2199; e-mail okolodij@state.pa.us .

Sincerely Yours,

Ronald P. Gilius
Chief
Surface Activities Division

Enclosure

HORNER PLASTICS, INC.
4146 ROUTE 36
OLIVEBURG, PA. 15764
PHONE: (814) 938-4489
FAX: (814) 938-4399

****

SPECIFICATIONS FOR POLYETHYLENE PLASTIC SHEETING

USED FOR SUB SURFACE LIQUID STORAGE, PRIMARILY IN THE COAL, GAS, AND OILFIELD INDUSTRY. PANELS ARE HOT AIR WELDED IN OUR PLANT TO ACHIEVE DESIRED SIZE REQUIRED. ALL FACTORY SEAMS HAVE THE "HORNER PLASTICS, INC." INSIGNIA FOR EASY IN FIELD PRODUCT IDENTIFICATION. FINISHED GOODS ARE ACCORDION FOLDED AND ROLLED ON 6" CORES FOR EASE OF INSTALLATION.

2080 BLACK (2080B)

PROPERTIES	TEST METHOD	VALUES
THICKNESS, NOMINAL		20 MIL
THICKNESS, MINIMAL		17 MIL
WEIGHT PER MSF		100 LBS.
1" TENSILE STRENGTH	ASTM D882	55 LBS.
ELONGATION @ BREAK	ASTM D882	1000%
*GRAB TENSILE	ASTM D751	170 LBS.
*TEAR RESISTANCE	ASTM D1004	11 LBS.
*TONGUE TEAR	ASTM D751	30 LBS.
*TRAPEZOID TEAR	ASTM D751	60 LBS.
HYDROSTATIC RESISTANCE	ASTM D751	90 PSI
MINIMUM USE TEMPERATURE		-70 DEG.F.
MAXIMUM USE TEMPERATURE		+180 DEG.F.
DENSITY (MEDIUM)		.925 - .936
VAPOR TRANSMISSION	ASTM D96/A	$.11 G/M^2$ DAY
COEFFICIENT OF PERMABILITY	$CM^3/CM^2/SEC.$	1.31×10^{-10} CM/SEC

*AVERAGE MD & TD

MADE IN USA

HORNER PLASTICS, INC.
4146 ROUTE 36
OLIVEBURG, PA. 15764
PHONE: (814) 938-4489
FAX: (814) 938-4399

****

SPECIFICATIONS FOR POLYETHYLENE PLASTIC SHEETING

USED FOR SUB SURFACE LIQUID STORAGE, PRIMARILY IN THE COAL, GAS, AND OILFIELD INDUSTRY. PANELS ARE HOT AIR WELDED IN OUR PLANT TO ACHIEVE DESIRED SIZE REQUIRED. ALL FACTORY SEAMS HAVE THE "HORNER PLASTICS, INC." INSIGNIA FOR EASY IN FIELD PRODUCT IDENTIFICATION. FINISHED GOODS ARE ACCORDION FOLDED AND ROLLED ON 6" CORES FOR EASE OF INSTALLATION.

3080 BLACK (3080B)

PROPERTIES	TEST METHOD	VALUES
THICKNESS, NOMINAL		30 MIL
THICKNESS, MINIMAL		27 MIL
WEIGHT PER MSF		150 LBS.
1" TENSILE STRENGTH	ASTM D882	80 LBS.
ELONGATION @ BREAK	ASTM D882	650%
*GRAB TENSILE	ASTM D751	170 LBS.
*TEAR RESISTANCE	ASTM D1004	11 LBS.
*TONGUE TEAR	ASTM D751	38 LBS.
*TRAPEZOID TEAR	ASTM D751	170 LBS
HYDROSTATIC RESISTACE	ASTM D751	65 PSI
MINIMUM USE TEMPERATURE		-70 DEG.F.
MAXIMUM USE TEMPERATURE		+180 DEG.F.
DENSITY (MEDIUM)		.925 - .936
VAPOR TRANSMISSION	ASTM D96/A	$.10 G/M^2$ DAY
COEFFICIENT OF PERMABILITY	$CM^3/CM^2/SEC.$	1.16×10^{-10} CM/SEC

*AVERAGE MD & TD

MADE IN USA

ATTACHMENT 19

DEP Right-to-Know Request Response Letter Dated June 26, 2015

pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION

June 26, 2015

VIA EMAIL

Arthur Stewart
camelot@atlanticbb.net

Re: Right-to-Know Request Number 1400-15-126

Dear Mr. Stewart:

On May 26, 2015, the open-records officer of the Department of Environmental Protection, (Department), received your written request for records. The Department is responding to your request under the Pennsylvania Right-to-Know Law, 65 P.S. §§ 67.101-67.3104 (RTKL).

You requested the following records regarding the proposed "Environmental Protection Performance Standards and Oil and Gas Well Sites" rulemaking (Proposed Rulemaking) (also known as the Chapter 78/78a, Subchapter C. rulemaking) specifically:

- Relative to the requirements contained in the Proposed Rulemaking at section 78.60 all documents that contain an identification of the financial, economic and social impact of regulation on individuals, small businesses, business and labor communities and other public and private organizations and, when practicable, an evaluation of the benefits expected as a result of the regulation.

You note that the term "an identification of the financial, economic and social impact, etc." is intended to have the same meaning as used in the Regulatory Review Act.

An initial response to your request was due on June 2, 2015. On that date you were notified that the Department required an additional 30 days, until July 2, 2015, to respond to your request.

On December 14, 2013, the Department published notice in the *Pennsylvania Bulletin* of the proposed "Environmental Protection Performance Standards at Oil and Gas Well Sites" rulemaking (Proposed Rulemaking) seeking to amend 25 Pa. Code Chapter 78, including § 78.60 as well as other sections. When the Department submitted the Proposed Rulemaking to the Legislative Reference Bureau for publication, the Department submitted its completed Regulatory Analysis Form to the Independent Regulatory Review Commission (IRRC) and the standing committees in accordance with Section 745.5(a) of the Regulatory Review Act, 71 P.S. § 745.5(a). The Regulatory Analysis Form is a form developed by IRRC and provided to agencies to include in proposed regulatory packages. *See Regulatory Review Process Manual*, http://www.irrc.state.pa.us/resources/docs/Regulatory_Review_Process_Manual.pdf.

Section 745.5(a)(10) of the Regulatory Review Act provides:

> On the same date that an agency submits a proposed regulation to the Legislative Reference Bureau for publication of notice of proposed rulemaking in the Pennsylvania Bulletin as required by the Commonwealth Documents Law, the agency shall submit to the commission and the committees a copy of the proposed regulation and a regulatory analysis form which includes . . . [a]n identification of the financial, economic and social impact of the regulation on individuals, small businesses, business and labor communities and other public and private organizations and, when practicable, an evaluation of the benefits expected as a result of the regulation . . . .

71 P.S. 745.5(a)(10). Section 745.5(a)(10) contains the only reference to an "an identification of the financial, economic and social impact, etc." in the Regulatory Review Act. For that reason, the Department interprets your request for "all documents that contain an identification of the financial, economic and social impact of the regulation on individuals, small businesses, business and labor communities and other public and private organizations and, when practicable, an evaluation of the benefits expected as a result of the regulation" relating to the Proposed Rulemaking at § 78.60 as the term "an identification of the financial, economic and social impact, etc." is used in the Regulatory Review Act as seeking the information included in the Regulatory Analysis Form provided to IRRC and the standing committees as part of the Proposed Rulemaking.

Your request is granted in part and denied in part.

The Regulatory Analysis Form, consisting of 29 pages, is electronically accessible on the Department's website at http://files.dep.state.pa.us/PublicParticipation/Public%20Participation%20Center/PubPartCenterPortalFiles/Environmental%20Quality%20Board/2013/August%2027%20EQB/Proposed%20Rulemaking%20-%20Ch%2078/RAF.pdf.

Under the RTKL, if you are unwilling or unable to access the record electronically and wish to have the record produced in paper copy, you are required to contact me within 30 days from the date of this letter. If you do not contact me within 30 days from the date of this letter, I will consider your non-communication as confirmation that you are willing and able to access the responsive record electronically.

In the event that you wish me to print and provide you a copy of the record, the duplication cost, at $.25 per page is $7.25 plus postage.

Please note that failure to pay for a record made available in response to a RTKL request to any executive agency will preclude you from obtaining further records from another executive agency, pursuant to the provisions of section 901 of the RTKL and Section IV (D) of our agency RTKL Policy, as published on our website www.depweb.state.pa.us. Also, if payment is not received and you request the same records again the request may be considered as disruptive under 65 P.S. § 67. 506(a)(1).

Outside of your RTKL request, the Department's website includes other voluminous materials on the Proposed Rulemaking and the rulemaking process. Posted records include notices, guides, proposed language, public comments, executive summaries, submissions to IRRC, news releases, webinars and transcripts of past public hearings and dates of all public hearings. In all, approximately 1,600 pages of records are available for your review at http://www.portal.state.pa.us/portal/server.pt/community/public_resources/20303/surface_regulations/1587188.

To the extent that you seek drafts of the Department's Regulatory Analysis Form for the proposed "Environmental Performance Protection Standards at Oil and Gas Well Sites" rulemaking, your request is denied for the following permissible reasons:

- **Strategy of Proposed Rulemaking/Draft Regulation.** The RTKL exempts from production records that would reveal the strategy to be used to develop or achieve the successful adoption of a regulation. 65 P.S. § 708(b)(10)(i)(B). Additionally, the RTKL also excludes from production drafts of a regulation prepared by an agency. 65 P.S. § 708(b)(9).

  Therefore, if your request seeks drafts of the Department's Regulatory Analysis Form it is denied because it would reveal the strategy to be used or developed to achieve the successful adoption of this regulation.

- **Internal, Predecisional Deliberative**. To the extent that you seek draft records of the Department's Regulatory Analysis Form, such records would reveal or reflect the Department's internal, predecisional deliberations. Consequently, these records are also exempted from disclosure under Section 708(b)(10) of the RTKL, 65 P.S. § 708(b)(10).

  Section 708(b)(10)(i)(A) of the RTKL, 65 P.S. § 67.708(b)(10) (i)(A), states that a Commonwealth agency can exempt from disclosure records that reflect "the internal, predecisional deliberations of an agency, its members, employees or officials or predecisional deliberations between agency members, employees or officials and members, employees or officials of another agency . . ., contemplated or proposed policy or course of action or any research, memos or other documents used in the pre decisional deliberations."

  Under this RTKL exception, "information that constitutes 'confidential deliberations of law or policymaking, reflecting opinions, recommendations or advice' is protected." *Carey v. Dep't of Corrections*, 61 A.3d 367, 378 (Pa. Cmwlth. 2013) (*quoting In re Interbranch Comm'n on Juvenile Justice*, 988 A.2d 1269, 1277-1278 (Pa. 2010)).

  In *Office of the Governor v. Scolforo*, 65 A.3d 1095 (Pa. Cmwlth. 2013) (*en banc*), the Commonwealth Court concluded that the invoking of this exception does not require that an agency establish that the information itself *reveals* or

"discloses" deliberative communication ... section 708(b)(10)(i)(a) of the RTKL exempts all predecisional deliberations where agency officials and/or employees "contemplate" or "propose" a future "course of action." *Id.* at 1101-1102, *citing Commonwealth v. Vartan,* 733 A.2d at 1263.

Based on this legal authority, the Department would withhold draft records of the Regulatory Analysis Form because they reflect or reveal the Department's deliberations amongst its own staff as to proposed courses of action relating to this record. Each draft is a preliminary step in this process and does not contain a final determination by the Department.

- **Attorney Client Privilege/Attorney Work Product**. If you are seeking drafts of the Department's Regulatory Analysis Form, these records are also excepted from disclosure under the RTKL as attorney-client privilege and attorney-work product.

