5500-FM-OG0001A Rev. 11/2007

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL AND GAS MANAGEMENT PROGRAM

WELL PERMIT

DEP USE ONLY	
Permittee's eFACTS ID: 277879	Auth ID: 825419
Watershed Name: N. Branch Culkins Creek	Quality: HQ

Permittee: NEWFIELD APPALACHIA PA LLC	OGO #: OGO-67425	Permit Number: 37-127-20012-	Date Issued: 04/29/2010
Address: 363 N SAM HOUSTON PKWY E STE 2020		Farm Name & Well Number: HL RUTLEDGE 1 1	Well Serial #
		Municipality: Damascus	County: Wayne
HOUSTON, TX 77060-2424		7½' Quadrangle Name: Galilee	Map Section #: 2
Phone: (281) 847-6031	Project #	Latitude: 41-43-43.2000	Longitude: -75-11-32.1000
Surf Elev at Site: 1440 feet	Anticipated Total Depth: 8350 feet / Well Type: GS	Offset distances referenced to NE corner of map section: South 7820 feet	West 6983 feet

This permit covering the well operator and well location shown above is evidence of permission granted to conduct activities in accordance with the Oil and Gas Act and the Oil and Gas Conservation Law, if the well is subject to that act and any rules and regulations promulgated thereunder, subject to the conditions contained herein and in accordance with the application submitted for this permit. This permit does not convey any property rights.

This permit and the permittee's authority to conduct the activities authorized by this permit are conditioned upon operator's compliance with applicable law and regulations.

Notification must be given to the district oil and gas inspector, the surface landowner and political subdivision of the date well drilling will begin at least 24 hours prior to commencement of drilling activities.

The permittee hereby authorizes and consents to allow, without delay, employees or agents of the Department to have access to and to inspect all areas upon presentation of appropriate credentials, without advance notice or a search warrant. This includes any property, facility, operation or activity governed by the Oil and Gas Act, the Oil and Gas Conservation Law, the Coal and Gas Resource Coordination Act and other statutes applicable to oil and gas activities administered by the Department. The authorization and consent shall include consent to the Department to collect samples of wastewaters or gases, to take photographs, to perform measurements, surveys, and other tests, to inspect any monitoring equipment, to inspect the methods of operation and disposal, and to inspect and copy documents required by the Department to be maintained. The authorization and consent includes consent to the Department to examine books, papers, and records pertinent to any matter under investigation pursuant to the Oil and Gas Act or pertinent to a determination of whether the operator is in compliance with the above referenced statutes. This condition in no way limits any other powers granted to the Department under the Oil and Gas Act and other statutes, rules and regulations applicable to these activities as administered by the Department.

This permit does not relieve the operator from the obligation to comply with the Clean Streams Law and all statutes, rules and regulations administered by the Department.

Special Permit Conditions:

This permit expires **04/29/2011** unless drilling is commenced on or before that date and prosecuted with due diligence.

Staci Gustafson for S. Craig Lobins
Regional Oil and Gas Program Manager

Stephen Watson	2 Public Square	570-826-2320
Oil & Gas Inspector	Wilkes-Barre, PA 18711-0790	Telephone

5500-FM-OG0004 Rev. 1/2010

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COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL AND GAS MANAGEMENT PROGRAM

DEP USE ONLY	
Site ID	Primary Fac ID 728266
Client Id 277879	Subfacility Id

Well Record and Completion Report

Operator: NEWFIELD APPALACHIA PA LLC	DEP ID#: 277879	Well API # (Permit / Reg): 37-127-20012-	Project Number:	Acres:
Address: 363 N SAM HOUSTON PKWY E STE 2020,		Well Farm Name & Well #: HL RUTLEDGE 1 1		Serial #:
City: HOUSTON	State: TX / Zip Code: 77060-2424	County: Wayne	Municipality: Damascus	
Phone: (281) 847-6031	Fax:	USGS 7.5 min. quadrangle map: Galilee		

Check all that apply: ☐ Original Well Record ☐ Original Completion Report ☐ Amended Well Record ☐ Amended Completion Report

WELL RECORD

Also complete the Log of Formations on back (page 2)

Well Type ☐ Gas ☐ Oil ☐ Combination Oil & Gas ☐ Injection ☐ Storage ☐ Disposal

Drilling Method ☐ Rotary – Air ☐ Rotary – Mud ☐ Cable Tool

Date Drilling Started	Date Drilling Completed	Surface Elevation	Total Depth – Driller	Total Depth – Logger
		ft.	ft.	ft.

Casing and Tubing

Cement returned on surface casing? ☐ Yes ☐ No
Cement returned on coal protective casing? ☐ Yes ☐ No ☐ N/A

Hole Size	Pipe Size	Wt.	Thread / Weld	Amount in Well (ft)	*Material Behind Pipe* Type and Amount	*Packer / Hardware / Centralizers* Type	Size	Depth	Date Run

COMPLETION REPORT

Perforation Record			Stimulation Record						
Date	Interval Perforated From	To	Date	Interval Treated	*Fluid* Type	Amount	*Propping Agent* Type	Amount	Average Injection

Natural Open Flow	Natural Rock Pressure	Hours	Days
After Treatment Open Flow	After Treatment Rock Pressure	Hours	Days

Well Service Companies -- Provide the name, address, and phone number of all well service companies involved.

Name	Name	Name
Address	Address	Address
City - State – Zip	City - State – Zip	City - State – Zip
Phone	Phone	Phone

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LOG OF FORMATIONS

Well API#: 37-127-20012--

(If you will need more space than this page, please photocopy the blank form before filling it in.)

Formation Name or Type	Top (feet)	Bottom (feet)	Gas at (feet)	Oil at (feet)	Water at (fresh / brine: ft.)	Source of Data

I do hereby certify to the best of my knowledge, information and belief that the well identified on this Well Record and Completion Report has been properly cased and cemented in accordance with the requirements of 25 Pa. Code Chapter 78 and any conditions contained in the permit for this well. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.

Well Operator's Signature

Title: Date:

DEP USE ONLY

Reviewed by: Date:

Comments:

5500-FM-OG0075 Rev. 8/2001

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL AND GAS MANAGEMENT PROGRAM

DEP USE ONLY	
Site ID	Primary Fac ID 728266
Client Id 277879	Subfacility id

Well Site Restoration Report

A. Operator and Well Information

Please read instructions on back before completing this form.

Well Operator: NEWFIELD APPALACHIA PA LLC	DEP ID#: 277879
Well API # (Permit / Reg): 37-127-20012-	
Address: 363 N SAM HOUSTON PKWY E STE 2020,	Well Farm Name & Well #: HL RUTLEDGE 1 1 — Serial #:
City: HOUSTON — State: TX — Zip Code: 77060-2424	County: Wayne — Municipality: Damascus
Phone: (281) 847-6031 — Fax:	

B. Land Application of Tophole Water

Date applied | pH

Volume (bbls) | Spec. cond. (μmhos/cm)

C. Off-site Waste Disposal

Type: ☐ Drilling Fluid (803) **Amount:** bbls

☐ Fracing Fluid (804) bbls

☐ Other, specify: **Qty:** bbls or tons

Method of disposal or reuse ☐ Sewage Treatment Plant (10)

☐ Disposal Well (04) ☐ Brine Treatment Plant (12)

☐ Landfill (05) ☐ Other (08)

Facility Information

Name | Permit #

Hauler Information

Name

Address

City | State | Zip Code

D. On-site Disposal – Drill Cuttings or Waste

Location of center of disposal area in relation to the well:

Course degrees | Distance feet

Describe the **material disposed**, including additives.

Specify disposal method

☐ Unlined pit, complete Section E. ☐ Dusting

☐ Lined pit, complete Section E. ☐ Solidification

☐ Land application, complete Section F. ☐ Other

E. Pit Disposal

Describe pit closure procedures.

Subbase, material: Thickness: inches

Pit liner, material: Thickness: mils

Pit dimensions (feet) Length: Width: Depth:

F. Land Application

Area: Length: feet Width: feet

Waste-to-soil ratio (by volume):

Chemical analysis of waste

Cadmium (Cd)	ppm	Nickel (Ni)	ppm
Copper (Cu)	ppm	Zinc (Zn)	ppm
Chromium (Cr)	ppm	Oil and Grease	%
Lead (Pb)	ppm	Spec. Cond.	μmhos/cm
Mercury (Hg)	ppm		

Well Operator's Signature

Title: Date:

DEP USE ONLY

Reviewed by: Date:

Comments:

Instructions for Well Site Restoration Report

Form 5500-FM-OG0075

Use this form to file the Well Site Restoration Report as required under 25 Pa. Code § 78.65(3). This report is to be filed with the department within 60 days after the restoration of the well site.

Section A. Operator and Well Information

Enter the name, address and telephone number of the well operator/permittee.

Provide the requested well information.

Section B. Land Application Of Tophole Water

Land application of tophole water must be performed in accordance with 25 Pa. Code § 78.60.

Provide the date(s) when tophole water was applied to the land, the estimated volume discharged, and the pH and specific conductance readings of the tophole water.

Section C. Off-site Waste Disposal

If disposing of residual waste off-site, complete this section.

Check the box next to each type of waste taken off-site for disposal. More than one box may be checked. Identify the number of barrels of drilling or fracing fluid removed. If checking "other", identify the waste and show the amount in either barrels or tons. Circle the appropriate unit of measurement.

Check the box next to the type of facility or site receiving the waste. Provide the name and permit number of the facility.

Provide the name and address of the person or company hauling the waste.

Section D. On-site Disposal – Drill Cuttings or Waste

If disposing of drill cuttings and/or residual waste on-site in accordance with 25 Pa. Code § 78.61 (Disposal of drill cuttings), § 78.62 (Disposal of residual waste—pits), or § 78.63 (Disposal of residual waste—land application), complete this section.

Locate the approximate center of the disposal area by giving the course in degrees and the distance in feet from the wellhead.

Describe the types of materials that were disposed on-site. Include drill cuttings above the surface casing seat, drill cuttings below the surface casing seat, cement returns, drilling muds, frac sands, and any other material that is being disposed on-site. Indicate any additives that were in the materials being disposed.

Additives are usually present to modify the performance of cement, drilling muds or frac sands. An example might be salt or oil in drilling muds.

Check the box next to the on-site disposal methods used. If "other" is checked, briefly describe the method of disposal.

Section E. Pit Disposal

If disposing of drill cuttings under 25 Pa. Code § 78.61 (Disposal of drill cuttings) complete the pit dimensions part of this section. If disposing of drill cuttings and/or residual waste under 25 Pa. Code § 78.62 (Disposal of residual waste—pits), complete all of this section.

Describe the procedures used to close the pit. The procedures should conform to requirements in 25 Pa. Code § 78.62.

Describe the type of material and thickness used for the subbase and pit liner. The manufacturer should be identified when describing the type of material used for the pit liner.

Provide the dimensions of the pit, giving the appropriate length, width, and depth in feet.

Section F. Land Application

If disposing of drill cuttings and/or residual waste including contaminated drill cuttings under 25 Pa. Code § 78.63, complete this section.

Provide the approximate length and width of the land application area in feet. Indicate the ratio of waste to soil by volume. As an example, if a 3-inch layer of waste was mixed into a 6-inch layer of soil the ratio would be 1/2. In no case may the ratio exceed 1/1.

Complete the chemical analysis information if it is requested by the department. The analysis is to be performed on the waste soil mixture after land application has occurred. See the guidelines for land application in the "Oil and Gas Operators Manual" for taking samples and for analysis methods.

If more room is needed to complete any section, provide the information on 8 ½" by 11" sheets of paper and attach to this form. Indicate the sections the information applies to.

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DEPARTMENT OF ENVIRONMENTAL PROTECTION
NORTHWEST REGIONAL OFFICE

Dear Operator:

Enclosed please find well permit(s) issued for drilling or altering a well. Developing this resource in a safe and environmentally protective manner is of utmost importance. As you may be aware, there have been several recent incidences where water supplies have been affected by natural gas migration. In order to prevent future impacts to the Commonwealth's water resources and provide a mechanism for ensuring public safety, the Department is providing the following information as a reminder of the cementing requirements for oil and gas wells.