  Section 301(a) of the RTKL, 65 P.S. § 67.301(a), requires Commonwealth agencies to provide access to "public records." Section 102 of the RTKL, 65 P.S. §67.102, defines a "public record" as, among other things, a record that "is not protected by a privilege." In other words, if a record is protected by a privilege, it is not a "public" record subject to access under Section 301(a) of the RTKL.

  Section 102 of the RTKL, 65 P.S. § 67.102, further defines the term "privilege," in pertinent part, as "the attorney-work product doctrine, the attorney-client privilege, . . . or other privilege recognized by a court interpreting the laws of this Commonwealth."

  The attorney-client privilege states:

  > In a civil matter, counsel shall not be competent or permitted to testify to confidential communications made to him by his client, nor shall the client be compelled to disclose the same, unless in either case this privilege is waived upon the trial by the client.

  42 Pa.C.S. § 5928

  To except records from disclosure under this privilege, the following four elements must be satisfied:

  > (1) the asserted holder of the privilege is or sought to become a client; (2) the person to whom the communication was made is a member of the bar of a court, or her or his subordinate; (3) the communication relates to a fact of which the attorney was informed by her or his client, without the presence of strangers, for the purpose of securing either an opinion of law, legal services,

or assistance in a legal matter, and not for the purpose of committing a crime or tort; and (4) the privilege has been claimed and is not waived by the client.

Nationwide Mutual Ins. Co. v. Fleming, 924 A.2d 1259, 1264 (Pa. Super 2007);

In addition, the Pennsylvania Supreme Court has held that the attorney-client privilege covers both confidential client to attorney communications, and confidential attorney to client communications made for the purpose of obtaining or providing legal advice. *See Gillard v. AIG Insurance Co.*, 15 A.3d 44, 58-59 (Pa. 2011). The OOR has also acknowledged that the attorney-client privilege applies to even less formal communications between a public agency and its attorneys. *Gustler v. Jefferson Township*, OOR Dkt. AP 2009-0367.

Based on the legal authority summarized above, the Department is withholding drafts of the Regulatory Analysis Form because they contain communications between Department attorney(s) and Department staff where legal advice was sought or given. The Department has not waived this privilege as to these records, and no third-party was involved that would result in the waiver of the privilege.

Furthermore, the Pennsylvania Supreme Court has stated that the attorney work-product doctrine excepts from disclosure the "mental impressions, conclusions or opinions respecting the value or merit of a claim or defense or respecting strategy or tactics, including those of a party's representative who is not the party's attorney." *LaValle v. OGC*, 769 A.2d 449, 495 (Pa. 2001), citing Pa.R.C.P. 4003.3. The Commonwealth Court has also held that records reflecting attorney-work product are not public records under the RTKL. *Maleski v. Corporate Life Ins. Co.*, 641 A.2d 1, 5 (Pa. Cmwlth. 1994).

Based on the legal authority summarized above, the Department has withheld draft records of the Department's Regulatory Analysis Form that contain the mental impressions, conclusions, comments and/or opinions of a Department attorney(s). The Department has not waived this privilege as to these records, and no third-party was involved that would result in the waiver of the privilege.

Therefore, if your request seeks drafts of the Regulatory Analysis Form it is denied as attorney-client privilege and as attorney work product.

- **Notes and Working Papers.** Pursuant to 65 P.S. §67.708(b)(12) of the RTKL, "Notes and working papers prepared by or for a public official or agency employee used solely for that official's or employee's own personal use, including telephone message slips, routing slips and other materials that do not have an official purpose" are exempt from access by a requestor. This exception under the RTKL of personal notes or work papers applies when the records at issue are not created for an official purpose. *Shields v. City of Philadelphia,* OOR

> Dkt. AP 2009-0787. However, the information contained within the record need not be personal in nature, but rather must be "purely personal in use." Id.
>
> Employees through the course of developing the Department's Regulatory Analysis Form may have taken personal notes directly on draft forms for their own personal use as reminders or memorializing issues for further discussion or research. These notes were not directed by the Department but created at the discretion of the employee for their own use. Therefore, if your request seeks drafts of the Department's Regulatory Analysis Form, it is denied for any notes the drafts contain as permitted under the RTKL as constituting personal notes and working papers.

Additionally, circumstantial evidence suggests that approximately 135 RTKL requests received by the Department from May 19, 2015 – June 1, 2015, related to the Department's Proposed Rulemaking was a concerted effort by the Pennsylvania Grade Crude Oil Coalition and its members, associated individuals, or groups to disrupt the daily operations of the Department. The Department reserves the right to deny in the future these coordinated attempts by the Pennsylvania Grade Crude Oil Coalition as the work of a singular coordinated entity and treat such requests as disruptive pursuant to 65 P.S. § 67.506(a) of the RTKL. The Department also reserves the right to raise this provision as a defense in an appeal of this response before the Office of Open Records.

You have a right to appeal this response in writing to the Executive Director, Office of Open Records (OOR), Commonwealth Keystone Building, 400 North Street, 4th Floor, Harrisburg, Pennsylvania 17120. If you choose to file an appeal you must do so within 15 business days of the mailing date of this response and send to the OOR:

1) all Department responses;
2) your request; and
3) the reason why you think the Department is wrong in its response.

Also, the OOR has an appeal form available on the OOR website at: https://www.dced.state.pa.us/public/oor/appealformgeneral.pdf.

Sincerely,

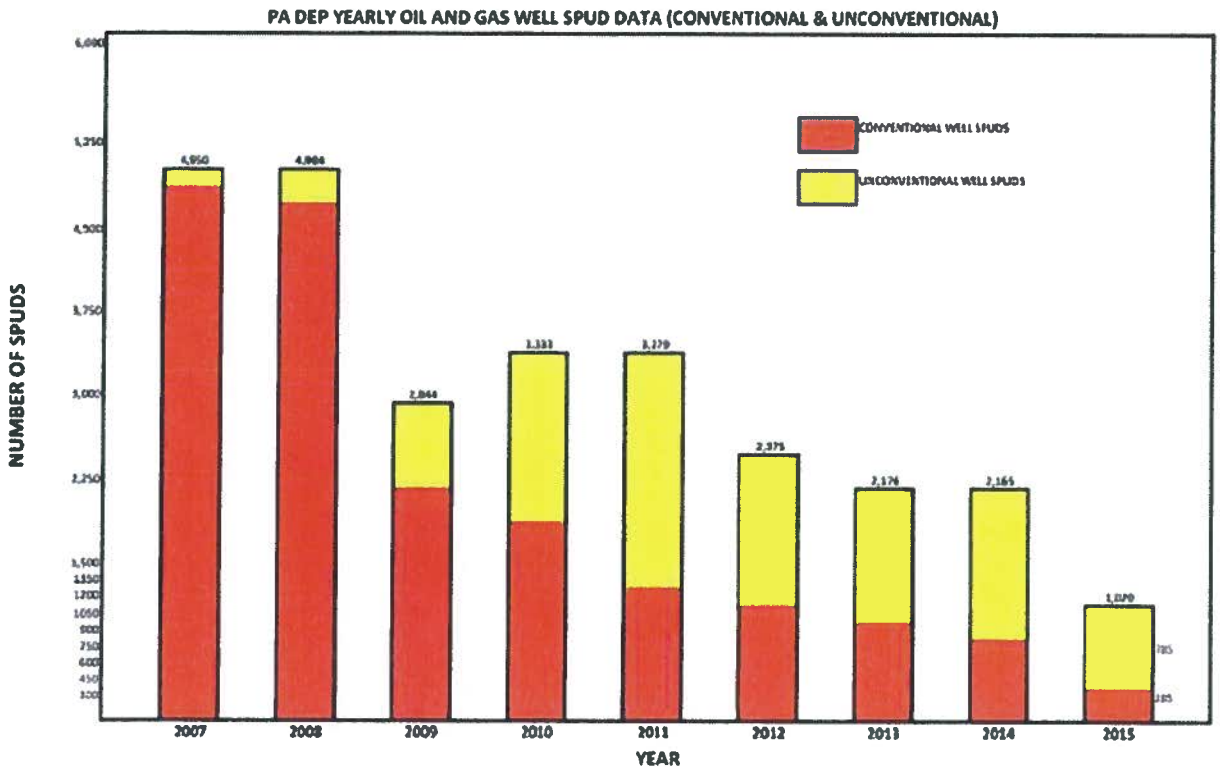
Dawn Schaef

Dawn Schaef
Agency Open Records Officer

cc: RTK Legal via email
RTK CO OG via email

ATTACHMENT 20

Chart Depicting Trends in Conventional Well Spuds From 2007-2015


PA DEP YEARLY OIL AND GAS WELL SPUD DATA (CONVENTIONAL & UNCONVENTIONAL)
CONVENTIONAL WELL SPUDS
UNCONVENTIONAL WELL SPUDS
NUMBER OF SPUDS
YEAR
2007
2008
2009
2010
2011
2012
2013
2014
2015

ATTACHMENT 21

DEP Right-to-Know Response Dated March 7, 2016 (Including April 25, 2013 Memo Entitled "Chapter 78 C costs")

pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION

March 7, 2016

Certified Receipt Number 70142870000063906131

Pennsylvania Grade Crude Oil Coalition
P.O. Box 211
Warren, PA 16365

Re: Right-to-Know Request Number 1400-16-064

Dear Requester:

On January 28, 2016, the open-records officer of the Department of Environmental Protection (Department) received your written request for records. The Department is responding to your request under the Pennsylvania Right-to-Know Law, 65 P.S. §§ 67.101-67.3104 (RTKL).

Your singular submission contained three RTKL requests.

Right to Know Request Number 1:

You are seeking records regarding staff employed by the Department. Specifically:

1) The total number of Department employees as of January of each of 2000, 2005, 2010, and 2015;
2) The number of Department employees primarily employed in the Department's oil and gas division ("primarily" meaning the majority of that employee's workday) as of January in the years 2000, 2005, 2010, and 2015; and
3) The number of Department employees in the Department's oil and gas division whose job required the employee to engage in field activities ("field activities" as going into the field to, in any way, inspect or render advice as to any oil and gas facility) as of January in the years 2000, 2005, 2010, and 2015.

Right to Know Request Number 2:

All records prepared by the Department during the last ten years that pertain to requests for additional staff or funding for additional staff, to be employed by the Department in any position relating to oil and gas activities.

Right to Know Request Number 3:

Records relating to page eighty-four of the January, 2016 Regulatory Analysis Form where the Department stated the following: "This Department reached out to well operators, subcontractors, and industry groups to derive the cost estimates of this final form rulemaking." You request all records prepared, gathered or created in association with all such "reaching out" activities used to "derive the cost estimates of this final-form rulemaking." The records are intended to include, but

are not limited to, any notice, agenda, or minutes of any meeting, any records of actual costs examined by the Department, and all correspondence between the Department and well operators, subcontractors, and industry groups relating to the "reaching out."

An initial response to your request was due on February 4, 2016. On that date, the Department notified you that it required an additional 30 days, until March 7, 2016, to respond to your request.

Your request is granted in part and denied in part and records responsive to your request are enclosed.

For each of your RTKL requests, the Department's response is as follows:

Right-to-Know Request Number 1:

Your request is granted and responsive records are enclosed with this response.

Right-to-Know Request Number 2:

Your request is granted, in part, and denied, in part. Responsive records are enclosed with this response. The Department interprets Right-to-Know Request Number 2 as seeking an outline of staffing needs from the Office of Oil and Gas Management to the Department's Bureau of Fiscal Management, as well as the rulemaking packages for fees to fund the Department's oil and gas program. To the extent that your request seeks other records, your request is insufficiently specific. Your request for all records that "pertain to requests for additional staff or funding for additional staff" is not sufficiently specific because the Department cannot ascertain what records "pertain to requests." Additionally, your request for records pertaining to requests for additional staff in "any position relating to oil and gas activities" is not sufficiency specific because the Department cannot ascertain with any specificity what you intend by the phrase "any position relating to oil and gas activities."

The Department's fee rulemakings are publically available on the Independent Regulatory Review Commission's website.

The 2009 "Marcellus Shale Well Permit Fees" (published as final on April 18, 2009) is published at: http://www.irrc.state.pa.us/regulations/RegSrchRslts.cfm?ID=2733.

The 2009 "Oil and Gas Wells" rulemaking increasing oil and gas well permit fees (published as final on October 24, 2009) is published at: http://www.irrc.state.pa.us/regulations/RegSrchRslts.cfm?ID=2734.

The 2014 "Oil and Gas Well Fee Amendments" rulemaking is published at: http://www.irrc.state.pa.us/regulations/RegSrchRslts.cfm?ID=3027. The Department also provided a report, titled "3-year Regulatory Fee and Program Cost Analysis Report To the Environmental Quality Board" that is published at:

http://files.dep.state.pa.us/PublicParticipation/Public%20Participation%20Center/PubPartCenterPortalFiles/Environmental%20Quality%20Board/2014/January%2021,%202014%20EQB%20meeting/Three%20Year%20Report%20to%20EQB.pdf.

Under the RTKL, if you are unwilling or unable to access the records electronically and wish to have the records duplicated, you are required to contact me within 30 days from receipt of this letter.

In the event that production costs exceed $100.00, the Department will provide you with an estimate of the costs and fees due, at a duplication cost of $.25 per standard page, plus postage, which must be paid prior to receiving the records. 65 P.S. § 67.704; § 67.901 and § 67.1307(h).

However, to the extent that the Department has misinterpreted this portion of your request, it is insufficiently specific.

An open-ended request that provides a Department little guidance regarding what to look for may be so burdensome that it will be considered overly broad. *Mollick v. Township of Worcester*, 32 A.3d 859, 871 (Pa. Cmwlth. 2011). The specificity of a request must be construed in the request's context, rather than envisioning everything the request might conceivably encompass. *Pa. State Police v. Office of Open Records*, 995 A.2d 515 (Pa. Cmwlth. 2010). Your request for *all* records that "pertain to requests for additional staff or funding for additional staff" and for records pertaining to requests for additional staff in "any position relating to oil and gas activities" is not sufficiency specific. As drafted, these portions of your request are exceedingly broad and do not provide any reasonable context, such as a time frame, geographic assignments, specific positions, Department activities, or identified Department personnel or offices, upon which a search for records can be conducted.

Consequently, it is then possible that some of the records you may be attempting to seek, but have not requested with sufficient specificity, may be exempt under provisions of the RTKL, including but not limited to personal identification information, 65 P.S. § 67.708(b)(6); personal security information, 65 P.S. § 67.708(b)(1)(ii); internal predecisional deliberations, 65 P.S. § 67.708(b)(10); and noncriminal investigative records, 65 P.S. § 67.708(b)(16). Furthermore, records may also be exempt as privileged, such as the attorney-client privilege or the doctrine of attorney-work product. While those defenses to production may apply, the lack of specificity of your request does not provide the Department with sufficient information to fully assert or meaningfully determine whether any applicable RTKL exceptions or privileges exist. Therefore, the Department reserves the right to review and assert any such exemptions if any portion of your request is deemed sufficiently specific, pending review of any responsive records.

You are not precluded from refining your request and submitting a new one that rectifies the search and retrieval issues of your current request as outlined within this letter.

Right-to-Know Request Number 3:

The Department interprets Right-to-Know Request Number 3 as seeking records related to the Department's "reaching out" activities" referenced on page eighty-four of the Regulatory Analysis Form that accompanied the final-form "Environmental Protection Performance Standards at Oil and Gas Well Sites" rulemaking. The Department interprets this portion of your request as seeking records related to instances that the Department independently contacted well operators, subcontractors, and industry groups outside the rulemaking process in its research of the costs associated with the rulemaking.

Based on this interpretation for this portion of your request, the Department withheld records that are excluded from production under the RTKL for the following legally permissible reasons:

- *Employee Working Notes.* Pursuant to 65 P.S. § 67.708(b)(12) of the RTKL, "[N]otes and working papers prepared by or for a public official or agency employee used solely for that official's or employee's own personal use, including telephone message slips, routing slips and other materials that do not have an official purpose" are exempt from access by a requestor.

  Notes taken while working an official capacity and solely for the convenience and sole use of an individual, are expressly exempt under the RTKL when the notes are created for the individual's personal use and not available to others. *City of Philadelphia. v. Philadelphia Inquirer,* 52 A.3d 456, 461-462 (Pa. Cmwlth. 2012) and *Morris v. Upper Leacock Twp.,* No. AP-2010-0931 (Pa. O.O.R.D. November 1, 2010). Notes not placed in the public or common files where they can be used or reviewed by other Agency employees or officials are consistent with personal use. *Id.*

  Consequently, the Department is withholding five pages of handwritten notes taken during telephone calls to operators and subcontractors regarding cost estimates associated with the rulemaking. The notes were taken for the employee's own personal use. "Personal" within the exception means documents used by an official to carry out public responsibilities personal to that official. *City of Philadelphia v. Philadelphia Inquirer,* 52 A.3d at 461- 462.

- *Internal, Predecisional Deliberation Exception.* The Department also denies your request to records that are predecisional, internal deliberations, because such records are exempt from production under the RTKL. 65 P.S. § 67.708(b)(10).

  Section 708(b)(10)(i)(A) of the RTKL states that a Commonwealth agency can withhold records that are, "The internal, pre-decisional deliberations of an agency, its members, employees or officials or pre-decisional deliberations between agency members, employees or officials and members, employees or officials of another agency..., contemplated or proposed policy or course of action of any research, memos or other documents used in the pre-decisional deliberations." 65 P.S. § 67.708(b)(10)(i)(A).

According to the language of Section 708(b)(10)(i), protected records must be internal, predecisional, and deliberative. *McGowan v. Dep't of Envtl. Protection*, 103 A.3d 374 (Pa. Cmwlth. 2014).

Furthermore, in addition to protecting records that are internal, predecisional deliberations, Section 708(b)(10)(i)(A) also protects records that "reflect" deliberations. Although "reflect" is not expressly defined in the RTKL, it was discussed at length by the Commonwealth Court in *Office of the Governor v. Scolforo*, 65 A.3d 1095 (Pa. Cmwlth. 2013) (en banc) (*Scolforo*). The Court stated:

> [W]e recognize that the General Assembly utilized the specific term "reflect," 65 P.S. § 67.708(b)(10) (emphasis added), and did not use the term "reveal." The term reflect means "mirror" or "show," while the term reveal means "to make publicly or generally known" or, in other words, "disclose." Webster's Third New International Dictionary 1908, 1942 (2002). Given the broad meaning of the term reflect, as opposed to reveal, and the fact that the General Assembly chose the term reflect when providing for the predecisional deliberative exception, we must interpret the exception as written.

Scolforo, 65 A.3d at 1101-1102.

Accordingly, the General Assembly's specific use of the word "reflect" in the internal, predecisional deliberation exception of the RTKL signifies that there is no requirement that the deliberated course of action be detailed, set forth, or summarized in a record in order to confer this protection. 65 P.S. § 67.708(b)(10)(i)(A). A record is protected from disclosure even if it reflects the agency's deliberations.

The withheld records are also exempt from production as internal, predecisional deliberative because they memorialized strategies used to develop the successful development of a rulemaking. 65 P.S. § 67.708(b)(10)(i)(B).

The Department also withheld 148 pages of records which consist of emails and records exchanged between program staff with draft outlines of estimates of costs based on information gathered on cost for discussion and evaluation by Department personnel within the rulemaking process. Five pages of records were withheld as notes taken during telephone calls to operators and subcontractors concerning cost estimates related to the rulemaking. None of the records withheld contain a final determination by the Department.

By way of additional information, the Department did not interpret this portion of your request as seeking all the comments received on costs that were submitted to the Department as part of the rulemaking process considered by the Department in determining the cost estimates of the "Environmental Protection Performance Standards at Oil and Gas Well Sites" rulemaking. Outside the scope of this RTKL request, comments received on

the "Environmental Protection Performance Standards at Oil and Gas Well Sites" rulemaking, including comments related to cost, are published on the Independent Regulatory Review Commission's website at http://www.irrc.state.pa.us/regulations/RegSrchRslts.cfm?ID=3052. In addition to its independent research through its "reaching out activities," the Department relied on the cost estimates provided by commentators in formal comments submitted on the proposed and draft-final rulemakings to make its cost estimates as outlined in the Regulatory Analysis Form attached to the final-form rulemaking. Additionally, outside the scope of this rulemaking, the Department is voluntarily providing redacted records related to its independent research of costs associated with the proposed rulemaking.

In conclusions, thirty-three pages of responsive records are enclosed that are directly responsive to your request. The cost of fulfilling your request is **$18.36** ($.25 per page for the duplication of thirty-three pages; $.50 per page for duplication of four redacted pages; and $8.11 for postage).

Please remit payment in this amount by **March 28, 2016,** to the Department at the address listed. Checks should be made out to the Commonwealth of Pennsylvania and also reference the RTKL request number listed above. The remittance should be sent to me. Cash or credit card payment is not accepted.

Further, the failure to pay for records provided in response to a RTKL request to any executive agency will preclude you from obtaining further records from another executive agency, pursuant to the provisions of section 901 of the RTKL and Section IV (D) of the Department's RTKL Policy, published at http://www.dep.pa.gov/Citizens/PublicRecords/RightToKnowLaw/Pages/default.aspx#.VobNGxwo7X4.

Please note that in the Department's discretion, thirty of the thirty-three pages of responsive records are being released to you within the Department's discretion pursuant to 65 P.S. § 67.506(c) of the RTKL. These voluntarily provided records constitute internal, predecisional deliberations of the Department, 65 P.S. § 67. 708(b)(10)(A), or are exempt from production because they contain strategy used to develop the successful development of a rulemaking, 65 P.S. § 67. 708(b)(10)(B). Four pages of voluntarily provided records were redacted as containing personal identification information, specifically, personal email addresses.

You have a right to appeal this response in writing to the Executive Director, Office of Open Records (OOR), Commonwealth Keystone Building, 400 North Street, 4th Floor, Harrisburg, Pennsylvania 17120. If you choose to file an appeal you must do so within 15 business days of the mailing date of this response and send to the OOR:

1) all Department responses;
2) your request; and
3) the reason why you think the Department is wrong in its response.

Also, the OOR has an appeal form available on the OOR website at: http://www.openrecords.pa.gov/Using-the-RTKL/Pages/RTKLForms.aspx#.Voa6lRwo7X5.