Cementing

Properly cementing the casing of a well is critical to protecting water resources, preventing gas migration, and ensuring well integrity. If the casing is improperly cemented or if insufficient cement is used, such as when cement is not returned to the surface, the operator should notify the Department pursuant to 25 Pa. Code § 78.86.

In addition, when cementing surface casing, 25 Pa. Code § 78.85 states that the cement must be allowed to set for at least 8 hours *and* until the cement attains a compressive strength of at least 350 psi. While the cement is setting, the casing must not be disturbed. This includes any activity that may cause movement or pressure changes to the casing or the cement sheath surrounding the casing. After the cement is set, care must be taken when drilling through the plug to prevent damaging the seal at the casing seat. Disturbing the casing while cement is setting or damaging the seal at the casing seat may provide a mechanism for gas and other fluids to escape from the well and contaminate groundwater and water supplies. If this occurs, the operator must notify the Department.

In addition, the Department also reminds you of the following reporting requirements for oil and gas wells.

Reporting

1. Pursuant to Section 212(b) of the Oil and Gas Act and Section 78.122(a) of Chapter 78 of the Oil and Gas Regulations, a **Well Record** must be submitted to the Department within thirty (30) days of cessation of drilling or altering a well.

2. Pursuant to Section 212(b) of the Oil and Gas Act and Section 78.122(b) of Chapter 78 of the Oil and Gas Regulations, a **Completion Report** must be submitted to the Department within thirty (30) days of completion of the well. A copy of the Well Record and Completion Report is enclosed with this letter. This is a newly revised form which requires the operator to certify that the well has been cased and cemented according to the requirements of 25 Pa. Code Chapter 78. Well Record and Completion Report forms that do not contain this certification will not be accepted by the Department. Additional copies of this form can be obtained from the Department's eLibrary at http://www.elibrary.dep.state.pa.us/dsweb/View/Collection-9841

3. Pursuant to Section 212(a) of the Oil and Gas Act, a report specifying the well status and production on the most well-specific basis available is to be provided to the Department. Section 78.121 of Chapter 78 details the reporting time frames required for various well types, waste reporting, and the acceptable format for the **Well and Waste Production Report** submissions.

4. Also note that pursuant to Section 212(b) of the Oil and Gas Act, the Department has the authority to request and does hereby request you submit a digital copy on CD of **ALL Well Logs** (temperature, electrical, radioactive, gamma ray, neutron, induction, resistivity, multi-arm caliper, acoustic, optical, etc.) that have been run on this well.

The above records and logs are to be submitted to the Department of Environmental Protections, Oil and Gas Management, 230 Chestnut St., Meadville, Pa 16335-3481 to the attention of the Regional Oil and Gas Manager.

Thank you for your cooperation in this matter.

Sincerely,

S. Craig Lobins

S. Craig Lobins
Regional Manager
Oil and Gas Management

Please note that the most recent revision of the Application for Drilling or Altering a Well must be submitted with all drilling applications. Please check the website below for the most recent revisions for all forms.
http://www.dep.state.pa.us/dep/deputate/minres/oilgas/o_gforms.htm

The Erosion, Sediment& Storm water Control Module is no longer being accepted for ESCGP-1 applications. Please submit the complete ESCGP-1 application for any projects. The most recent revisions must be submitted along with the application fee of $500.00

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COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL AND GAS MANAGEMENT PROGRAM

DEP USE ONLY	
Permittee's eFACTS ID 277879	Auth ID 827248
Watershed Name Little Equinunt Creek	HQ

WELL PERMIT

Permittee NEWFIELD APPALACHIA PA LLC	OGO.# OGO-67425	Permit Number 37-127-20015-	Date Issued 05/07/2010
Address 363 N SAM HOUSTON PKWY E STE 2020		Farm Name & Well Number EM SCHWEIGHOFER 1 1	Well Serial #
		Municipality Damascus	County Wayne
HOUSTON, TX 77060-2424		7½ ' Quadrangle Name Long Eddy	Map Section # 8
Phone (281) 847-6031	Project #	Latitude 41-45-15.0000	Longitude -75-10-58.3000
Surf Elev at Site 1311 feet	Anticipated Total Depth 8350 feet	Well Type TE	Offset distances referenced to NE corner of map section. South 13664 feet West 4419 feet

This permit covering the well operator and well location shown above is evidence of permission granted to conduct activities in accordance with the Oil and Gas Act and the Oil and Gas Conservation Law, if the well is subject to that act and any rules and regulations promulgated thereunder, subject to the conditions contained herein and in accordance with the application submitted for this permit. This permit does not convey any property rights.

This permit and the permittee's authority to conduct the activities authorized by this permit are conditioned upon operator's compliance with applicable law and regulations.

Notification must be given to the district oil and gas inspector, the surface landowner and political subdivision of the date well drilling will begin at least 24 hours prior to commencement of drilling activities.

The permittee hereby authorizes and consents to allow, without delay, employees or agents of the Department to have access to and to inspect all areas upon presentation of appropriate credentials, without advance notice or a search warrant. This includes any property, facility, operation or activity governed by the Oil and Gas Act, the Oil and Gas Conservation Law, the Coal and Gas Resource Coordination Act and other statutes applicable to oil and gas activities administered by the Department. The authorization and consent shall include consent to the Department to collect samples of wastewaters or gases, to take photographs, to perform measurements, surveys, and other tests, to inspect any monitoring equipment, to inspect the methods of operation and disposal, and to inspect and copy documents required by the Department to be maintained. The authorization and consent includes consent to the Department to examine books, papers, and records pertinent to any matter under investigation pursuant to the Oil and Gas Act or pertinent to a determination of whether the operator is in compliance with the above referenced statutes. This condition in no way limits any other powers granted to the Department under the Oil and Gas Act and other statutes, rules and regulations applicable to these activities as administered by the Department.

This permit does not relieve the operator from the obligation to comply with the Clean Streams Law and all statutes, rules and regulations administered by the Department.

Special Permit Conditions:

This permit expires 05/07/2011 unless drilling is commenced on or before that date and prosecuted with due diligence.

S. Craig Lob

Regional Oil and Gas Program Manager

Stephen Watson
Oil & Gas Inspector

2 Public Square
Wilkes-Barre, PA 18711-0790

570-826-2320
Telephone

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DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL & GAS MANAGEMENT PROGRAM

DEP USE ONLY	
AUTH #	NC
Check # 1064289	Amount $ 1500.10

$1250 + 250 = $1500

PERMIT APPLICATION FOR DRILLING OR ALTERING A WELL

DEP USE ONLY

Notes		Objection Date - Do not issue before:	Well Permit # 127-20015
Vertical test Well	OGO # 67425	4/5/10	Special Cond. A B C D E F
	Bond # 123822	Date Approved	Watershed Name: Little Equinunk Creek
	C: 3/16/10 del G: 4/5/10	4/20/10 JJS	Designation: HQ EV
	INV: 5-7-10		

Please read instructions before you begin filling in this form.

Applicant (Operator) Name	DEP Client ID#	Phone	FAX	Check if new address. ☐
Newfield Appalachia PA LLC	277879	281-847-6031	281-847-6160	
Mailing Address (Street or PO Box): 363 N. Sam Houston Pkwy E. Suite 2020	City: Houston	State: TX	Zip +4: 77060-2424	Country (if not USA)

(Well) Farm Name	Well #	Serial #
E.M. Schweighofer	1-1	
County: WAYNE	Municipality: DAMASCUS	Project # (from DEP)

If you are applying for a permit to redrill, drill deeper, or alter a well that was previously permitted or registered, ***or for a well site that was previously permitted but not drilled,*** check this box ☐ and enter the permit or registration number here:

If applying for a permit to rework an existing well not registered or permitted, check this box ☐ and **enter date drilled**, if known:__________ (see instructions)

PNDI Attached: ☒ Any "hit" must include accepted mitigation plan from applicable agency.

PERMIT TYPE
Check applicable.
Application is to:
- ☒ Drill a new well
- ☐ Deepen a well
- ☐ Redrill a well
- ☐ Alter a well
- ☐ E&S Control Module
- ☐ Other (specify)

TYPE OF WELL
Check one.
- ☐ Gas
- ☐ Oil
- ☐ Comb. (gas & oil)
- ☐ Injection, recovery
- ☐ Injection, disposal
- ☐ Coalbed Methane
- ☐ Gas Storage
- ☒ Other (specify) vertical test well

APPLICATION FEE
Check applicable.
- ☐ Marcellus Well: Non-Vertical
- ☐ Marcellus Well: Vertical
- ☐ Non-Marcellus Well: Non-Vertical
- ☒ Non-Marcellus Well: Vertical
- ☐ $200 (Home Use Well)
- ☐ $500 E&S Fee
- ☐ $ 0 (Rehab orphan)
- ☒ Vertical: Length 8350 ft.
- ☐ Marcellus: Length ____ ft.
- ☐ Non-Vertical: Length ____ ft.

Total Application Fee $ 1500

COORDINATION WITH REGULATIONS AND OTHER PERMITS	Yes	No
1. Will the well be subject to the **Oil and Gas Conservation Law**? If "No," go to 2).	☒	☐
a. If "Yes" to #1, is the well at least 330 feet from outside lease or unit boundary?	☒	☐
b. Does the location fall within an area covered by a spacing order?	☐	☒
2. Will the well penetrate a **workable coal seam**? If "No," include justification and supporting documentation.	☐	☒
3. If the well will penetrate a **workable coal seam**, and the well is a "non-conservation" gas well, does the location comply with the distance requirements of Section 7 of the Coal and Gas Resource Coordination Act? (At least 1,000 feet from all existing wells).	☐	☐
a. If "No," is the required exception request attached? (Check here if re-working an existing well: ☐ N/A)	☐	☐
4. Will the well be drilled at a location where the **coal** has been removed?	☐	☒
5. Will the well be drilled through an **active (operating or projected) coalmine**, or within 1,000 feet of the boundary?	☐	☒
a. If "Yes," print the names of: Mine: Operator:		
6. Will the well penetrate or be within 2,000 feet of an active **gas storage reservoir** boundary?	☐	☒
a. If Yes, print the names of: Storage Field: Operator:		
7. Is the proposed well location within the permitted area of a **landfill**?	☐	☒
8. Will the well site be within 100 feet (measured horizontally) of a **stream, spring or body of water** identified on the most current 7½' topographic map?	☐	☒
a. If "Yes," is a request for a waiver (form 5500-FM-OG0057), and E&S control plan attached?	☐	☐
9. Will the well site be within 100 feet of a **wetland** or in a **wetland**?	☐	☒
a. Is the well site within 100 feet of a wetland greater than one acre in size?	☐	☐
If yes, is a waiver request (form 5500-FM-OG0057) and E&S control plan attached?	☐	☐
10. Will the well be drilled within 200 feet (horizontally) from any existing **building** or an existing **water supply**?	☐	☒
a. If "Yes," is written consent from the owner attached?	☐	☐
b. If written consent is not attached, is a variance request (form 5500-FM-OG0058) attached?	☐	☐
11. Will the well be located where it may impact a public resource as outlined in the "**Coordination of a Well Location with Public Resources**" form 5500-PM-OG0076? If yes, attach a competed copy of the form.	☐	☒
12. Is the well site in a **Special Protection** High Quality (HQ) or Exceptional Value (EV) watershed?	☒	☐
13. Is this well part of a development where you need an **Earth Disturbance Permit** for Oil and Gas Activities disturbing more than 5 acres? If yes, attach a completed Erosion Sediment and Stomwater Control Module or list the number and date of the ESCGP-1 Approval. ______	☐	☒

DEP USE ONLY
Date Stamps/Notes
Auth 827248
Site 732146
Clnt 277879
APS 715652
Acct 675003
PF 728807
SF 1010511

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MAR 12 2010
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NORTHWEST REGIONAL OFFICE

Signature of Applicant — The person signing this form attests that they have the authority to submit this application on behalf of the applicant, and that the information, including all related submissions, is true and accurate to the best of their knowledge.