Sincerely,

Dawn Schaef

Dawn Schaef
Agency Open Records Officer

Enclosure

cc: RTK CO Legal via email
RTK CO HR, OG, PO via email

DEP Total Filled Complement

YEAR	Salary	Wage	Total
2000	2993	223	3216
2005	2829	152	2981
2010	2610	70	2680
2015	2472	104	2576

DEP Oil & Gas Organizations

YEAR	Salary	Wage	Total
2000	2	0	2
2005	8	0	8
2010	151	1	152
2015	154	0	154

DEP Oil & Gas Jobs

YEAR	Salary	Wage	Total
2000	138	0	138
2005	121	0	121
2010	148	0	148
2015	151	2	153

Wallace, Todd

From: Wallace, Todd
Sent: Monday, September 14, 2015 2:41 PM
To: Repa, Janice
Cc: Sutton, Tina; Perry, Scott (DEP); Ryder, John; Klapkowski, Kurt E; Emlet, Rodney
Subject: Severance Tax funded positions
Attachments: Complement Request - 25 Positions - Severance Tax (1).xlsx

Jan –

As you know, when the Office of Oil and Gas Management prepared its spending plan for FY2015-16 and FY2016-17, we were asked to plan for $5 million in potential revenue to support 25 additional positions within the oil and gas program in the event that the governor's severance tax proposal is passed by the General Assembly. Our original spending plan contemplated the possibility of this additional revenue and identified proposed expenditures in this "growth" scenario. At the time the spending plan was prepared, this office did not identify specific job classifications that would be created in the event of the passage of the severance tax proposal since this was unknown at the time. For budgeting purposes, we estimated $100,000 for salary/benefits associated with each of the 25 positions for a total of $2.5 million in costs. We, likewise, identified "growth" operating and fixed asset expenses that would be anticipated to support these additional 25 positions.

To assist the Bureau of Fiscal Management as it prepares the re-budget, the Office of Oil and Gas Management has prepared the attached list of complement to more accurately identify the 25 positions that would be added to this program in the event of the passage of the severance tax legislation. This list represents our best effort to identify new positions based on current programmatic needs; however, future direction from this Administration coupled with possible change to Departmental/program goals and objectives could affect the future composition of this list.

Should you require any additional information, please feel free to contact me and I will assist.

Todd

Todd M. Wallace | Executive Assistant
Office of Oil and Gas Management
Department of Environmental Protection
Rachel Carson State Office Building
400 Market Street | Harrisburg, PA 17101
Phone: 717.783.9438 | Fax: 717.705.4087
www.depweb.state.pa.us

Position*	Job Title	No. of FTEs	Pay Scale	Fund Center
1	Licensed Professional Geologist	3	8	35882
2	Water Quality Specialist Supervisor	2	8	35882
3	Water Quality Specialist	9	6	35882
4	Oil and Gas Inspector Supervisor	2	8	35882
5	Oil and Gas Inspector	9	7	35882

Nolan, Elizabeth A.

From: [redacted]
Sent: Wednesday, November 13, 2013 4:29 PM
To: Brokenshire, Stephen
Subject: Fw: 78 C costs
Attachments: 78 C Costs.doc

----- Forwarded Message -----
From: [redacted]
To: [redacted]
Sent: Monday, May 13, 2013 3:17 PM
Subject: Re: 78 C costs

Here you go MMDD. I did the best I could. It's very difficult to determine these costs accurately because there are so many variables involved. I included a brief note of explanation with some of them. N.C. ? means I have no clue. The pipeline stuff I could do much with, hopefully Rob will come through in that area. Hope this helps some.

Stranger in a Strange Land

From: [redacted]
To: [redacted]
Sent: Thursday, April 25, 2013 4:43:26 PM
Subject: 78 C costs

ANNEX A
Title 25. Environmental Protection
Part. I. Department of Environmental Protection
Subpart C. Protection of Natural Resources
Article I. Land Resources
CHAPTER 78. OIL AND GAS WELLS

§ 78.15. Application requirements.

(d) The applicant shall provide proof of consultation with the Pennsylvania Natural Heritage Program (PNHP) regarding the presence of a State or Federal threatened or endangered species where the proposed well site or access road is located. If the Department determines, based on PNHP data or other sources, that the proposed well site or access road may adversely impact the species or critical habitat, the applicant shall consult with the Department to avoid or prevent the impact. If the impact cannot be avoided or prevented, the applicant shall demonstrate how the impacts will be minimized in accordance with State and Federal laws pertaining to the protection of threatened or endangered flora and fauna and their habitat.

(e) If an applicant seeks to locate a well on a well site where the applicant has obtained a permit under 25 Pa.Code § 102.5 (relating to permit requirements) and complied with 25 Pa.Code § 102.6(a)(2), the applicant is deemed to comply with subsection (d).

$ $3,000.00 Cost per well site. ***So much of this depends on the specific work that has to be done. If you encounter threatened or endangered species the price goes way up.***

(f) An applicant proposing to drill a well at a location listed in paragraph (1) shall notify the applicable resource agency, if any, in accordance with paragraph (2) and provide the information in paragraph (3) to the Department in the well permit application.

(1) This subsection applies if the proposed well is located:
(i) in or within 200 feet of a publicly owned park, forest, game land or wildlife area.
(ii) in or within the corridor of a state or national scenic river.
(iii) within 200 feet of a national natural landmark.
(iv) in a location that will impact other critical communities. For the purposes of this section other critical communities means special concern species.
(v) within 200 feet of a historical or archeological site listed on the Federal or State list of historic places.
(vi) in the case of an unconventional well, within 1000 feet of a water well, surface water intake, reservoir or other water supply extraction point used by a water purveyor.

(2) The applicant shall notify the public resource agency responsible for managing the public resource identified in paragraph (1), if any. The applicant shall forward by certified mail a copy of the plat identifying the proposed location of the well, well site and access road and information in paragraph (3) to the public resource agency at least 15 days prior to submitting its well permit application to the Department. The applicant shall submit proof of notification with the well permit application. From the date of notification, the public resource agency shall have 15 days to provide written comments to the Department and the applicant on the functions and uses of the public resource and the measures, if any, that the public resource agency recommends the Department consider to avoid or minimize probable harmful impacts to the public resource where the well, well site and access road is located. The applicant may provide a response to the Department to any such comments.

(3) The applicant shall include the following information in the well permit application on forms provided by the Department:
(i) an identification of the public resource.
(ii) a description of the functions and uses of the public resource;
(iii) a description of the measures proposed to be taken to avoid or mitigate impacts, if any.

(4) The information required in paragraph 3 shall be limited to the discrete area of the public resource that may be affected by the well, well site and access road.

(g) If the proposed well, well site or access road poses a probable harmful impact to a public resource, the Department may include conditions in the well permit to avoid or mitigate those impacts to the public resource's current functions and uses. The Department shall consider the impact of any potential permit condition on the applicant's ability to exercise its property rights with regard to the development of oil and gas resources and the degree to which any potential condition may impact or impede the optimal development of the oil and gas resources. The issuance of a permit containing conditions imposed by the Department pursuant to this subsection shall be an action that is appealable to the Environmental Hearing Board. The Department shall have the burden of proving that the conditions were necessary to protect against a probable harmful impact of the public resource.

$2,000.00 Cost per well site. ***Again this depends upon what public resources are and what conditions the Department adds to the well permit.*** **The intial administration costs should not be too high, however, complying with permit conditions could easily be in the tens of thousands.**

§ 78.18. Disposal and enhanced recovery well permits.

(d) All containment practices and on-site processing associated with disposal and enhanced recovery wells shall comply with the requirements of this chapter.

$_____N.C.?_____ Cost per well site.

§ 78.52. Predrilling or prealteration survey.

(g) The operator of an unconventional well must provide written notice to the landowner or water purveyor indicating that the presumption established under section 3218(c) of the act (58 Pa.C.S. § 3218(c)) may be void if the landowner or water purveyor refused to allow the operator access to conduct a predrilling or prealteration survey. Proof of written notice to the landowner or water purveyor shall be provided to the Department for the operator to retain the protections under sections 3218(d)(1)(ii) and 3218(d)(2)(ii) of the act (58 Pa.C.S. §§ 3218(d)(1)(ii) and 3218(d)(2)(ii)). Proof of written notice shall be presumed if provided in accordance with section 3212(a) of the act (58 Pa.C.S. § 3212(a)).

$ 1,000.00 Cost per well site.-

§ 78.52a. Abandoned and orphaned well identification.

(a) Prior to hydraulically fracturing the well, the operator of a gas well or horizontal oil well shall identify the location of orphaned or abandoned wells within 1,000 feet measured horizontally from the vertical well bore and 1000 feet measured from the surface above the entire length of a horizontal well bore in accordance with subsection (b). Prior to hydraulically fracturing the well, the operator of a vertical oil well shall identify the location of orphaned or abandoned wells within 500 feet of the well bore in accordance with subsection (b). For the purposes of this section a gas well is a well which is producing or capable of producing marketable quantities of gas or of gas and oil with a gas-oil ratio of more than 100 MCF per bbl. of oil.

(b) Identification shall be accomplished by conducting the following:
(1) A review the Department's orphaned and abandoned well database;
(2) A review of applicable farm line maps, where accessible; and
(3) Submitting a questionnaire on forms provided by the Department to landowners whose property is within the area identified in subsection (a) regarding the precise location of orphaned and abandoned wells on their property.

$ $9,000.00 Cost per well site.

(c) Prior to hydraulically fracturing a well, the operator shall submit a plat to the Department showing the location and GPS coordinates of orphaned and abandoned wells identified pursuant to subsection (b) and proof of notification that the operators submitted questionnaires pursuant to subsection (b)(3).

$ 2,000.00 _____ Cost per well.

§ 78.55 Planning and emergency response.

(a) Persons conducting oil and gas operations shall prepare and implement site specific PPC plans according to the requirements in 25 Pa.Code § 91.34 and 102.5(l).

(b) In addition to the requirements in subsection (a), the well operator shall prepare and develop a site specific PPC plan prior to storing, using, generating or transporting regulated substances to, on or from a well site from the drilling, alteration, production, plugging or other activity associated with oil and gas wells.

(c) The unconventional well operator's PPC plan must describe the containment practices to be utilized and the area of the well site where containment systems will be employed as required in section 78.64a. The PPC plan shall 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.

$ 2,000.00 _____ Cost per well site.

§ 78.56. Temporary storage.

(5) For unconventional well sites, unless an individual is continuously present at the well site, a fence or fences shall completely surround all pits to prevent unauthorized acts of third parties and damage caused by wildlife.

$ 5,000.00 _____ Cost per well site. 600 liner ft @ $6.00 per foot + Maintenance and tear down costs.

(6) Unless an individual is continuously present at the well site, operators shall 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. Tanks storing freshwater, fire prevention materials and spill response kits are excluded from the requirements of this paragraph.

$ 2,000.00 _____ Cost per well site.

(7) The operator of an unconventional well site shall display a sign on or near the tank or other approved storage structure identifying the contents, and containing an appropriate warning of the contents such as flammable, corrosive or a similar warning.

$ 1,000.00 Cost per well site.

(8) (iv) Adjoining sections of liners shall be sealed together to prevent leakage in accordance with the manufacturer's directions. The integrity of all seams of the adjoining sections of liner shall be tested prior to use. Results of the tests shall be available upon request.

$ 2,000.00 Cost per well site. ***Based on the average size liner.***

(10) The pit shall be constructed so that the liner subbase is smooth, uniform and free from debris, rock and other material that may puncture, tear, cut or otherwise cause the liner to fail. The pit must be structurally sound and the interior slopes of the pit must have a slope no steeper than 2 horizontal to 1 vertical.

$ 3,000.00 Cost per well site. ***Increasing the interior slopes to 2 H : 1V will increase the overall size of the pit. The subbase being properly prepared is already a requirement. Additional costs based upon size increase only.***

(11) The bottom of the pit shall be at least 20 inches above the seasonal high groundwater table, unless the operator obtains approval under subsection (b) for a pit that exists only during dry times of the year and is located above groundwater. The operator of an unconventional well shall determine that the pit bottom is at least 20 inches above the seasonal high groundwater table prior to using the pit. The determination shall be made by a soil scientist or other similarly trained person using accepted and documented scientific methods. The individual's determination shall contain a statement certifying that the pit bottom is at least 20 inches above the seasonal high groundwater table according to observed field conditions. The name, qualifications and statement of the individual making the determination and the basis of the determination shall be provided to the Department upon request.

$ 1,500.00 Cost per well site.

(17) Condensate, whether separated or mixed with other fluids, shall not be stored in any open top structure or pit. Tanks used for storing or separating condensate during well completion shall be monitored and shall have controls to prevent vapors from exceeding the lower explosive limits of the condensate outside the tank. Tanks used for storing or separating condensate shall be grounded.

$ 10,000.00 Cost per well site.- ***Cost of additional equipment and monitoring during flowback.***

§ 78.57. Control, storage and disposal of production fluids.

(c) Secondary containment capable of preventing tank contents from entering waters of the Commonwealth is required for all new, refurbished or replaced tanks or other aboveground containment structures approved by the Department, including their associated manifolds, that contain brine and other fluids produced during operation of the well. If one tank in a series of tanks is added, refurbished or replaced, secondary containment is required for the entire series of tanks. The secondary containment area provided by dikes or other methods of secondary containment open to the atmosphere shall have containment capacity sufficient to hold the volume of the largest single tank, plus an additional 10% of volume for precipitation. Compliance with § 78.64 (relating to containment around oil and condensate tanks) or using double walled tanks capable of detecting a leak in the primary container shall fulfill the requirements in this subsection.

$____10,000.00_____Cost per well site.

(d) Tanks, series of tanks or other above ground storage structures approved by the Department 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. Tanks that are manifolded together shall be designed in a manner to prevent the uncontrolled discharge of multiple manifolded tanks.

$_____2,000.00_____ Cost per well site.

(e) Underground or partially buried storage tanks may not be used to store brine or other fluids produced during operation of the well unless approved by the Department. Existing underground or partially buried storage tanks shall be removed within 3 years of the effective date of this subsection. A well operator utilizing underground or partially buried storage tanks as of the effective date of this section shall provide the Department with a list of the well sites where the underground or partially buried storage tanks are located and schedule for removal of the tanks within six months from the effective date of this subsection.

$____10,000.00_____ Cost per well site. ***Cost includes the removal of old tanks and the installation of new ones. The size of the tanks would be the most significant cost variable.***

(f) All new, refurbished or replaced tanks that store brine or other fluid produced during operation of the well must comply with the applicable corrosion control requirements in the Department's storage tanks regulations at 25 Pa. Code §§ 245.531-534.

$_____N.C.?_____ Cost per well site.

(g) All new, refurbished or replaced tanks storing brine or other fluids produced during operation of the well shall be reasonably protected from unauthorized acts of third parties. Unless the tank is surrounded by a fence, tank valves and access lids shall utilize locks, open end plugs or removable handles and ladders on tanks shall be retractable or other measures that prevent access by third parties.

$_____$3,000.00_____ Cost per well site. ***Cost will vary greatly depending upon the production set-up.***

§ 78.58 Onsite processing.

(a) The operator may request approval by the Department to process fluids generated by the development, drilling, stimulation, alteration, operation or plugging of oil or gas wells at the well site where the fluids were generated or at the well site where all of the fluid is intended to be beneficially used to develop, drill or stimulate a well. The request shall be submitted on forms provided by the Department and demonstrate that the processing operation will not result in pollution of land or waters of the Commonwealth.

(b) Approval from the Department is not required for the following activities conducted at a well site or centralized impoundment permitted under § 78.59c:
(1) mixing fluids with freshwater;
(2) aerating fluids; or
(3) filtering solids from fluids.

(c) The operator may request to process drill cuttings only at the well site where those drilling cuttings were generated, by submitting a request to the Department for approval. The request shall be submitted on forms provided by the Department and demonstrate that the processing operation will not result in pollution of land or waters of the Commonwealth.

(d) Processing residual waste generated by the development, drilling, stimulation, alteration, operation or plugging of oil or gas wells other than as provided for in subsections (a) and (b) shall comply with the requirements of the Solid Waste Management Act.

(e) Processing of fluids in a manner approved pursuant to subsection (a) shall be deemed to be approved at subsequent well sites provided the operator notifies the Department of location of the well site where the processing will occur prior to the commencement of processing operations. This notice shall be submitted electronically to the Department through its website and include the date activities will commence.

(f) Sludges, filter cake or other solid waste remaining after the processing or handling of fluids pursuant to subsections (a) or (b), including solid waste mixed with drill cuttings, shall be characterized pursuant to 25 Pa. Code § 287.54 before the solid waste leaves the well site.

$____NC?_____ Cost per well.

§ 78.59b. Freshwater impoundments.

(a) In addition to meeting the requirements of 25 Pa. Code § 78.59a, freshwater impoundments shall comply with this section.

(b) A well operator that constructed a freshwater impoundment shall register the location of the freshwater impoundment within 60 days of the effect of this section by providing the Department, in writing, with the GPS coordinates, township and county where the freshwater impoundment is located. A well operator shall register the location of a new freshwater impoundment prior to construction. Registration of the freshwater impoundment may be transferred to another operator. Registration transfers shall utilize forms provided by the Department.

(c) Freshwater impoundments shall be constructed with a synthetic impervious liner.

$___\$1,000.00_____ Cost per impoundment.

(d) Unless an individual is continuously present at a freshwater impoundment, a fence shall completely surround the freshwater impoundment to prevent unauthorized acts of third parties and damage caused by wildlife.

$___\$10,000.00_____ Cost per impoundment. ***Cost will vary greatly depending upon the type of the fencing used. Costs for removal must also be included.***

(e) The bottom of the impoundment shall be at least 20 inches above the seasonal high groundwater table. The applicant may maintain the required separation distance of 20 inches by artificial means such as an under-drain system throughout the lifetime of the impoundment. In no case shall the regional groundwater table be affected. The operator shall document the depth of the seasonal high groundwater table, the manner in which the depth of the seasonal high groundwater table was ascertained, the distance between the bottom of the impoundment and the seasonal high groundwater table, and the depth of the regional groundwater table if the separation between the impoundment bottom and seasonal high groundwater table is maintained by artificial means. The operator shall submit records demonstrating compliance with this subsection to the Department upon request.

$___\$3,000.00_____ Cost per impoundment.

(f) Freshwater impoundments shall be restored by the operator that the impoundment is registered to by removing excess water and the synthetic liner and returning the site to approximate original conditions, including preconstruction contours, and can support the original land uses to the extent practicable within nine months of completion of drilling the last well serviced by the impoundment. A two-year restoration extension may be requested pursuant to section 3216(g) of the act (58 Pa.C.S. § 3215(g)). If written consent is obtained from the landowner, the requirement to return the site to approximate original contours may be waived by the Department if the liner is removed from the impoundment.

$_____ Cost per impoundment.

(g) Prior to storing mine influenced water in a freshwater impoundment, the operator shall develop a mine influenced water storage plan and submit it to the Department for approval.

$_____ Cost per impoundment.

(1) The mine influenced water storage plan shall be submitted on forms provided by the Department and shall include the following:
(i) a demonstration that the escape of the mine influenced water stored in the freshwater impoundment will not result in air, water or land pollution or endanger persons or property and include;
(ii) a procedure and schedule to test the mine influenced water. This testing shall be conducted at the source prior to storage in the impoundment; and
(iii) a records retention schedule for the mine influenced water test results.

(2) An operator with an approved mine influenced water storage plan shall maintain records of all mine influenced water testing prior to storage. These records shall be made available to the Department upon request.

$ $4,000.00 Cost per impoundment.

(h) The Department may require the operator to test water sources proposed to be stored in a freshwater impoundment prior to storage.

$ $2,000.00 Cost per impoundment.

§ 78.61. Disposal of drill cuttings.

(a)(9) The bottom of the pit is a minimum of 20 inches above the seasonal high groundwater table. The well operator shall determine that the pit bottom is at least 20 inches above the seasonal high groundwater table prior to using the pit. The determination shall be made by a soil scientist or other similarly trained person using accepted and documented scientific methods. The individual's determination shall contain a statement certifying that the pit bottom is at least 20 inches above the seasonal high groundwater table according to observed field conditions. The name, qualifications and statement of the individual making the determination and the basis of the determination shall be provided to the Department upon request.

$_____$1,500.00_____ Cost per well site.

§ 78.64. Containment around oil and condensate tanks.

(a) If an owner or operator uses a tank with a capacity of at least 660 gallons or tanks with a combined capacity of at least 1,320 gallons to contain oil or condensate produced from a well, the owner or operator shall construct and maintain a dike or other method of secondary containment which satisfies the requirements under 40 CFR 112 (relating to oil pollution prevention) around the tank or tanks which will prevent the tank contents from entering waters of this Commonwealth.

$__$0.00_____ Cost per well site. ***Already a requirement. Cost will vary greatly with the size of the production area.***

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

(a) This section shall only apply to unconventional well sites.

(b) Well sites shall be designed and constructed using containment systems and practices that prevent spills of regulated substances to the ground surface and to prevent spills from leaving the well site.

(c) All regulated substances, including solid wastes and other regulated substances in equipment or vehicles, shall be managed within a containment system. This subsection does not apply to fuel stored in equipment or vehicle fuel tanks unless the equipment or vehicle is being refueled at the well site.

(d) Pits and centralized impoundments that comply with this Chapter are deemed to meet the requirements of this section.

(e) Containment systems shall meet all of the following:

(1) Be used on the 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 including drilling mud, drilling mud additives, hydraulic oil, diesel fuel, hydraulic fracturing additives or flowback are brought onto or generated at the well site.
(2) Have a coefficient of permeability no greater than 1 x 10-10 cm/sec.
(3) The physical and chemical characteristics of all liners, coatings or other materials used as part of the system, that could potentially come into direct contact with regulated substances being stored, shall be compatible with the regulated substance and be resistant to physical, chemical and other failure during handling, installation and use. Liner compatibility shall satisfy ASTM Method D5747 Compatibility Test for Wastes and Membrane Liners or other standards as approved by the Department.

(f) *Secondary containment:* An operator shall utilize secondary containment when storing additives, chemicals, oils or fuels. The secondary containment shall have sufficient containment capacity to hold the volume of the largest container within the secondary containment area plus 10% to allow for precipitation, unless the container is equipped with individual secondary containment such as a double walled tank. Tanks that are manifolded together shall be designed in a manner to prevent the uncontrolled discharge of multiple manifolded tanks. A well site liner that is not used in conjunction with other containment systems does not constitute secondary containment for the purpose of this subsection.

(g) Subsurface secondary containment systems may be employed at the well site. Subsurface secondary containment shall meet the following requirements:
(1) Subsurface secondary containment systems shall have a coefficient of permeability of no greater than 1 x 10-10 cm/sec with sufficient strength and thickness to maintain the integrity of the containment system. The thickness of a subsurface containment system shall be at least 30 mils. Adjoining sections of the subsurface containment system shall be sealed together, in accordance with the manufacturer's directions, to prevent leakage. All seams of the adjoining sections shall have their integrity tested prior to being covered.
(2) Be designed to allow for the management or removal of stormwater.
(3) Be designed and installed in a manner that prevents damage to the system by the sub-base or the movement of equipment or other activities on the surface.
(4) Not be used to store regulated substances.
(5) A written Standard of Operational Procedure for the inspection, maintenance and repair of the subsurface secondary containment system shall be included in the preparedness, prevention and contingency plan.

(h) All surface containment systems shall be inspected weekly to ensure integrity. If the containment system is damaged or compromised, the well operator shall repair the containment system as soon as practicable. The well operator shall maintain records of any repairs until the well site is restored. Stormwater shall be removed as soon as possible and prior to the capacity of secondary containment being reduced by 10% or more.

(i) Regulated substances that escape from primary containment or are otherwise spilled onto a containment system shall be removed as soon as possible. After removal of the regulated

substances the operator shall inspect the containment system. A Department approved leak detection system capable of rapidly detecting a leak shall satisfy the requirement to inspect the integrity of a subsurface containment system. Groundwater monitoring wells shall not constitute a leak detection system for the purpose of this subsection. If the containment system did not completely contain the material, the operator shall notify the Department and remediate the affected area in accordance with § 78.66.