Signature of Person Authorized to Submit Application	(Print or Type)	Name of Signer: DONALD F. SLEETH / Title: Drilling Manager	Date
Donald F. Sleeth II			3-10-10

Application Preparer/Contact: BETSY COLLINS Phone: 412-921-8250

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DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL & GAS MANAGEMENT PROGRAM

Farm Name - Well #	E.M. Schweighofer-Well #1-1
Applicant Name	Newfield Appalachia PA LLC
DEP ID#	277879
DEP USE ONLY	APS #

127 - 20015

PERMIT APPLICATION FOR DRILLING OR ALTERING A WELL
Page 2 — Record of Notification / Written Consent

List the following: surface landowner; all landowners or water purveyors whose water supplies are within 1,000 feet of this proposed well location; gas storage operator if within 2000 feet; all coal owners and lessees of all underlying workable coal seams; operators of underground coal mines at the proposed location; and coal operators with a deep mine within 1,000 feet. Mark the boxes, "X," which show the parties' interests. Use additional forms if you need more space. You are required to notify each of these parties.

Name	Address	Surface Landowner	Coal Owner	Coal Lessee	Coal Mine Operator	Gas Storage Operator	Within 1,000 feet: Surf Owner with Water	Within 1,000 feet: Water Purveyor	Within 1,000 feet: Coal Mine Operator	Notification (Note the means and attach proof.) Certified Mail Dates: Sent	Certified Mail Dates: Return Receipt	Address Affidavit	Written Consent
Jeffrey Holloway	519 Chicopee Road Equinunk, PA 18417-3071						X						X
Sheila Bochicchio	204 Eller Cove Road Weaverville, NC 28787-9713						X						X
Greg Ratti	141 Highwood Avenue Leonia, NJ 07605-2007						X			2/13/10	2/17/10		
Edward M & Marian Schweighofer	10 Twin Brook Farm Ln Tyler Hill, PA 18469-4037	X					X						X
Prairie Hill Hunting Club	2631 Hancock Hwy Equinunk, PA 18417-3001						X			2/19/10	3/1/10		

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Optional: Signature below indicates the party's approval of the well location, and waives the 15-day objection period. Check applicable box.

☐ Water Purveyor or ☒ Landowner with water supply within 1,000 ft. Marian Schweighofer / Edward M. Schweighofer	Date 2/8/10	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
☐ Water Purveyor or ☑ Landowner with water supply within 1,000 ft. Jeff Holloway	Date 2-18-10	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
☐ Water Purveyor or ☐ Landowner with water supply within 1,000 ft.	Date	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
☐ Water Purveyor or ☐ Landowner with water supply within 1,000 ft.	Date	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
Surface Landowner at proposed location Marian Schweighofer	Date 2/8/10	Coal Operator within 1,000 feet of proposed location	Date
Surface Landowner at proposed location Edward M. Schweighofer	Date 2/8/10	Gas Storage Operator within 2,000 feet	Date

Signature below indicates written consent. Check applicable box.

Owner of: ☐ water supply, or ☐ building within 200 feet	Date
Address (of above)	
Owner of: ☐ water supply, or ☐ building within 200 feet	Date
Address (of above)	

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OIL & GAS MANAGEMENT PROGRAM

Farm Name - Well #	
E.M. Schweighofer-Well #1-1	
Applicant Name: Newfield Appalachia PA, LLC	DEP ID# 277879
DEP USE ONLY	APS #

PERMIT APPLICATION FOR DRILLING OR ALTERING A WELL
Page 2 --- Record of Notification / Written Consent

127-20015

List the following: surface landowner; all landowners or water purveyors whose water supplies are within 1,000 feet of this proposed well location; gas storage operator if within 2000 feet; all coal owners and lessees of all underlying workable coal seams; operators of underground coal mines at the proposed location; and coal operators with a deep mine within 1,000 feet. Mark the boxes, "X," which show the parties' interests. Use additional forms if you need more space. You are required to notify each of these parties.

Name	Address	Surface Landowner	Coal Owner	Coal Lessee	Coal Mine Operator	Gas Storage Operator	Within 1,000 feet: Surf Owner with Water	Within 1,000 feet: Water Purveyor	Within 1,000 feet: Coal Mine Operator	Notification (Note the means and attach proof.) Certified Mail Dates: Sent	Certified Mail Dates: Return Receipt	Address Affidavit	Written Consent
Jeffrey Holloway	519 Chicopee Road Equinunk, PA 18417-3071						X						X
Sheila Bochicchio	204 Eller Cove Road Weaverville, NC 28787-9713						X						X
Greg Ratti	141 Highwood Avenue Leonia, NJ 07605-2007						X			2/13/10	2/17/10		
Edward M & Marian Schweighofer	10 Twin Brook Farm Ln Tyler Hill, PA 18469-4037	X					X						X
Prairie Hill Hunting Club	2631 Hancock Hwy Equinunk, PA 18417-3001						X			2/19/10	3/1/10		

Optional: Signature below indicates the party's approval of the well location, and waives the 15-day objection period. Check applicable box.

☐ Water Purveyor or ☐ Landowner with water supply within 1,000 ft.	Date	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
☐ Water Purveyor or ☐ Landowner with water supply within 1,000 ft.	Date	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
☐ Water Purveyor or ☐ Landowner with water supply within 1,000 ft.	Date	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
☐ Water Purveyor or ☐ Landowner with water supply within 1,000 ft.	Date	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
Surface Landowner at proposed location	Date	Coal Operator within 1,000 feet of proposed location	Date
Surface Landowner at proposed location	Date	Gas Storage Operator within 2,000 feet	Date

Signature below indicates written consent. Check applicable box.

Owner of: ☑ water supply, or ☐ building within 200 feet Address (of above) [signature]	Date 3/19/2010
Owner of: ☐ water supply, or ☐ building within 200 feet Address (of above)	Date

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Rodney Young
Prairie Hill Hunting Club
3386 Hancock Highway
Equinunk, PA 18417

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X
☐ Agent
☐ Addressee

B. Received by (Printed Name) Randy Young

C. Date of Delivery 3/1/10

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☐ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number
(Transfer from servic 91 7108 2133 3937 7523 1766

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Greg Ratti
141 Highwood Ave.
Leonia, NJ 07605

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X
☐ Agent
☐ Addressee

B. Received by (Printed Name) Greg Ratti

C. Date of Delivery 2-17-10

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☐ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number
(Transfer from service label) 91 7108 2133 3937 7523 1568

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

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RECEIVED
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NORTHWEST REGIONAL OFFICE

Angie Prather

Confirmation Services

Package ID: 9171082133393775231643 — E-CERTIFIED
Destination ZIP Code: 78002 — PRIORITY CBP ENV/PKG
Customer Reference:
Recipient: Mr. Sammy DeSpain — PBP Account #: 13945647
Address: P.O. Box 606 — Serial #: 4253999
Georgewest, Tx 78022 — FEB 19 2010 12:27P

Amie Faul

Confirmation Services

Package ID: 9171082133393775231650 — E-CERTIFIED
Destination ZIP Code: 18443 — 1STCL REGULAR FLAT
Customer Reference:
Recipient: William S. Diane Briggs — PBP Account #: 13945647
Address: 117 High Bridge Rd. — Serial #: 4253999
Milanville, PA 18443 — FEB 22 2010 5:55P

D. Wooley

Confirmation Services

Package ID: 9171082133393775231667 — E-CERTIFIED
Destination ZIP Code: 77210 — 1STCL REGULAR FLAT
Customer Reference:
Recipient: City of Houston Municipal Courts — PBP Account #: 13945647
Address: P.O. Box 4996 — Serial #: 4253999
Hou. Tx 77210 — FEB 23 2010 10:37A

Confirmation Services

Package ID: 9171082133393775231766 — E-CERTIFIED
Destination ZIP Code: 18417 — 1STCL REGULAR FLAT
Customer Reference:
Recipient: Randy Young — PBP Account #: 13945647
Address: Prairie Hill Hunting — Serial #: 4253999
Equinunk, PA 18417 — FEB 24 2010 3:41P

Confirmation Services

Destination ZIP Code: 33418 — 1STCL REGULAR FLAT

Customer Reference:

Recipient: Diego Edelmenn — PBP Account #: 13945647

Address: 253 Isle Way — Serial #: 4253999

Palm Beach Gardens, FL 33418 — FE[illegible]10 1:56P

A. Faul

Confirmation Services

Package ID: 9171082133393775231551 — E-CERTIFIED

Destination ZIP Code: 28787 — 1STCL REGULAR FLAT

Customer Reference:

Recipient: Sheila Bochicchio — PBP Account #: 13945647

Address: 204 Eller Cove Road — Serial #: 4253999

Weaverville, NC 28787 — FEB 12 2010 1:56P

A. Faul

Confirmation Services

Package ID: 9171082133393775231568 — E-CERTIFIED

Destination ZIP Code: 07605 — 1STCL REGULAR FLAT

Customer Reference:

Recipient: Greg Ratti — PBP Account #: 13945647

Address: 141 Highwood Ave — Serial #: 4253999

Leonia, NJ 07605 — FEB 12 2010 1:56P

D. FINLEY

Confirmation Services

Package ID: 9171082133393775231575 — E-CERTIFIED

Destination ZIP Code: 78214 — 1STCL REGULAR FLAT

Customer Reference:

Recipient: DORIS ELLIS — PBP Account #: 13945647

Address: 814 PLEASANTON RD #324 — Serial #: 4253999

SAN ANTONIO, TX 78214 — FEB 16 2010 4:10P

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D. FINLEY

Confirmation Services

Package ID: 9171082133393775231582 — E-CERTIFIED

Destination ZIP Code: 77584 — 1STCL REGULAR FLAT

Customer Reference:

Recipient: BILLY W COCKRELL — PBP Account #: 13945647

Address: 17214 HARKEY RD COUNTY RD 103 — Serial #: 4253999

PEARLAND, TX 77584 — FEB 17 2010 12:46P

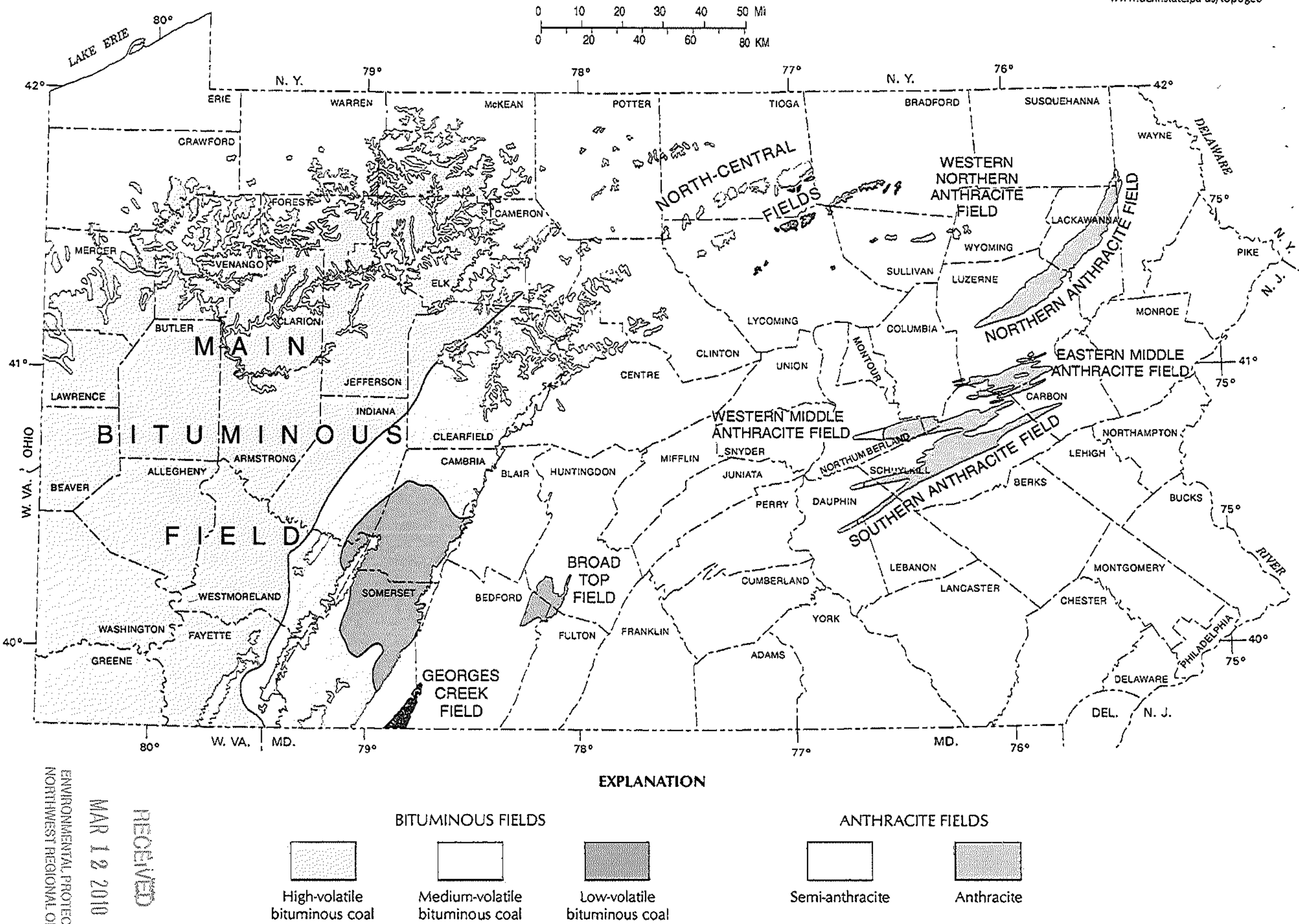
MAP 11

DCNR

DISTRIBUTION OF PENNSYLVANIA COALS

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF
CONSERVATION AND NATURAL RESOURCES
BUREAU OF TOPOGRAPHIC AND GEOLOGIC SURVEY
www.dcnr.state.pa us/topogeo

SCALE 1:2,000,000

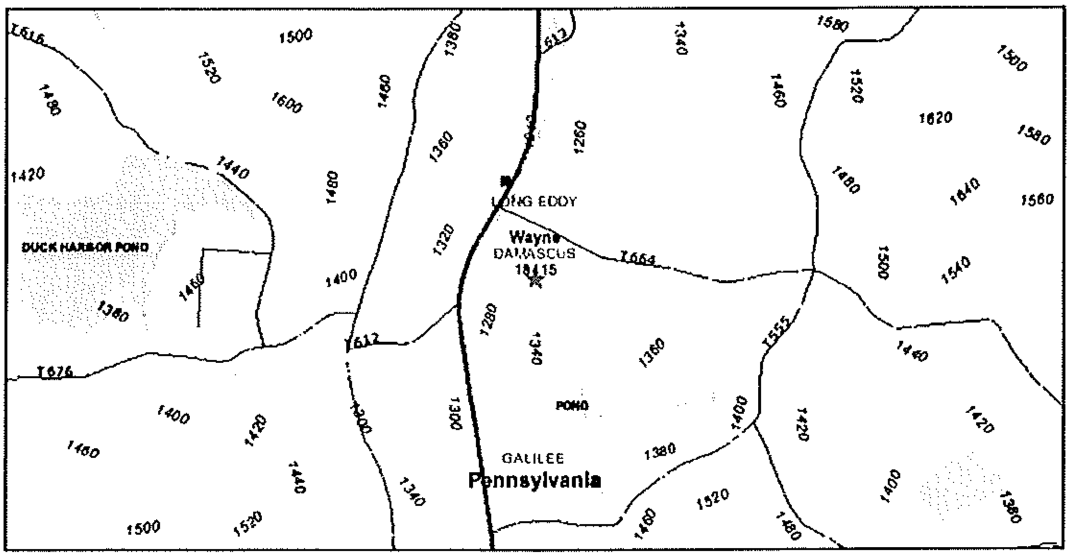


Prepared by Bureau of Topographic and Geologic Survey.
Third Edition, Revised, 2000; Third Printing, 2008.

2200–MP–DCNR0855
Printed on Recycled Paper

1. PROJECT INFORMATION

Project Name: **Newfield-7-Schweighofer**
Date of review: **1/21/2010 10:09:47 AM**
Project Category: **Mining,Oil or Gas (including roads and pipelines),New Well**
Project Area: **N/A**
County: **Wayne** Township/Municipality: **Damascus**
Quadrangle Name: **LONG EDDY**
ZIP Code: **18415**
Decimal Degrees: **41.7541603 N, -75.1828497 W**
Degrees Minutes Seconds: **41° 45' 14.98" N, -75° 10' 58.26" W**



2. SEARCH RESULTS

Agency	Results	Response
PA Game Commission	No Known Impact	No Further Review Required
PA Department of Conservation and Natural Resources	No Known Impact	No Further Review Required
PA Fish and Boat Commission	No Known Impact	No Further Review Required
U.S. Fish and Wildlife Service	No Known Impact	No Further Review Required

As summarized above, Pennsylvania Natural Diversity Inventory (PNDI) records indicate no known impacts to threatened and endangered species and/or special concern species and resources within the project area. Therefore, based on the information you provided, no further coordination is required with the jurisdictional agencies. This response does not reflect potential agency concerns regarding impacts to other ecological resources, such as wetlands.

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3. AGENCY COMMENTS

Regardless of whether a DEP permit is necessary for this proposed project, any potential impacts to threatened and endangered species and/or special concern species and resources must be resolved with the appropriate jurisdictional agency. In some cases, a permit or authorization from the jurisdictional agency may be needed if adverse impacts to these species and habitats cannot be avoided.

These agency determinations and responses are **valid for one year** (from the date of the review), and are based on the project information that was provided, including the exact project location; the project type, description, and features; and any responses to questions that were generated during this search. If any of the following change: 1) project location, 2) project size or configuration, 3) project type, or 4) responses to the questions that were asked during the online review, the results of this review are not valid, and the review must be searched again via the PNDI Environmental Review Tool and resubmitted to the jurisdictional agencies. The PNDI tool is a primary screening tool, and a desktop review may reveal more or fewer impacts than what is listed on this PNDI receipt. The PNDI tool is a primary screening tool, and a desktop review may reveal more or fewer impacts than what is listed on this PNDI receipt.

PA Game Commission

RESPONSE: No Impact is anticipated to threatened and endangered species and/or special concern species and resources.

PA Department of Conservation and Natural Resources

RESPONSE: No Impact is anticipated to threatened and endangered species and/or special concern species and resources.

PA Fish and Boat Commission

RESPONSE: No Impact is anticipated to threatened and endangered species and/or special concern species and resources.

U.S. Fish and Wildlife Service

RESPONSE: No impacts to **federally** listed or proposed species are anticipated. Therefore, no further consultation/coordination under the Endangered Species Act (87 Stat. 884, as amended; 16 U.S.C. 1531 *et seq.* is required. Because no take of federally listed species is anticipated, none is authorized. This response does not reflect potential Fish and Wildlife Service concerns under the Fish and Wildlife Coordination Act or other authorities.

4. DEP INFORMATION

The Pa Department of Environmental Protection (DEP) requires that a signed copy of this receipt, along with any required documentation from jurisdictional agencies concerning resolution of potential impacts, be submitted with applications for permits requiring PNDI review. For cases where a "Potential Impact" to threatened and endangered species has been identified before the application has been submitted to DEP, the application should not be submitted until the impact has been resolved. For cases where "Potential Impact" to special concern species and resources has been identified before the application has been submitted, the application should be submitted to DEP along with the PNDI receipt, a completed PNDI form and a USGS 7.5 minute quadrangle map with the project boundaries delineated on the map. The PNDI Receipt should also be submitted to the appropriate agency according to directions on the PNDI Receipt. DEP and the jurisdictional agency will work together to resolve the potential impact(s). See the DEP PNDI policy at http://www.naturalheritage.state.pa.us.

5. ADDITIONAL INFORMATION

The PNDI environmental review website is a **preliminary** screening tool. There are often delays in updating species status classifications. Because the proposed status represents the best available information regarding the conservation status of the species, state jurisdictional agency staff give the proposed statuses at least the same consideration as the current legal status. If surveys or further information reveal that a threatened and endangered and/or special concern species and resources exist in your project area, contact the appropriate jurisdictional agency/agencies immediately to identify and resolve any impacts.

For a list of species known to occur in the county where your project is located, please see the species lists by county found on the PA Natural Heritage Program (PNHP) home page (www.naturalheritage.state.pa.us). Also note that the PNDI Environmental Review Tool only contains information about species occurrences that have actually been reported to the PNHP.

6. AGENCY CONTACT INFORMATION

PA Department of Conservation and Natural Resources
Bureau of Forestry, Ecological Services Section
400 Market Street, PO Box 8552, Harrisburg, PA. 17105-8552
Fax:(717) 772-0271

U.S. Fish and Wildlife Service
Endangered Species Section
315 South Allen Street, Suite 322, State College, PA. 16801-4851
NO Faxes Please.

PA Fish and Boat Commission
Division of Environmental Services
450 Robinson Lane, Bellefonte, PA. 16823-7437
NO Faxes Please

PA Game Commission
Bureau of Wildlife Habitat Management
Division of Environmental Planning and Habitat Protection
2001 Elmerton Avenue, Harrisburg, PA. 17110-9797
Fax:(717) 787-6957

7. PROJECT CONTACT INFORMATION

Name: Betsy Collins
Company/Business Name: Tetra Tech, NUS
Address: 661 Andersen Drive, Foster Plaza 7
City, State, Zip: Pittsburgh, PA 15220
Phone: (412) 921-8250 Fax: (412) 921-4040
Email: Betsy.Collins@tetratech.com

8. CERTIFICATION

I certify that ALL of the project information contained in this receipt (including project location, project size/configuration, project type, answers to questions) is true, accurate and complete. In addition, if the project type, location, size or configuration changes, or if the answers to any questions that were asked during this online review change, I agree to re-do the online environmental review.

applicant/project proponent signature ______ date 1/21/10

NEWFIELD

RECEIVED

APR 02 2010

ENVIRONMENTAL PROTECTION
NORTHWEST REGIONAL OFFICE

April 1, 2010

PADEP Oil & Gas Management
230 Chestnut St.
Meadville, PA 16335

Subject: Newfield Appalachia PA LLC – DEP ID# 277879
E.M. Schweighofer Well #1-1

To Whom It May Concern:

Please include this letter of clarification as part of our permit application associated with the above captioned well.

This permit is to develop a well which is intended solely for exploratory purposes. A core is to be taken from several formations throughout the drilling process of this well and additional scientific study is to be performed on multiple formations including, but not limited to, geophysical logs, micro-seismic studies and fluid sampling. As permitted and configured, this well is not to be completed for production, not to be hydraulically fractured and is not to produce gas. In the future, this wellbore will either be plugged and abandoned per PADEP regulations, converted to inactive status and utilized as a monitoring well, or reconfigured and converted to a production well. Prior to either plugging and abandonment, conversion to inactive status or reconfiguration and conversion to production, we acknowledge that additional permitting will be necessary with approvals from the PADEP and other regulatory bodies with jurisdiction.