(j) Stormwater that comes into contact with regulated substances stored within the secondary containment area shall be managed as residual waste.

(k) Inspection reports and maintenance records shall be available at the well site for review by the Department.

(l) Documentation of chemical compatibility of containment systems with material stored within the system shall be provided to the Department upon request.

$ 100,000.00 Cost of containment per well site. ***I know a lot about this one. The cost varies based on the size of the site and the containment systems used. When you look at everything from subbase prep, to liner material, to the construction of Berming systems, renting rig mats or fiber grate, etc… 100 grand is a good overall ballpark figure.***

§ 78.65. Site restoration.

(d) *Restoration after drilling* — Within nine months after completion of drilling a well, the owner or operator shall restore the well site, remove or fill all pits used to contain produced fluids or residual wastes and remove all drilling supplies, equipment and containment systems not needed for production. When multiple wells are drilled on a single well site, post drilling restoration is required within nine months after completion of drilling all permitted wells on the well site or 30 days after the expiration of all existing well permits on the well site, whichever occurs later in time. Drilling supplies and equipment not needed for production may only be stored on the well site if express written consent of the surface landowner is obtained and the supplies or equipment are maintained in accordance with § 78.64a.
(1) An area is restored under this subsection if the following are met:
(i) All permanent post construction stormwater control features as identified in the PCSM plan or site restoration plan are in place consistent with the requirements in 25 Pa. Code § 102.8.
(ii) Remaining impervious areas are minimized. Impervious areas include areas where the soil has been compacted, areas where the soil has been treated with amendments to firm or harden the soil and areas where soil is underlain with an impermeable liner.
(iii) All areas of the site not needed to safely operate the well are restored to approximate original conditions, including preconstruction contours, and can support the original land uses to the extent practicable. The areas needed to safely operate the well include to the following:

(A) Areas used for service vehicle and rig access.
(B) Areas used for storage tanks and secondary containment facilities.
(C) Areas used for wellhead(s) and appurtenant processing facilities.
(D) Area used for any necessary safety buffer limited to the area surrounding equipment that is physically cordoned off to protect the facilities.
(E) Area used to store any supplies or equipment consented to by the surface landowner.
(F) Area used for operation and maintenance of long-term PCSM best management practices.
(iv) Earth disturbance associated with oil and gas activities that are not included in an approved site restoration plan, and other remaining impervious surfaces, shall comply with all post construction stormwater management requirements in 25 Pa. Code Chapter 102.
(v) The site is permanently stabilized according to 25 Pa. Code § 102.22(a).

$ 0.00 Cost per well site. ***Restoration is already required the only real change here are PCSM BMP that are already required by 102.***

(2) The restoration period in this subsection may be extended by the Department for an additional period of time, not to exceed two years, upon demonstration by the well owner or operator that:
(i) the extension will result in less earth disturbance, increased water reuse or more efficient development of the resources; or
(ii) site restoration cannot be achieved due to adverse weather conditions or a lack of essential fuel, equipment or labor.
(3) The demonstration under paragraph (2) shall be submitted on forms provided by the Department six months after the completion of drilling, for approval by the Department. The demonstration must include all of the following:
(i) A site restoration plan that shall provide for:
(A) The timely removal or fill of all pits used to contain produced fluids or residual wastes;
(B) The removal of all drilling supplies and equipment not needed for production, including containment systems;
(C) The stabilization of the well site that shall include interim post construction storm water management best management practices in compliance with 25 Pa. Code §102.8 including 25 Pa. Code §§ 102.8(a)–(m); or
(D) Other measures to be employed to minimize accelerated erosion and sedimentation in accordance with The Clean Streams Law.
(E) A minimum uniform 70% perennial vegetative cover over the disturbed area, with a density capable of resisting accelerated erosion and sedimentation, or a BMP which permanently minimizes accelerated erosion and sedimentation.
(F) Return the portions of the site not occupied by production facilities or equipment to approximate original conditions, including preconstruction contours, and can support the original land uses to the extent practicable.
(4) Written consent of the landowner on forms provided by the Department satisfies the restoration requirements of this section provided the operator develops and implements a site restoration plan that complies with paragraph 3(i)(A)-(E) and all PCSM requirements in 25 Pa. Code Chapter 102.

$ 1000.00 Cost per well site. ***Already required by the 2012 O&G Act. Restoration extensions save operators money. Minor expenses may be incurred while satisfying additional conditions that must be met to apply for an extension.***

(e) *Restoration after plugging*—Within nine months after plugging a well, the owner or operator shall remove all production or storage facilities, supplies and equipment and restore the well site to approximate original conditions, including preconstruction contours, and can support the original land uses to the extent practicable.

$ $0.00 Cost per well site. ***Already required.***

(f)(6) The name, qualifications and basis for determination that the bottom of a pit used for encapsulation is at least 20 inches above the seasonal high groundwater table.

$ < 1,000.00 Cost per well site.

§ 78.66. Reporting and remediating releases.

(a) *Scope* - This section applies to reporting and remediating spills or releases of regulated substances on or adjacent to well sites and access roads.

(b) *Reporting releases*

(1) An operator or responsible party shall report the following spills and releases of regulated substances to the Department in accordance with paragraph (2):
(i) A spill or release of a regulated substance causing or threatening pollution of the waters of this Commonwealth, [shall comply with the following reporting and corrective action requirements: of § 91.33 (relating to incidents causing or threatening pollution).]
(ii) A spill or release of 5 gallons or more of a regulated substance over a 24-hour period that is not completely contained by a containment system.
(2) In addition to the notification requirements of 25 Pa. Code § 91.33, the operator or responsible party shall contact the appropriate regional Department office by telephone or call the Department's statewide toll free number 1-800-541-2050 as soon as practicable, but no later than 2 hours after discovering the spill or release. To the extent known, the following information shall be provided:
(i) The name of the person reporting the incident and telephone number where that person can be reached.
(ii) The name, address and telephone number of the responsible party.
(iii) The date and time of the incident or when it was discovered.

(iv) The location of the incident, including directions to the site, GPS coordinates or the 911 address, if available.
(v) A brief description of the nature of the incident and its cause, what potential impacts to public health and safety or the environment may exist, including any available information concerning the contamination of surface water, groundwater or soil.
(vi) The estimated weight or volume of each regulated substance spilled or released.
(vii) The nature of any injuries.
(viii) Remedial actions planned, initiated or completed.
(3) Upon the occurrence of any spill or release, the operator or responsible party shall take necessary corrective actions to:
(i) Prevent the regulated substance from reaching the waters of the Commonwealth.
(ii) Prevent damage to property.
(iii) Prevent impacts to downstream users of waters of the Commonwealth.
(4) The Department may immediately approve temporary emergency storage or transportation methods necessary to prevent or mitigate harm to the public health, safety or the environment. Storage may be at the site of the incident or at a site approved by the Department.
(5) After responding to a spill or release, the operator shall decontaminate equipment used to handle the regulated substance, including storage containers, processing equipment, trucks and loaders, before returning the equipment to service. Contaminated wash water, waste solutions and residues generated from washing or decontaminating equipment shall be managed as residual waste.

$____500.00_____ Cost per incident. ***Most of this is already required. Cost only includes additional administrative costs (staff time, etc…)***

(c) *Remediating releases* - Remediation of an area affected by a spill or release is required. The operator or responsible party must remediate a release in accordance with one of the following:
(1) Spills or releases to the ground of less than 42 gallons at a well site that do not impact or threaten to pollute of waters of the Commonwealth may be remediated by removing the soil visibly impacted by the release and properly managing the impacted soil in accordance with the Department's waste management regulations. The operator or responsible party shall notify the Department of its intent to remediate a spill or release in accordance with this paragraph at the time the report of the spill or release is made. Completion of the cleanup should be documented through the process outlined in 25 Pa.Code § 250.707(b)(1)(iii)(B) (relating to statistical tests).

$_____ Cost per incident. ***Spills have to be cleaned up anyway so I'm not sure what the additional costs would be.***

(2) For spills or releases to the ground of more than 42 gallons or that impact or threaten pollution of waters of the Commonwealth, the operator or responsible person may satisfy the requirements of this subsection by demonstrating attainment of one or more of the standards established by Act 2 and 25 Pa.Code Chapter 250 (relating to administration of land recycling program).

$_____ Cost per incident. ***Additional cost too difficult to determine. Spills have to be cleaned up anyway whether or not you follow Act II or the Alternative Method.***

(3) For releases of more than 42 gallons or that impact or threaten pollution waters of the Commonwealth, as an alternative to (2), the responsible party may remediate a spill or release using the Act 2 background or Statewide health standard in the following manner:
(i) Within 15 days of the spill or release, the operator or responsible party shall provide an initial written report that includes, to the extent that the information is available, the following:
(A) The regulated substance involved,
(B) The location where the spill or release occurred,
(C) The environmental media affected,
(D) Impacts to water supplies, buildings or utilities, and
(E) Interim remedial actions planned, initiated or completed.
(ii) The initial report shall also include a summary of the actions the operator or responsible party intends to take at the site to address the spill or release such as a schedule for site characterization, to the extent known, and the anticipated timeframes within which it expects to take those actions. After the initial report, any new impacts identified ordiscovered during interim remedial actions or site characterization shall also be reported in writing to the Department within 15 days of their discovery.
(iii) Within 180 days of the spill or release, the operator or responsible party must perform a site characterization to determine the extent and magnitude of the contamination and submit a site characterization report to the appropriate Department Regional Office describing the findings. The report shall include a description of any interim remedial actions taken. For a background standard remediation, the site characterization shall contain information required by 25 Pa.Code § 250.204(b)-(e) (relating to final report). For a Statewide health standard remediation, the site characterization shall contain information required by 25 Pa.Code § 250.312(a) (relating to final report).
(iv) This report may be a final remedial action report if the interim remedial actions meets all of the requirements of an Act 2 background or Statewide health standard remediation or combination thereof. Remediation conducted under this section shall not be required to meet the notice and review provisions of these standards except as described in this section.
(v) If the site characterization indicates that the interim remedial actions taken did not adequately remediate the release the operator or responsible party must develop and submit a remedial action plan to the appropriate Regional Office of the Department for approval. The plan is due within 45 days of submission of the site characterization to the Department. Remedial action plans should contain the elements outlined in 25 Pa.Code § 245.311(a) (relating to remedial action plan).
(vi) Once the remedial action plan is implemented, the responsible party must submit a final report to the appropriate Department Regional Office for approval. The Department will review the final report to ensure that the remediation has met all the requirements of the background or Statewide health standard or combination thereof, except the notice and review provisions. Relief

from liability will not be available to the responsible party, property owner or person participating in the cleanup.

$_____ Cost per incident.

(vii) An operator or responsible party remediating a release pursuant to this paragraph may elect to utilize Act 2 at any time.

§ 78.67. Borrow pits.

(a) An operator who owns or controls a borrow pit that does not require a permit pursuant to the Noncoal Surface Mining Conservation and Reclamation Act pursuant to the exemption in 3273.1(b) of the act (58 Pa. C.S. § 3273.1(b)) relating to noncoal borrow areas for oil and gas well development, shall operate, maintain and reclaim the borrow pit in accordance with the performance standards established in 25 Pa. Code Chapter 77 Subchapter I, 25 Pa. Code Chapter 102 and other applicable laws.

(b) Operators shall register the location of their existing borrow pits within 60 days of the effective date of this section by providing the Department, in writing, with the GPS coordinates, township and county where the borrow pit is located. The operator shall register the location of a new borrow pit prior to construction.