Sincerely,

Donald F. Sleeth
Drilling Manager

Tetra Tech NUS
Foster Plaza 7
661 Andersen Drive
Pittsburgh, PA 15220-2745
Tel: (412) 921-7090
Fax: (412) 921-4040

LETTER OF TRANSMITTAL

DATE: 9 April 2010	JOB NO.: 112C02679
ATTENTION: Aaron O'Hara	
RE: Newfield – Schweighofer 1-1 Well Plat	

TO

Pa DEP Northwest Regional Office
230 Chestnut Street
Meadville, Pa 16335
814-332-6870

WE ARE SENDING YOU [X] Attached [ ] Under separate cover via ________ the following items:

[ ] Shop drawings [ ] Prints [ ] Plans [ ] Samples [ ] Specifications

[ ] Copy of letter [ ] Change order [ ] ________________________________

COPIES	DATE	NO.	DESCRIPTION
1			Schwieghofer Well Plat 1-1 – sealed original

THESE ARE TRANSMITTED as checked below:

[ ] For approval [ ] Approved as submitted [ ] Resubmit ___ copies for approval

[x] For your use [ ] Approved as noted [ ] Submit ____copies for distribution

[ ] As requested [ ] Returned for corrections [ ] Return ____ corrected prints

[ ] For review and comment [ ] For Your Signature

[ ] FOR BIDS DUE _______________ 19 ___ [ ] PRINTS RETURNED AFTER LOAN TO US

REMARKS:

Attached is the revised original Schweighofer well plat with the revisions based upon our telephone conversation on 6 April 2010. Should you require any additional information, please contact me (412) -921-8873 at any time.

SIGNED Allan R. Berenbrok

Allan R. Berenbrok, P.E.

CC: file (w/a)
Andrew Strassner (w/a)
Don Sleeth (w/a)

RECEIVED
APR 12 2010
ENVIRONMENTAL PROTECTION
NORTHWEST REGIONAL OFFICE

5500-PM-OG0002 Rev. 9/2008

pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL AND GAS MANAGEMENT PROGRAM

WELL LOCATION PLAT

DEP USE ONLY	Auth ID #:	G:
	Permit #: 127-20015	
	Project #:	C:

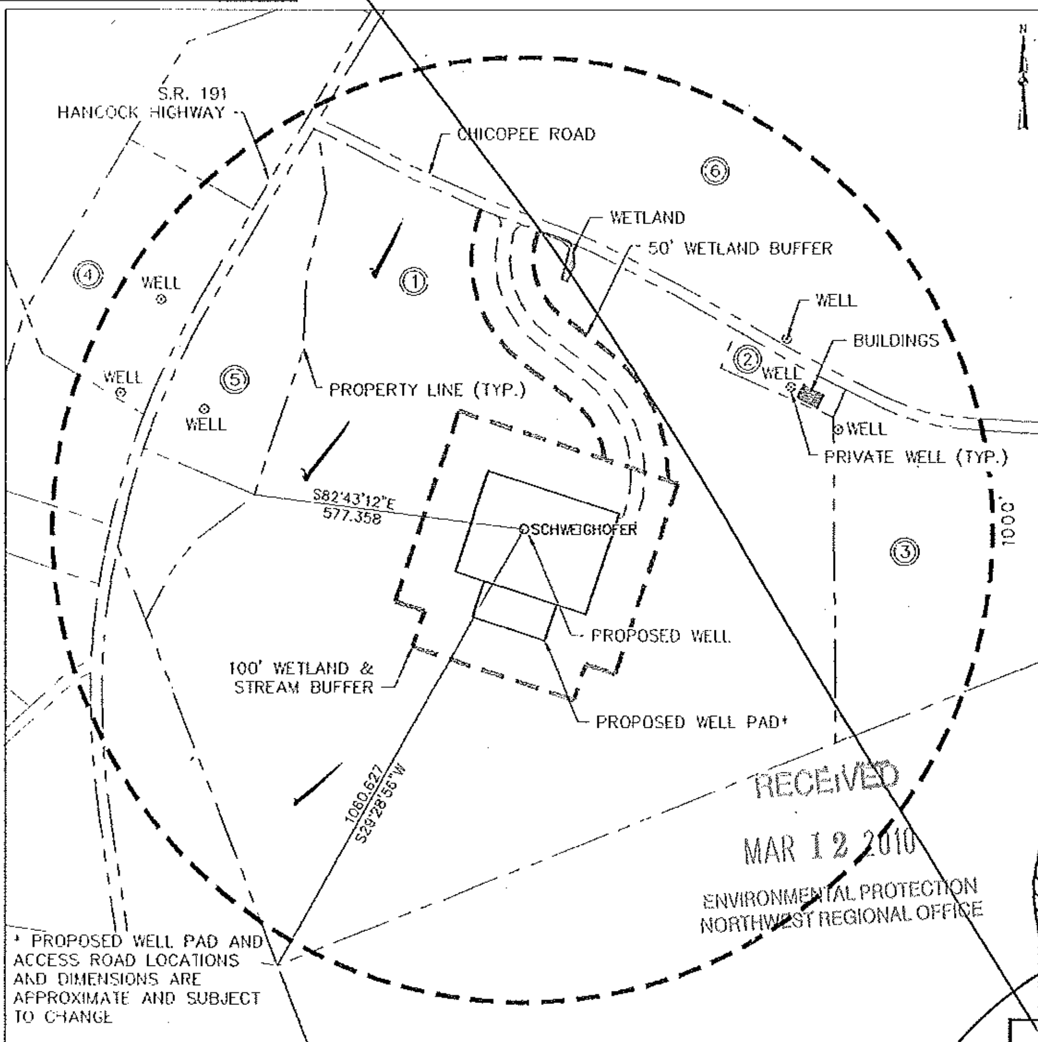
Denotes location of well on topo map.

Well is located on topo map 13,664 feet south of latitude 41° 47' 30"

True Latitude: NORTH
41°45' 15.0"

True Longitude: WEST
75° 10' 58.3"

Well is located on topo map 4,419 feet west of longitude 75° 10' 00"



1. N/F EDWARD M & MARIAN SCHWEIGHOFER 006291 37.463939
2. N/F JEFFERY R HOLLOWAY 006307 0.447538
3. N/F SHEILA A BOCHICCHIO 112935 9.400663
4. N/F PRAIRIE HILL HUNTING CLUB 006305 3.38604
5. N/F GREG RATTI 006306 3.072882
6. N/F EDWARD M & MARIAN SCHWEIGHOFER 006291 54.359303

Well Northing - Y
588790.223
Well Easting - X
2668860.3

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MAR 12 2010
ENVIRONMENTAL PROTECTION
NORTHWEST REGIONAL OFFICE

COMMONWEALTH OF PENNSYLVANIA
REGISTERED PROFESSIONAL
ALLAN R BERENBROK
ENGINEER
037282-E

Surveyor or Engineer: Tetra Tech   Phone #: 412-921-8873   Dwg #: 7   Date: 02-16-2010   Scale: 400   Tract Acreage:

Lat & Long Metadata		Elevation Metadata		Survey Date
Method GPS	Accuracy +/- 1 ft. Datum NAD83	Method GPS	Accuracy +/- 1 ft. Datum NAD 83	Jan 2010

Applicant / Well Operator Name	DEP ID#	Well (Farm) Name		Well #	Serial #
Newfield Appalachia PA LLC	277879	E.M. SCHWEIGHOFER		1-1	
Address		**County**	**Municipality**		**Well Type**
363 N. Sam Houston Parkway E., Suite 2020, Houston, TX, 77060		WAYNE	DAMASCUS		Test
Surface Landowner / Lessor		**USGS 7½' Quadrangle Map Name**		**Map Section**	**Surface Elevation**
Edward and Marian Schweighofer		LONG EDDY, NY 0444		8	1310.88 ft.
Target Formation(s)		**Angle & Course of Deviation (Drilling)**		**Anticipated Total Depth ft.**	
Onondaga		N/A		TVD 8350 ft.	TMD 8350 ft.

Surface Owner or Water Purveyor with a Water Supply within 1000 ft.	Approximate Course and Distance to Water Supply	Owner, Lessee, or Operator of Workable Coal Seam	Name of Coal Seam Owned, Leased, or Operated
Jeffrey Holloway	N62d 2' 10"E 646'	N/A	N/A
Sheila Bochicchio	N27d 28' 18"E 704'	N/A	N/A
Greg Ratti	N69d 26' 30"W 725'	N/A	N/A

5500-PM-OG0002-DWG Rev. 09/2008

pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Oil and Gas Management Program

WELL LOCATION PLAT

DEP USE ONLY	DEP Application Tracking #	G:
	Permit #	C:
	Project #	

Denotes location of well on topo map.

True Latitude: NORTH
41 ° 45 ' 15.0 "

True Longitude: WEST
75 ° 10 ' 58.3 "

WELL NORTHING - Y
588,790.22

WELL EASTING - X
2,668,860.31

Well is located on topo map 13,664 feet south of latitude 41 ° 47 ' 30 "

Well is located on topo map 4,419 feet west of longitude 75 ° 10 ' 00 "

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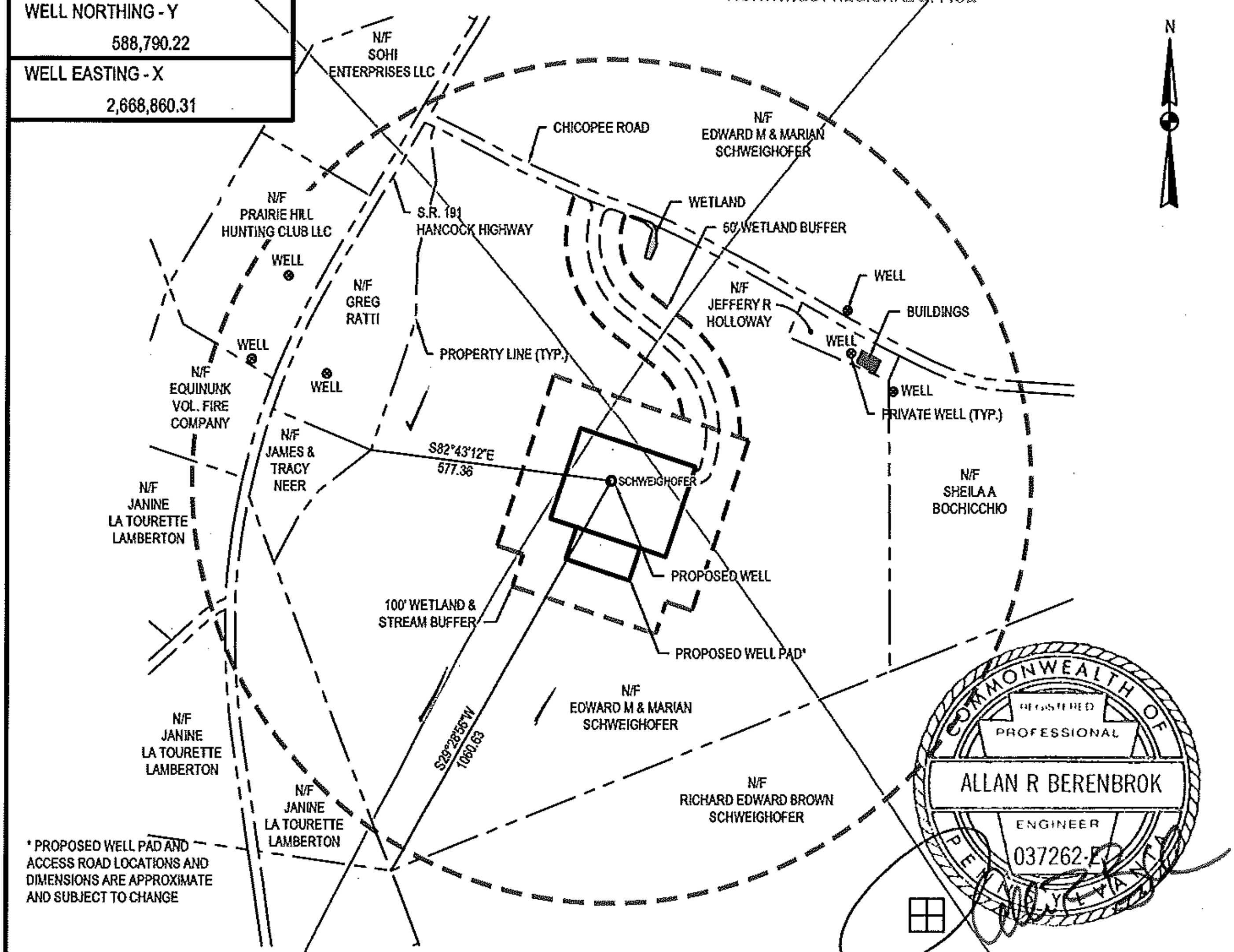
APR 12 2010
ENVIRONMENTAL PROTECTION
NORTHWEST REGIONAL OFFICE



COMMONWEALTH OF PENNSYLVANIA
REGISTERED PROFESSIONAL
ALLAN R BERENBROK
ENGINEER
037262-E

Surveyor or Engineer TETRA TECH Phone # (412) 921-8873 Dwg. # 1 Date 4/7/2010 Scale 1" = 400' Tract Acreage

Lat. & Long Metadata		Elevation Metadata	
Method GPS Accuracy +/- 1 ft. Datum NAD83		Method GPS Accuracy +/- 1 ft. Datum NAD83	Survey Date Jan. 2010

Applicant / Well Operator Name: Newfield Appalachia PA LLC	Well(Farm) Name: E.M. Schweighofer	Well #: 1-1	Serial #:
Address: 363 N. Sam Houston Parkway E., Suite 2020, Houston, TX 77060	County - Code: Wayne	Municipality: Damascus	Well Type: Vertical Test
Surface Landowner / Lessor: Edward and Marian Schweighofer	USGS 7 1/2 Quadrangle Map Name: Long Eddy, NY	Map Section: 8	Surface Elevation: 1310.88 ft.
Target Formation(s): Onondaga	Angle & Course of Deviation (Drilling): N/A	Anticipated Total Depth: TVD 8350 ft.	TMD 8350 ft.

Surface Owner or Water Purveyor with a Water Supply within 1,000 ft.	Approximate Course and Distance to Water Supply	Owner, Lessee, or Operator of Workable Coal Seam	Name of Coal Seam Owned, Leased, or Operated
Jeffery Holloway	N62d 2' 10"E 646'	N/A	N/A
Sheila Bochicchio	N27d 28' 18"E 704'	N/A	N/A
Greg Ratti	N69d 26' 30"W 725'	N/A	N/A
Prairie Hill Hunting Club LLC	N71d 20' 29"W 907'	N/A	N/A

R:_Marcellus Shale Projects\Newfield\2679 - Newfield Wells\Well Plat Permits\Permit Drawings\Schweighofer Well Pad Plat Exhibit A.dwg PIT BEN.HOPPE 4/9/2010 9:11:31 AM

Tetra Tech NUS
Foster Plaza 7
661 Andersen Drive
Pittsburgh, PA 15220-2745
Tel: (412) 921-7090
Fax: (412) 921-4040

LETTER OF TRANSMITTAL

DATE: 16 April 2010	JOB NO.: 112C02679
ATTENTION: Aaron O'Hara	
RE: Newfield – Teeple 1-1 and Schweighofer Well Plat	

TO

Pa DEP Northwest Regional Office
230 Chestnut Street
Meadville, Pa 16335
814-332-6870

WE ARE SENDING YOU [X] Attached [ ] Under separate cover via ________ the following items:

[ ] Shop drawings [ ] Prints [ ] Plans [ ] Samples [ ] Specifications

[ ] Copy of letter [ ] Change order [ ] ____________________

COPIES	DATE	NO.	DESCRIPTION
1			Teeple Well Plat 1-1 – sealed original
1			Schweighofer Well Plat – sealed original

THESE ARE TRANSMITTED as checked below:

[ ] For approval [ ] Approved as submitted [ ] Resubmit ___ copies for approval

[x] For your use [ ] Approved as noted [ ] Submit ____copies for distribution

[ ] As requested [ ] Returned for corrections [ ] Return ____ corrected prints

[ ] For review and comment [ ] For Your Signature

[ ] **FOR BIDS DUE** ______________ 19 ___ [ ] **PRINTS RETURNED AFTER LOAN TO US**

REMARKS:

Attached is the revised original Teeple and Schweighofer well plat with the revisions based upon our telephone conversation on 16 April 2010. Should you require any additional information, please contact me (412) -921-8873 at any time.

SIGNED ____________________

Allan R. Berenbrok, P.E.

CC: file (w/a)
Andrew Strassner (w/a)
Don Sleeth (w/a)

RECEIVED
APR 19 2010
ENVIRONMENTAL PROTECTION
NORTHWEST REGIONAL OFFICE

Phone Contact Log

Date/Time: 4/5/10 **Permit Number(s):** 127-20015

Company: Tetra Teck

Contact: Betsy Collins

Phone: 412-921-8250

Deficiencies Addressed:

Bochicchio course and distance to water supply

Bochicchio signature

topo mark

wetland < 1 acre ?

4/12/10 New plats received - Bochicchio water supply

left Message Allen Berenbrok 412-921-8873 4/16/10

4/19/10 New plats Received

Denial Date:

5500-PM-OG0002-DWG Rev. 09/2008

pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Oil and Gas Management Program

WELL LOCATION PLAT

DEP USE ONLY	DEP Application Tracking #	G: Pro 4/12/10
	Permit # 127-20015	
	Project #	C:

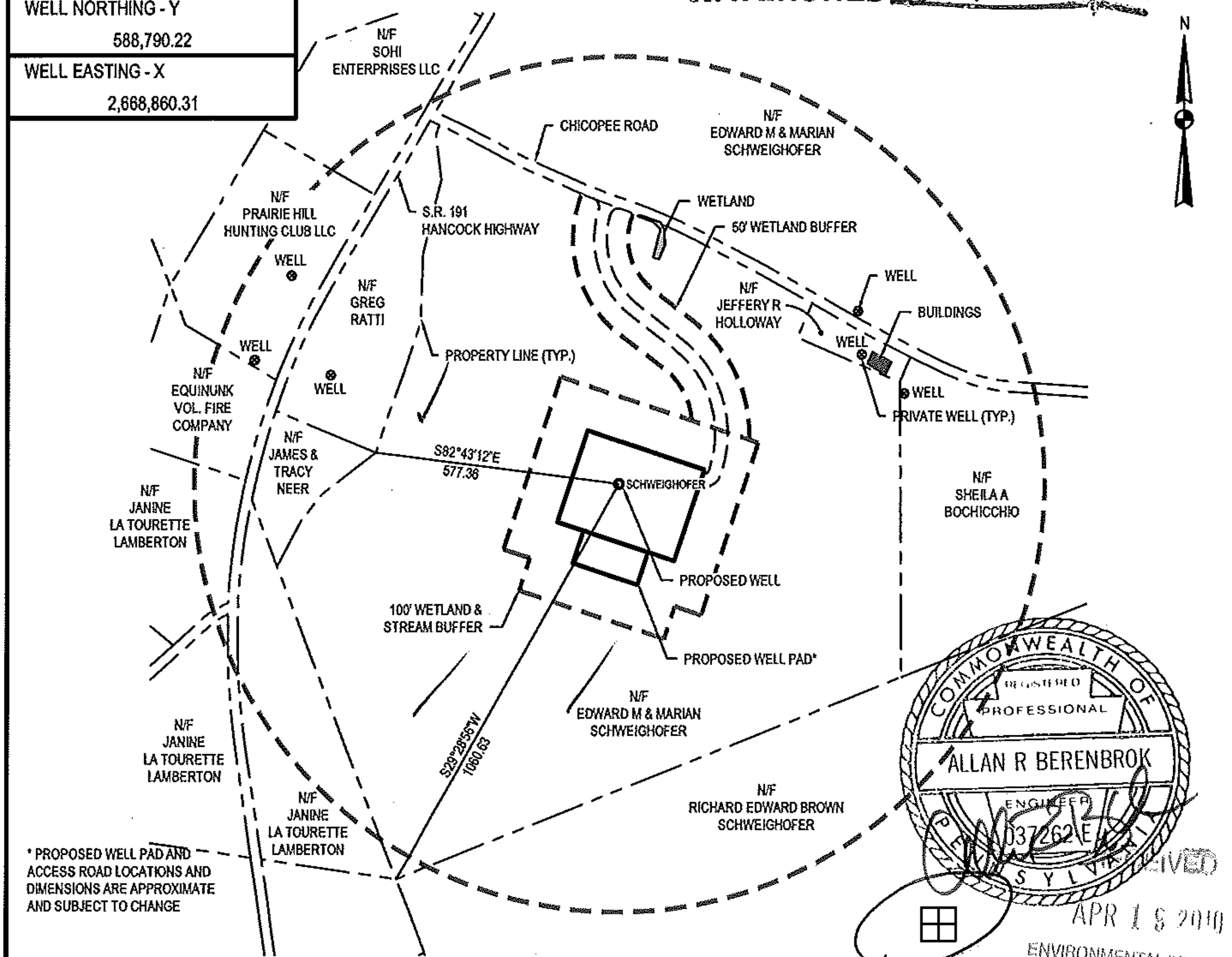
Denotes location of well on topo map.

Well is located on topo map 13,664 feet south of latitude 41 ° 47 ' 30 "

Well is located on topo map 4,419 feet west of longitude 75 ° 10 ' 00 "

True Latitude: NORTH
41 ° 45 ' 15.0 "
True Longitude: WEST
75 ° 10 ' 58.3 "
WELL NORTHING - Y
588,790.22
WELL EASTING - X
2,668,860.31

HQ WATERSHED Little Equinunk Creek



* PROPOSED WELL PAD AND ACCESS ROAD LOCATIONS AND DIMENSIONS ARE APPROXIMATE AND SUBJECT TO CHANGE

COMMONWEALTH OF PENNSYLVANIA REGISTERED PROFESSIONAL ALLAN R BERENBROK ENGINEER 037262E

RECEIVED APR 16 2010 ENVIRONMENTAL PROTECTION NORTHWEST REGIONAL OFFICE

Surveyor or Engineer TETRA TECH Phone # (412) 921-8873 Dwg. # 1 Date 4/16/2010 Scale 1" = 400' Tract Acreage

Lat. & Long Metadata Method GPS Accuracy +/- 1 ft. Datum NAD83	Elevation Metadata Method GPS Accuracy +/- 1 ft. Datum NAD83 Survey Date Jan. 2010
Applicant / Well Operator Name Newfield Appalachia PA LLC	Well(Farm) Name E.M. Schweighofer; Well # 1-1; Serial #
Address 363 N. Sam Houston Parkway E., Suite 2020, Houston, TX 77060	County - Code Wayne; Municipality Damascus; Well Type Vertical Test
Surface Landowner / Lessor Edward and Marian Schweighofer	USGS 7 1/2 Quadrangle Map Name Long Eddy, NY; Map Section 8; Surface Elevation 1310.88 ft.
Target Formation(s) Onondaga	Angle & Course of Deviation (Drilling) N/A; Anticipated Total Depth TVD 8350 ft. TMD 8350 ft.

Surface Owner or Water Purveyor with a Water Supply within 1,000 ft.	Approximate Course and Distance to Water Supply	Owner, Lessee, or Operator of Workable Coal Seam	Name of Coal Seam Owned, Leased, or Operated
Jeffery Holloway	N62d 2' 10"E 646'	N/A	N/A
Sheila Bochicchio	N72d 28' 18"E 704'	N/A	N/A
Greg Ratti	N69d 26' 30"W 725'	N/A	N/A
Prairie Hill Hunting Club LLC	N71d 20' 29"W 907'	N/A	N/A

R:_Marcellus Shale Projects\Newfield\2679 - Newfield Wells\Well Plat Permits\Permit Drawings\Schweighofer Well Pad Plat Exhibit A.dwg PIT BEN.HOPPE 4/16/2010 12:42:29 PM

5500-FM-OG0002-DWG Rev. 09/2008

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DEPARTMENT OF ENVIRONMENTAL PROTECTION

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Oil and Gas Management Program

WELL LOCATION PLAT

(Attachment, if needed)

DEP USE ONLY	
DEP Application Tracking #	G: ACO 4/19/10
Permit # 127-20015	C:
Project #	

Use only if you need additional space for listings.