(c) Borrow pits used for the development of oil and gas well sites and access roads that no longer meet the conditions under section 3273.1 of the act (58 Pa.C.S. § 3273.1) shall meet one of the following:
(1) be restored within nine months after completion of drilling all permitted wells on the well site or 30 days after the expiration of all existing well permits on the well site, whichever occurs later in time.
(2) obtain a noncoal surface mining permit for its continued use, unless relevant exemptions apply pursuant to the Noncoal Surface Mining Conservation and Reclamation Act and regulations promulgated thereunder. A two-year extension of the restoration requirement may be approved pursuant to section 78.65(d).

$____$5000,00_____ Cost per borrow pit. ***This cost will vary greatly depending upon the size of the pit.***

§ 78.68. Oil and gas gathering lines.

(b) Highly visible flagging, markers or signs shall be used to identify the shared boundaries of the limit of disturbance, wetlands and locations of threatened or endangered species habitat, prior to land clearing. The flagging, markers or signs shall be maintained throughout earth disturbance activities, and restoration or PCSM activities.

$ $1,000.00 Average cost per project.

(h) All buried metallic gathering lines shall be installed and placed in operation in accordance with 49 CFR Pt. 192 or 195 (relating to the requirements for corrosion control).

$_____ Average cost per project.

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

(b) Prior to commencement of any horizontal directional drilling activity, the directional drilling operator shall develop a PPC plan pursuant to 25 Pa. Code § 102.5(l) (relating to permit requirements). The PPC plan shall include 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 PPC plan must be present on site during drilling operations and made available to the Department upon request.

$ $1000.00 Average cost per project.

(g) Horizontal directional drilling operations shall be monitored for pressure and loss of drilling fluid returns. Bodies of water and watercourses over and adjacent to horizontal directional drilling operations shall also be monitored for any signs of drilling fluid discharges. Monitoring shall be in accordance with the PPC Plan.

$_____ Average cost per project. ***Ask Rob on all the pipeline stuff.***

(h) Horizontal directional drilling activities shall not result in a discharge of drilling fluids to waters of the Commonwealth. If a discharge occurs during horizontal directional drilling activities, the drilling operator shall immediately implement the contingency plan developed pursuant to subsection (b).

$_____ Average cost per project.

(i) When a drilling fluid discharge or loss of drilling fluid circulation is discovered, the loss or discharge shall be immediately reported to the Department, and the operator shall request an emergency permit pursuant to 25 Pa. Code § 105.64 (relating to emergency permits), if necessary.

$_____ Average cost per project.

(k) Horizontal directional drilling fluid returns and drilling fluid discharges shall be contained, stored and recycled or disposed of in accordance with 25 Pa. Code Article IX (relating to residual waste management).

$_____ Average cost per project if fluids disposed.

$_____ Average cost per project if fluids recycled.

§ 78.68b. Temporary pipelines for oil and gas operations.

(a) Temporary pipelines shall meet applicable requirements in 25 Pa. Code Chapters 102 (relating to erosion and sediment control) and Chapter 105 (relating to dam safety and waterway management).

$_____ Average cost per project.

(d) The section of a temporary pipeline crossing over a watercourse or body of water, except wetlands, shall not have joints or couplings. Temporary pipeline crossings over wetlands shall utilize a single section of pipe to the extent practicable. Shut off valves shall be installed on both sides of the temporary crossing.

$_____ Average cost per project.

(e) In addition to the requirements of subsection (c), temporary pipelines used to transport fluids other than fresh ground water, surface water, water from water purveyors or approved sources, shall have shut off valves, check valves or other method of segmenting the pipeline placed at designated intervals, to be determined by the pipeline diameter, that prevent the discharge of no more than 1000 barrels of fluid. Elevation changes that would effectively limit flow in the event of a pipeline leak shall be taken into consideration when determining the placement of shut off valves and be considered effective flow barriers.

$_____ Average cost per project.

(f) Highly visible flagging shall be placed at regular intervals, no greater than 75 feet, along the entire length of the temporary pipeline.

$_____ Average cost per project.

(g) Temporary pipelines shall be pressure tested prior to being first placed into service and after the pipeline is moved or altered. A passing test is holding 125% of the anticipated maximum pressure for two hours. Leaks or other defects discovered during pressure testing shall be repaired prior to use.

$_____ Average cost per project.

(i) Temporary pipelines shall be inspected prior to and during each use. Inspection dates and any defects and repairs to the temporary pipeline shall be documented and made available to the Department upon request.

$_____ Average cost per project.

(j) Temporary pipelines not in use for more than seven days shall be emptied and depressurized.

$_____ Average cost per project.

(m) An operator must keep records regarding the location of all temporary pipelines, the type of fluids transported through those pipelines, and the approximate period of time that the pipeline was installed. Such records must be made available to the Department upon request.

$_____ Average cost per project.

§78.69. Water management plans.

(a) *WMPs for unconventional well operators.* An unconventional well operator shall obtain a Department approved WMP pursuant to section 3211 (m) of the act (58 Pa. C.S. § 3211(m)) prior to withdrawal or use of water sources for drilling or completing an unconventional well.

$ 3,000.00 Cost per Water Plan.

(b) *Implementation.* The requirements imposed by the Susquehanna River Basin Commission pertaining to:
(1) posting of signs at water withdrawal locations,
(2) monitoring of water withdrawals or purchases,

(3) reporting of withdrawal volumes, in-stream flow measurements and water source purchases and,
(4) record keeping shall be implemented in the Ohio River Basin. Reports required in all river basins of the Commonwealth shall be submitted electronically to the Department.

$ 5000.00 Cost per Water Plan.

(c) *Reuse plan.* An unconventional well operator submitting a WMP application shall develop a reuse plan for fluids that will be used to hydraulically fracture wells. A wastewater source reduction strategy in compliance with 25 Pa. Code Chapter 95.10(b) will satisfy the reuse plan requirement. An unconventional well operator shall make the reuse plan available for review by the Department upon request.

$ 2000.00 Cost per Water Plan.

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

(a) Road-spreading of brine from oil and gas wells for dust suppression and road stabilization shall only be conducted pursuant to a plan approved by the Department and shall not result in pollution of the waters of the Commonwealth. Only production brines from conventional wells, not including coalbed methane wells, may be used for dust suppression and road stabilization pursuant to this section. The use of drilling, hydraulic fracture stimulation flowback, plugging fluids, or production brines mixed with well servicing or treatment fluids, except detergents, may not be used for dust suppression and road stabilization.

(b) Road-spreading of brine for dust control and road stabilization shall only be conducted on unpaved roads.

(c) Road-spreading plans shall be submitted annually to the Department for approval and shall include the following:
(1) The name, address and telephone number of the plan applicant and of each person who will conduct the actual road-spreading.
(2) The license plate number of each road-spreading truck.
(3) An original signed and dated statement from the person that owns or maintains the roads where road-spreading will be conducted authorizing the use of brine on roads and that that person will supervise the frequency of road-spreading.
(4) A national wetland inventory map identifying the following:
(i) roads where the road-spreading be conducted,
(ii) any brine storage areas not located on a well site,
(iii) bodies of water and watercourses within 150 feet of the roads identified in (i).
(5) A description of how road-spreading will be conducted, including the equipment to be used and the method for controlling the rate of application of the brine.

(6) The proposed rate and frequency of application.
(7) The name of each well and the associated geologic formation from which the brine is produced.
(8) A chemical analysis of the brine using parameters provided by the Department. A representative sample of the brine may be used, provided that the operator demonstrates that the representative sample is equivalent to the brine being used for road-spreading.

(d) Plans approved under this section will expire on December 31st of each year.

(e) Road-spreading shall be conducted according to the following:

(1) The application of production brine to unpaved roads shall be performed in accordance with the Department approved plan.
(2) The brine shall only be applied at a rate and frequency necessary to suppress dust and stabilize the road, but in no event at a rate or frequency greater than the rate and frequency contained in the approved plan.
(3) The road-spreading shall prevent direct infiltration to groundwater.
(4) Brine shall not enter bodies of water or water courses.

(f) Application rates: The road shall initially be spread at a rate up to one-half gallon per square yard. The road shall subsequently be spread at a rate of up to one-third gallon per square yard. The application rate for race tracks and mining haul roads should be determined for each site and shall not exceed one gallon per square yard.

(g) Requirements for road-spreading. Road-spreading shall meet the following:
(1) Free oil shall be separated from the brine before spreading.
(2) Brine shall not be applied within 150 feet of bodies of water or watercourses.
(3) Brine must be spread by use of a spreader bar with shut off controls in the cab of the truck.
(4) Brine shall not be spread on roads or sections of roads which have a grade in excess of ten percent (10%).
(5) Brine shall not be spread on wet or frozen roads, during precipitation events, or when precipitation is imminent.

(h) Trucks utilized to spread brine shall have signs identifying plan applicant's name and business address on both sides of the vehicle. The signs shall have lettering that is at least six inches in height.
(i) A copy of the current Department approved road-spreading plan shall be kept in the road-spreading vehicle any time road-spreading is being conducted and shall be made available to the Department upon request.

(j) Except for storage at the well site, all storage of brine shall be in tanks in a manner that complies with the requirements set forth in 25 Pa. Code Chapter 299.

(k) The Department shall be notified at least 24 hours before road-spreading will begin. This notice shall be submitted electronically to the Department through its website and include the

date the road-spreading will occur and where the activity will occur. If the date of road-spreading changes, the operator shall re-notify the Department in accordance with this paragraph.

(l) The person identified on the road-spreading plan shall submit a monthly report to the Department on forms provided by the Department listing the locations, frequency and amounts of brine spread during the previous month. Monthly brine spreading reports must be received by the Department on the 15th day of the month that follows the month the brine was spread. These reports must be submitted to the Department on a monthly basis even if no road-spreading of brine took place during the previous month.

(m) Any changes to the approved road-spreading plan must be submitted to the Department for approval. Approval must be obtained from the Department in writing prior to deviating from the plan or implementing any revisions to the plan.

(n) Failure to comply with this section may result in the Department rescinding the plan approval.

(o) Persons conducting road-spreading of brine for dust control and road stabilization activities shall be deemed to have a residual waste permit by rule if those activities comply with the requirements of this section.

$_____ Annual cost savings per well site vs. disposal of brine.

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

(a) Use of brine from oil and gas wells for pre-wetting, anti-icing and de-icing shall only be conducted pursuant to a plan approved by the Department and shall not result in pollution of the waters of the Commonwealth. Only production brines from conventional wells, not including coalbed methane wells or wells drilled in hydrogen sulfide areas, may be used for pre-wetting, anti-icing and de-icing pursuant to this section. The use of drilling, hydraulic fracture stimulation flowback, plugging fluids, or production brines mixed with well servicing or treatment fluids, except detergents, may not be used for pre-wetting, anti-icing and de-icing activities.

(b) Use of brine for pre-wetting, anti-icing and de-icing shall only be conducted on paved roads to address winter driving conditions.
(c) Plans required by subsection (a) shall be submitted annually to the Department for approval and and shall include the following:
(1) The name, address and telephone number of the plan applicant and of each person who will conduct the actual road-spreading.
(2) The license plate number of each road-spreading trucks.
(3) An original signed and dated statement from the person that owns or maintains the roads where road-spreading will be conducted authorizing the use of brine on roads and that that person will supervise the frequency of road-spreading.
(4) A national wetland inventory map identifying the following:

(i) roads where the road-spreading be conducted,
(ii) any brine storage areas not located on a well site,
(iii) bodies of water and watercourses within 150 feet of the roads identified in (i).
(5) A description of how the brine will be applied including the equipment to be used and the method for controlling the rate of application of the brine.
(6) The proposed rate and frequency of the application.
(7) The name of each well and the associated geologic formation from which the brine is produced.
(8) A chemical analysis of the brine for the parameters required by subsection (e). A representative sample of the brine to be spread may be used, provided that the operator demonstrates that the representative sample is equivalent to the brine being used for pre-wetting, anti-icing and de-icing.