Applicant / Well Operator Name	Well(Farm) Name	Well #	Serial #
Newfield Appalachia PA LLC	E.M. Schweighofer	1-1	

Surface Owner or Water Purveyor with a Water Supply within 1,000 ft.	Approximate Course and Distance to Water Supply	Owner, Lessee, or Operator of Workable Coal Seam	Name of Coal Seam Owned, Leased, or Operated
Prairie Hill Hunting Club LLC	N57d 42' 43"W 913'	N/A	N/A
Edward and Marian Schweighofer	N54d 14' 30"E 692'	N/A	N/A

RECEIVED
APR 19 2010
ENVIRONMENTAL PROTECTION
NORTHWEST REGIONAL OFFICE

R:_Marcellus Shale Projects\Newfield\2679 - Newfield Wells\Well Plat Permits\Permit Drawings\Schweighofer Well Pad Plat Exhibit C.dwg PIT BEN.HOPPE 4/9/2010 9:12:08 AM

5500-FM-OG0001A Rev. 11/2007

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL AND GAS MANAGEMENT PROGRAM

	DEP USE ONLY	
Permittee's eFACTS ID 277879		Auth ID 827248
Watershed Name Little Equinunt Creek		HQ

WELL PERMIT

Permittee	OGO #	Permit Number	Date Issued
NEWFIELD APPALACHIA PA LLC	OGO-67425	37-127-20015-	05/07/2010
Address 363 N SAM HOUSTON PKWY E STE 2020		Farm Name & Well Number EM SCHWEIGHOFER 1 1	Well Serial #
		Municipality Damascus	County Wayne
HOUSTON, TX 77060-2424		7½ ' Quadrangle Name Long Eddy	Map Section # 8
Phone (281) 847-6031	Project #	Latitude 41-45-15.0000	Longitude -75-10-58.3000
Surf Elev at Site 1311 feet	Anticipated Total Depth 8350 feet / Well Type TE	Offset distances referenced to NE corner of map section. South 13664 feet	West 4419 feet

This permit covering the well operator and well location shown above is evidence of permission granted to conduct activities in accordance with the Oil and Gas Act and the Oil and Gas Conservation Law, if the well is subject to that act and any rules and regulations promulgated thereunder, subject to the conditions contained herein and in accordance with the application submitted for this permit. This permit does not convey any property rights.

This permit and the permittee's authority to conduct the activities authorized by this permit are conditioned upon operator's compliance with applicable law and regulations.

Notification must be given to the district oil and gas inspector, the surface landowner and political subdivision of the date well drilling will begin at least 24 hours prior to commencement of drilling activities.

The permittee hereby authorizes and consents to allow, without delay, employees or agents of the Department to have access to and to inspect all areas upon presentation of appropriate credentials, without advance notice or a search warrant. This includes any property, facility, operation or activity governed by the Oil and Gas Act, the Oil and Gas Conservation Law, the Coal and Gas Resource Coordination Act and other statutes applicable to oil and gas activities administered by the Department. The authorization and consent shall include consent to the Department to collect samples of wastewaters or gases, to take photographs, to perform measurements, surveys, and other tests, to inspect any monitoring equipment, to inspect the methods of operation and disposal, and to inspect and copy documents required by the Department to be maintained. The authorization and consent includes consent to the Department to examine books, papers, and records pertinent to any matter under investigation pursuant to the Oil and Gas Act or pertinent to a determination of whether the operator is in compliance with the above referenced statutes. This condition in no way limits any other powers granted to the Department under the Oil and Gas Act and other statutes, rules and regulations applicable to these activities as administered by the Department.

This permit does not relieve the operator from the obligation to comply with the Clean Streams Law and all statutes, rules and regulations administered by the Department.

Special Permit Conditions:

This permit expires **05/07/2011** unless drilling is commenced on or before that date and prosecuted with due diligence.

S. Craig Lobins

Regional Oil and Gas Program Manager

Stephen Watson
Oil & Gas Inspector

2 Public Square
Wilkes-Barre, PA 18711-0790

570-826-2320
Telephone

5500-FM-OG0004 Rev. 1/2010

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DEPARTMENT OF ENVIRONMENTAL PROTECTION

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL AND GAS MANAGEMENT PROGRAM

DEP USE ONLY	
Site ID	Primary Fac ID 728807
Client Id 277879	Subfacility Id

Well Record and Completion Report

Well Operator NEWFIELD APPALACHIA PA LLC	DEP ID# 277879	Well API # (Permit / Reg) 37-127-20015-	Project Number	Acres
Address 363 N SAM HOUSTON PKWY E STE 2020,		Well Farm Name & Well # EM SCHWEIGHOFER 1 1		Serial #
City HOUSTON	State TX	Zip Code 77060-2424	County Wayne	Municipality Damascus
Phone (281) 847-6031	Fax	USGS 7.5 min. quadrangle map Long Eddy		

Check all that apply: ☐ Original Well Record ☐ Original Completion Report ☐ Amended Well Record ☐ Amended Completion Report

WELL RECORD Also complete the Log of Formations on back (page 2)

Well Type ☐ Gas ☐ Oil ☐ Combination Oil & Gas ☐ Injection ☐ Storage ☐ Disposal

Drilling Method ☐ Rotary – Air ☐ Rotary – Mud ☐ Cable Tool

Date Drilling Started	Date Drilling Completed	Surface Elevation	Total Depth – Driller	Total Depth - Logger
		ft.	ft.	ft.

Casing and Tubing

Cement returned on surface casing? ☐ Yes ☐ No
Cement returned on coal protective casing? ☐ Yes ☐ No ☐ N/A

Hole Size	Pipe Size	Wt.	Thread / Weld	Amount in Well (ft)	*Material Behind Pipe* Type and Amount	*Packer / Hardware / Centralizers* Type	Size	Depth	Date Run

COMPLETION REPORT

Perforation Record			Stimulation Record						
Date	Interval Perforated From	To	Date	Interval Treated	*Fluid* Type	Amount	*Propping Agent* Type	Amount	Average Injection

Natural Open Flow	Natural Rock Pressure		Hours	Days
After Treatment Open Flow	After Treatment Rock Pressure		Hours	Days

Well Service Companies -- Provide the name, address, and phone number of all well service companies involved.

Name	Name	Name
Address	Address	Address
City - State – Zip	City - State – Zip	City - State – Zip
Phone	Phone	Phone

LOG OF FORMATIONS

Well API#: 37-127-20015--

(If you will need more space than this page, please photocopy the blank form before filling it in.)

Formation Name or Type	Top (feet)	Bottom (feet)	Gas at (feet)	Oil at (feet)	Water at (fresh / brine; ft.)	Source of Data

I do hereby certify to the best of my knowledge, information and belief that the well identified on this Well Record and Completion Report has been properly cased and cemented in accordance with the requirements of 25 Pa. Code Chapter 78 and any conditions contained in the permit for this well. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.

Well Operator's Signature	**DEP USE ONLY**
	Reviewed by: Date:
Title: Date:	Comments:

5500-FM-OG0075 Rev. 8/2001

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL AND GAS MANAGEMENT PROGRAM

DEP USE ONLY	
Site ID	Primary Fac ID 728807
Client Id 277879	Subfacility Id

Well Site Restoration Report

A. Operator and Well Information

Please read instructions on back before completing this form.

Well Operator: NEWFIELD APPALACHIA PA LLC	DEP ID#: 277879	Well API # (Permit / Reg): 37-127-20015-	
Address: 363 N SAM HOUSTON PKWY E STE 2020,		Well Farm Name & Well #: EM SCHWEIGHOFER 1 1	Serial #
City: HOUSTON	State: TX / Zip Code: 77060-2424	County: Wayne	Municipality: Damascus
Phone: (281) 847-6031	Fax		

B. Land Application of Tophole Water

Date applied	pH
Volume (bbls)	Spec. cond. (µmhos/cm)

C. Off-site Waste Disposal

Type: ☐ Drilling Fluid (803) **Amount:** bbls

☐ Fracing Fluid (804) bbls

☐ Other, specify: **Qty:** bbls or tons

Method of disposal or reuse

☐ Sewage Treatment Plant (10)

☐ Disposal Well (04) ☐ Brine Treatment Plant (12)

☐ Landfill (05) ☐ Other (08)

Facility Information

Name | Permit #

Hauler Information

Name

Address

City | State | Zip Code

D. On-site Disposal – Drill Cuttings or Waste

Location of center of disposal area in relation to the well:

Course degrees | Distance feet

Describe the **material disposed**, including additives.

Specify disposal method

☐ Unlined pit, complete Section E. ☐ Dusting

☐ Lined pit, complete Section E. ☐ Solidification

☐ Land application, complete Section F. ☐ Other

E. Pit Disposal

Describe pit closure procedures.

Subbase, material: Thickness: inches

Pit liner, material: Thickness: mils

Pit dimensions (feet) Length: Width: Depth:

F. Land Application

Area: Length: feet Width: feet

Waste-to-soil ratio (by volume):

Chemical analysis of waste

Cadmium (Cd)	ppm	Nickel (Ni)	ppm
Copper (Cu)	ppm	Zinc (Zn)	ppm
Chromium (Cr)	ppm	Oil and Grease	%
Lead (Pb)	ppm	Spec. Cond.	µmhos/cm
Mercury (Hg)	ppm		

Well Operator's Signature

Title: Date:

DEP USE ONLY

Reviewed by: Date:

Comments:

Instructions for Well Site Restoration Report

Form 5500-FM-OG0075

Use this form to file the Well Site Restoration Report as required under 25 Pa. Code § 78.65(3). This report is to be filed with the department within 60 days after the restoration of the well site.

Section A. Operator and Well Information

Enter the name, address and telephone number of the well operator/permittee.

Provide the requested well information.

Section B. Land Application Of Tophole Water

Land application of tophole water must be performed in accordance with 25 Pa. Code § 78.60.

Provide the date(s) when tophole water was applied to the land, the estimated volume discharged, and the pH and specific conductance readings of the tophole water.

Section C. Off-site Waste Disposal

If disposing of residual waste off-site, complete this section.

Check the box next to each type of waste taken off-site for disposal. More than one box may be checked. Identify the number of barrels of drilling or fracing fluid removed. If checking "other", identify the waste and show the amount in either barrels or tons. Circle the appropriate unit of measurement.

Check the box next to the type of facility or site receiving the waste. Provide the name and permit number of the facility.

Provide the name and address of the person or company hauling the waste.

Section D. On-site Disposal – Drill Cuttings or Waste

If disposing of drill cuttings and/or residual waste on-site in accordance with 25 Pa. Code § 78.61 (Disposal of drill cuttings), § 78.62 (Disposal of residual waste—pits), or § 78.63 (Disposal of residual waste—land application), complete this section.

Locate the approximate center of the disposal area by giving the course in degrees and the distance in feet from the wellhead.

Describe the types of materials that were disposed on-site. Include drill cuttings above the surface casing seat, drill cuttings below the surface casing seat, cement returns, drilling muds, frac sands, and any other material that is being disposed on-site. Indicate any additives that were in the materials being disposed.

Additives are usually present to modify the performance of cement, drilling muds or frac sands. An example might be salt or oil in drilling muds.

Check the box next to the on-site disposal methods used. If "other" is checked, briefly describe the method of disposal.

Section E. Pit Disposal

If disposing of drill cuttings under 25 Pa. Code § 78.61 (Disposal of drill cuttings) complete the pit dimensions part of this section. If disposing of drill cuttings and/or residual waste under 25 Pa. Code § 78.62 (Disposal of residual waste—pits), complete all of this section.