(d) All plans will expire on June 30th of each year.

(e) Brines used for pre-wetting, anti-icing, and de-icing activities shall meet the following:

Allowable Level Parameter Allowable Level
Pre-wetting Anti-icing/De-icing
>170,000 mg/l TDS >170,000 mg/l
>80,000 mg/l Chloride >80,000 mg/l
>40,000 mg/l Sodium >40,000 mg/l
>20,000 mg/l Calcium >20,000 mg/l
5 to 9.5 pH 5 to 9.5
<500 mg/l Iron <500 mg/l
<100 mg/l Barium <30 mg/l
<10 mg/l Lead <5 mg/l
<1,000 mg/l Sulfate <400 mg/l
<15 mg/l Oil & Grease <15 mg/l
<0.5 mg/l Benzene <0.5 mg/l
<0.7 mg/l Ethylbenzene <0.7 mg/l
<1 mg/l Toluene <1 mg/l
<1 mg/l Xylene <1 mg/l

(f) The application rates for use of the natural gas well brines shall be limited to 10 gallons per ton for pre-wetting use, less than 50 gallons per lane per mile for anti-icing use, and less than 100 gallons per lane per mile for de-icing.

(g) Brines shall not be mixed with other types of solid wastes except bottom ash from the combustion of coal.

(h) Brine shall only be applied to the antiskid material immediately prior to roadway application. Application of brine to uncontained antiskid storage piles is prohibited.

(i) Anti-icing, de-icing and the spreading of pre-wetted antiskid material shall not be conducted on wooden or grated deck bridges.
(j) Brine shall not enter bodies of water or water courses.

(k) Except for storage at the well site, all storage of brine shall be in tanks in a manner that complies with the requirements set forth in 25 Pa. Code Chapter 299.

(l) Every three years each source of brine used for pre-wetting, anti-icing, and de-icing shall be analyzed for the parameters in subsection (e) prior to submittal of the plan required by subsection (a). The analysis shall be for each individual well utilized or it may be a composite of one or more samples of brines from wells, which produce gas from the same formation. The well permit number and producing formations shall be submitted with the analysis. If the brines used are obtained from a permitted brine treatment facility, the analysis of a representative composite sample shall be submitted along with the facility's NPDES permit number.

(m) For each new source of brine, the applicant shall submit an analysis of a representative sample of the brine including all parameters in subsection (e) to the Department. The brine analysis shall be submitted no less than thirty days prior to use. The applicant may utilize the brine in accordance with this section 30 days after submittal of the brine analysis unless otherwise instructed by the Department.

(n) Records of the analytical evaluations conducted on brine pursuant to subsections (e) and (l) shall be maintained by the applicant for a minimum or five years at the applicant's place of business and shall be available to the Department for inspection. At a minimum, these records shall include information on the dates of testing, each parameter tested, the results, the laboratory sampling procedures, analytical methodologies and the chain of custody.

(o) Trucks utilized to spread brine or pre-wetted antiskid material shall have signs identifying the person's name and business address on both sides of the truck. The signs shall have lettering that is at least six inches in height. Controls for spreading brine and pre-wetted anti-skid material shall be located in the cab of the truck.

(p) A copy of the current Department approved plan shall be kept in the spreading truck any time brine or pre-wetted antiskid material spreading is being conducted and shall be made available to the Department upon request.
(q) The Department shall be notified at least 24 hours before brine or pre-wetted antiskid material spreading will begin. This notice shall be submitted electronically to the Department through its website and include the date the activity will occur and the location where the activity will occur. If the date changes, the operator shall re-notify the Department in accordance with this paragraph.

(r) The responsible person identified on the approved plan shall submit a monthly report to the Department on forms provided by the Department listing the locations, frequency and amounts of brine or pre-wetted antiskid material spread during the previous month. Monthly brine spreading reports must be received by the Department on or before the 15th day of the month

that follows the month production brine was spread. These reports must be submitted to the Department on a monthly basis even if no activity took place in the previous month.

(s) Any changes to the approved plan must be submitted to the Department for approval. Approval must be obtained from the Department in writing prior to deviating from the plan or implementing any revisions to the plan.

(t) Failure to comply with this section may result in the Department rescinding the plan approval.

(u) Persons using brine for pre-wetting, anti-icing and de-icing activities in accordance with this section shall be deemed to have a residual waste permit by rule.

$_____ Annual cost savings per well site vs. disposal of brine.

§ 78.73. General provision for well construction and operation.

(c) Orphaned or abandoned wells identified pursuant to section 78.52a that likely penetrate a formation intended to be stimulated shall be visually monitored during stimulation activities. The operator shall immediately notify the Department of any change to the orphaned or abandoned well being monitored and take action to prevent pollution of waters of the Commonwealth or discharges to the surface.

$ 3000.00 Cost per well hydraulic fracturing operation.

(d) An operator that alters an orphaned or abandoned well by hydraulic fracturing shall plug the orphaned or abandoned well.

$ $25,000.00 Cost per well hydraulic fracturing operation.

Wallace, Todd

From: Malone, Shamus
Sent: Friday, May 17, 2013 8:56 AM
To: Perry, Scott (DEP)
Cc: Nolan, Elizabeth A.; Shirley, Jessica; Brokenshire, Stephen
Subject: FW: Cost Analysis - Chapter 78
Attachments: [redacted]Chapter 78 Cost Table - DRAFT.docx

Scott, this is the beginning of the flow of data from [redacted] and it looks like we are fairly close in numbers. Steve and I will be going over these numbers now and will give you our analysis.

Shamus M. Malone | Director
Bureau of Regulatory and Resources Enhancement
Office of Oil and Gas Management
Department of Environmental Protection
400 Market Street | Hbg, PA 17101
Phone: 717.772.2199 | Fax: 717.772.2291
www.dep.state.pa.us

From: [redacted]
Sent: Thursday, May 16, 2013 4:53 PM
To: Malone, Shamus
Cc: [redacted]
Subject: RE: Cost Analysis - Chapter 78

Shamus – I hope you're doing well. My apologies for not getting back to you sooner. I've been up to my ears in work and I've taken on a new position here, which adds on to the workload.

We have compiled the following initial draft of cost analysis figures for your review. We still have requests out to the [redacted] members for additional information to be added to this cost analysis. This draft has not gone through extensive QA/QC or auditing by an accountant. However, I mainly wanted to get you some information to start your review.

I'm going to be on vacation starting tomorrow through Memorial Day. However, if you need anything, let us know and we'll do our best to accommodate.

Look forward to talking to you again soon.

[redacted]

[redacted] - Chapter 78 Revisions Cost Analysis
Rough Draft (5/16/13)

Requirement	Times Required	Min Cost-Capex	Max Cost-Capex	Min Cost - Opex	Max Cost - Opex	Amortizatied? Period	Opportunity Cost	Total	Benefit
Ownership & Control (78.15b)	Every Application + win 30 days of any change								
Public Resource Agency Consultation (78.15d)	Every Application								
Permit Fees	Every Application	$2,000	$2,200						
Water Supply Complaint Notice (78.51d)	Upon receipt of a complaint	$500	$75,000						
Providing copies of Pre-drilling Survey	Optional		$600						
Providing Notice of water supply replacement rights	Unconventional Applications								
Abandoned and Orphan Well Identification (78.52a)	Every Application	$1,000	$15,000						
Prepare site specific PPC plan for oil and gas fluids (78.55b)	Every Application + when revised	$200	$3,500						
Unconventional well PPC plan for frac fluid containment systems (78.55c)	Every Application + when revised	$200	$300						
Prepare pressure barrier policy (78.55d)	Every Application + when revised	$200	$300						
Providing copies of PPC plan (78.55d)	When requested		$100						
Securing Department Approval of above ground modular containment systems (78.56a2)	When used								
Fencing or 24/7 staffing of unconventional well site pits (78.56a5)	Every unconventional well pad site with pits	$7,000	$50,000						
Providing 24/7 staffing or equipping tanks to prevent access by third parties (78.56a6)	Every unconventional well pad site with tanks	$3,000	$5,000						
Providing signage at unconventional well sites pits or tanks (78.56a7)	Every unconventional well pad site	$500	$2,000						
Providing pits with approved liners (78.56a9)	Every pit	$1,200							
Testing seams in liners (78.56a9iv)	Every seam								
Certifying that the bottom of pits on unconventional well pad sites is above seasonal gw table (78.56a11)	Every pit	$100	$20,000						
Notification of installation of pit liners (78.56a16)	Every pit								
Storing condensate in tanks w/ vapor controls and monitoring (78.56a17)	Every well pad site where condensate is produced								
Using closed top structures to store brine and other fluids produced during well completion (78.57a)	All well pad sites								
Providing secondary containment for all aboveground structures holding brine or other fluids (78.57c)	All well pad sites where brine or other fluids are produced	$2,000	$15,000						
Development of plan and gaining approval of the plan for processing of fluids for beneficial use (78.58a&c)	Any pad site where processing for beneficial use will occur except as exempted by 78.58b	$200	$300						
Development of plan for approval to process drill cuttings on site (78.58c)	Any pad site where drill cutting processing is proposed	$200	$300						
Characterization of solid wastes prior to leaving the well site (78.58d)	Any pad site where solid wastes are generated from the processing of fluids	$1,200	$5,000						
Impoundment embankment construction (78.59a)	All impoundments								
Construction, registration, operation (including 24/7 staffing or fencing) and restoration of freshwater impoundments (78.59b1f)	All freshwater impoundments								
Preparation and submittal of mine influenced water storage plan, testing of mine influenced waters and records retention (78.59b1g)	All impoundments used for storage of mine influenced water								
Siting, design construction, registration, operation (including 24/7 staffing or fencing plus monitoring) and restoration of centralized impoundments (78.59c)	All centralized impoundments not categorized as hazardous category 4 or size class C.								
Documentation and submittal of records for tophole water land application (78.60c)	Sites using land application for disposal of tophole water								
Application for approval of alternative practices for drill cuttings disposal (78.61 1 d)	When alternative practices are proposed	$100	$1,500						
Providing prior notice to disposing of drill cuttings (78.61 1 f)	When disposing of drill cuttings on site								
Disposal of solid wastes on site (78.62a5-14)	When disposing of solid wastes on site		$15,000						

PIOGA – Chapter 78 Revisions Cost Analysis
Rough Draft (5/16/13)

Containment Systems for unconventional well sites (78.64a)	All unconventional well sites	$3,000	$60,000	$85,000	$139,000				
Removal of all underground storage tanks	All well sites/tank batteries	$20,000 (per site)	$250,000 (per site)						
Site Restoration (78.65)	All well sites both after drilling and after plugging		$50,000						
Reporting and remediating releases (78.66)	After a spill or release of more than 5 gallons of a regulated substance								
Planning, development, operation and restoration of borrow pits (78.67)	All borrow pits								
Construction of gathering lines (78.68a)	All gathering lines								
Construction of temporary pipelines (78.68b)	All temporary pipelines								
Water Management and Water Reuse Plans (78.69)	All unconventional well operators	$2,500							
Road-Spreading of Brine (78.70)	All road spreading operations								
Use of Brine for Pre-wetting and anti-icing and de-icing(78.70a)	All pre-wetting, anti-icing and de-icing applications								
Visually monitoring orphaned or abandoned wells during well completion (78.73c)	All orphaned or abandoned wells identified as per 78.52a	$7,500							
Production Reporting (78.121)	All operators of unconventional wells	$12,000 (annual)							
Well Records and Completion Reports (78.122)	All wells	$1,500							