Describe the procedures used to close the pit. The procedures should conform to requirements in 25 Pa. Code § 78.62.

Describe the type of material and thickness used for the subbase and pit liner. The manufacturer should be identified when describing the type of material used for the pit liner.

Provide the dimensions of the pit, giving the appropriate length, width, and depth in feet.

Section F. Land Application

If disposing of drill cuttings and/or residual waste including contaminated drill cuttings under 25 Pa. Code § 78.63, complete this section.

Provide the approximate length and width of the land application area in feet. Indicate the ratio of waste to soil by volume. As an example, if a 3-inch layer of waste was mixed into a 6-inch layer of soil the ratio would be 1/2. In no case may the ratio exceed 1/1.

Complete the chemical analysis information if it is requested by the department. The analysis is to be performed on the waste soil mixture after land application has occurred. See the guidelines for land application in the "Oil and Gas Operators Manual" for taking samples and for analysis methods.

If more room is needed to complete any section, provide the information on 8 ½" by 11" sheets of paper and attach to this form. Indicate the sections the information applies to.

Please note that the most recent revision of the Application for Drilling or Altering a Well must be submitted with all drilling applications. Please check the website below for the most recent revisions for all forms.
http://www.dep.state.pa.us/dep/deputate/minres/oilgas/o_gforms.htm

The Erosion, Sediment& Storm water Control Module is no longer being accepted for ESCGP-1 applications. Please submit the complete ESCGP-1 application for any projects. The most recent revisions must be submitted along with the application fee of $500.00

pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION
NORTHWEST REGIONAL OFFICE

Dear Operator:

Enclosed please find well permit(s) issued for drilling or altering a well. Developing this resource in a safe and environmentally protective manner is of utmost importance. As you may be aware, there have been several recent incidences where water supplies have been affected by natural gas migration. In order to prevent future impacts to the Commonwealth's water resources and provide a mechanism for ensuring public safety, the Department is providing the following information as a reminder of the cementing requirements for oil and gas wells.

Cementing

Properly cementing the casing of a well is critical to protecting water resources, preventing gas migration, and ensuring well integrity. If the casing is improperly cemented or if insufficient cement is used, such as when cement is not returned to the surface, the operator should notify the Department pursuant to 25 Pa. Code § 78.86.

In addition, when cementing surface casing, 25 Pa. Code § 78.85 states that the cement must be allowed to set for at least 8 hours *and* until the cement attains a compressive strength of at least 350 psi. While the cement is setting, the casing must not be disturbed. This includes any activity that may cause movement or pressure changes to the casing or the cement sheath surrounding the casing. After the cement is set, care must be taken when drilling through the plug to prevent damaging the seal at the casing seat. Disturbing the casing while cement is setting or damaging the seal at the casing seat may provide a mechanism for gas and other fluids to escape from the well and contaminate groundwater and water supplies. If this occurs, the operator must notify the Department.

In addition, the Department also reminds you of the following reporting requirements for oil and gas wells.

Reporting

1. Pursuant to Section 212(b) of the Oil and Gas Act and Section 78.122(a) of Chapter 78 of the Oil and Gas Regulations, a **Well Record** must be submitted to the Department within thirty (30) days of cessation of drilling or altering a well.

2. Pursuant to Section 212(b) of the Oil and Gas Act and Section 78.122(b) of Chapter 78 of the Oil and Gas Regulations, a **Completion Report** must be submitted to the Department within thirty (30) days of completion of the well. A copy of the Well Record and Completion Report is enclosed with this letter. This is a newly revised form which requires the operator to certify that the well has been cased and cemented according to the requirements of 25 Pa. Code Chapter 78. Well Record and Completion Report forms that do not contain this certification will not be accepted by the Department. Additional copies of this form can be obtained from the Department's eLibrary at http://www.elibrary.dep.state.pa.us/dsweb/View/Collection-9841

3. Pursuant to Section 212(a) of the Oil and Gas Act, a report specifying the well status and production on the most well-specific basis available is to be provided to the Department. Section 78.121 of Chapter 78 details the reporting time frames required for various well types, waste reporting, and the acceptable format for the **Well and Waste Production Report** submissions.

4. Also note that pursuant to Section 212(b) of the Oil and Gas Act, the Department has the authority to request and does hereby request you submit a digital copy on CD of **ALL Well Logs** (temperature, electrical, radioactive, gamma ray, neutron, induction, resistivity, multi-arm caliper, acoustic, optical, etc.) that have been run on this well.

The above records and logs are to be submitted to the Department of Environmental Protections, Oil and Gas Management, 230 Chestnut St., Meadville, Pa 16335-3481 to the attention of the Regional Oil and Gas Manager.

Thank you for your cooperation in this matter.

Sincerely,

S. Craig Lobins

S. Craig Lobins
Regional Manager
Oil and Gas Management

Authorization Search Details

Search again

Authorization ID:	841481
Permit number:	127-20011
Site:	STOCKPORT ASSN 1
Client:	PENNSWOOD OIL & GAS LLC
Authorization type:	Drill & Operate Well Permit
Application type:	Renewal
Authorization is for:	FACILITY
Date received:	07/06/2010
Status:	Issued 07/20/2010

Sub-Facilities for Authorization

Sub-Facility ID	Sub-Facility Name	Description	eMap PA Location
994272	STOCKPORT ASSN 1	Well	View Map in eMapPa (IE-only)

Log in to DEP's eNOTICE to track this permit with automatic email updates

Authorization Search Details

Search again

Authorization ID:	796670
Permit number:	127-20011
Site:	STOCKPORT ASSN 1
Client:	PENNSWOOD OIL & GAS LLC
Authorization type:	Drill & Operate Well Permit
Application type:	New
Authorization is for:	FACILITY
Date received:	06/15/2009
Status:	Issued 07/22/2009

Sub-Facilities for Authorization

Sub-Facility ID	Sub-Facility Name	Description	eMap PA Location
994272	STOCKPORT ASSN 1	Well	View Map in eMapPa (IE-only)

Log in to DEP's eNOTICE to track this permit with automatic email updates

Authorization Search Details

Search again

Authorization ID:	792478
Permit number:	127-20010
Site:	PRESTON 38 LLC OG WELL
Client:	PENNSWOOD OIL & GAS LLC
Authorization type:	Drill & Operate Well Permit
Application type:	New
Authorization is for:	FACILITY
Date received:	05/15/2009
Status:	Issued 07/29/2009

Sub-Facilities for Authorization

Sub-Facility ID	Sub-Facility Name	Description	eMap PA Location
991872	PRESTON 38 LLC	Well	View Map in eMapPa (IE-only)

Log in to DEP's eNOTICE to track this permit with automatic email updates

Authorization Search Details

Search again

Authorization ID:	841478
Permit number:	127-20010
Site:	PRESTON 38 LLC OG WELL
Client:	PENNSWOOD OIL & GAS LLC
Authorization type:	Drill & Operate Well Permit
Application type:	Renewal
Authorization is for:	FACILITY
Date received:	07/06/2010
Status:	Issued 07/20/2010

Sub-Facilities for Authorization

Sub-Facility ID	Sub-Facility Name	Description	eMap PA Location
991872	PRESTON 38 LLC	Well	View Map in eMapPa (IE-only)

Log in to DEP's eNOTICE to track this permit with automatic email updates

5500-FM-OG0001, 11/2007

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL AND GAS MANAGEMENT PROGRAM

WELL PERMIT

DEP USE ONLY	
Permittee's eFACTS ID: 261535	Auth ID: 715410
Watershed Name:	Quality:

Permittee: STONE ENERGY CORPORATION	OGO.#: OGO-66630	Permit Number: 37-127-20007-00	Date Issued: 04/28/2008
Address: PO BOX 5280		Farm Name & Well Number: GEUTHER 1	Well Serial #:
		Municipality: Clinton	County: Wayne
LAFAYETTE, LA 70506		7½ ' Quadrangle Name: Forest City	Map Section #: 5
Phone: (337) 237-0410	Project #:	Latitude: 41-41-3.7400	Longitude: -75-26-10.8600
Surf Elev at Site: 2210 feet	Anticipated Total Depth: 8150 feet / Well Type: GS	Offset distances referenced to NE corner of map section: South 8,703 feet	West 5377 feet

This permit covering the well operator and well location shown above is evidence of permission granted to conduct activities in accordance with the Oil and Gas Act and the Oil and Gas Conservation Law, if the well is subject to that act and any rules and regulations promulgated thereunder, subject to the conditions contained herein and in accordance with the application submitted for this permit. This permit does not convey any property rights.

This permit and the permittee's authority to conduct the activities authorized by this permit are conditioned upon operator's compliance with applicable law and regulations.

Notification must be given to the district oil and gas inspector, the surface landowner and political subdivision of the date well drilling will begin at least 24 hours prior to commencement of drilling activities.

The permittee hereby authorizes and consents to allow, without delay, employees or agents of the Department to have access to and to inspect all areas upon presentation of appropriate credentials, without advance notice or a search warrant. This includes any property, facility, operation or activity governed by the Oil and Gas Act, the Oil and Gas Conservation Law, the Coal and Gas Resource Coordination Act and other statutes applicable to oil and gas activities administered by the Department. The authorization and consent shall include consent to the Department to collect samples of wastewaters or gases, to take photographs, to perform measurements, surveys, and other tests, to inspect any monitoring equipment, to inspect the methods of operation and disposal, and to inspect and copy documents required by the Department to be maintained. The authorization and consent includes consent to the Department to examine books, papers, and records pertinent to any matter under investigation pursuant to the Oil and Gas Act or pertinent to a determination of whether the operator is in compliance with the above referenced statutes. This condition in no way limits any other oowers granted to the Department under the Oil and Gas Act and other statutes, rules and regulations applicable to these activities as administered by he Department.

his permit does not relieve the operator from the obligation to comply with the Clean Streams Law and all statutes, rules and regulations administered y the Department.

pecial Permit Conditions:

is permit expires **04/28/2009** unless drilling is commenced on or before that date and prosecuted with due diligence.

S. Craig Lobin
Regional Oil and Gas Program Manager

RB KARLINSEY	P O Box 673, Coudersport, PA 16915-0673	814-274-3611
and Gas Inspector	Address	Telephone

5500-PM-OG0001 Rev. 9/2007

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL & GAS MANAGEMENT PROGRAM

DEP USE ONLY	
AUTH #	CNC
Check # 1198	Amount $ 350.00

PERMIT APPLICATION FOR DRILLING OR ALTERING A WELL

DEP USE ONLY			
Notes	OGO # 66630	Objection Date - Do not issue before: 4-17-08	Well Permit # 127-20007
	Bond # 11503		Special Cond. A B C D E F
	C: 3/10/08 pal & AB 4/18/08	Date Approved: ar	Watershed Name:
	INV: 4-28-08		Designation: HQ EV

Please read instructions before you begin filling in this form.

Applicant (Operator) Name	DEP Client ID#	Phone	FAX	Check if new address. ☐
STONE ENERGY CORPORATION		337-237-0410	337-237-0426	
Mailing Address (Street or PO Box): P.O. Box 5280	City: Lafayette	State: LA	Zip +4: 70506	Country (if not USA)

(Well) Farm Name	Well #	Serial #
Geuther	1	
County: WAYNE	Municipality: CLINTON	Project # (from DEP)

If you are applying for a permit to redrill, drill deeper, or alter a well that was previously permitted or registered, ***or for a well site that was previously permitted but not drilled,*** check this box ☐ and enter the permit or registration number here:

If applying for a permit to rework an existing well not registered or permitted, check this box ☐ and **enter date drilled**, if known:_______________ (see instructions)

PNDI Attached: ☒ Any "hit" must include accepted mitigation plan from applicable agency.

PERMIT TYPE Check one.
Application is to:
☒ Drill a new well
☐ Deepen a well
☐ Redrill a well
☐ Alter a well
☐ Other (specify)

TYPE OF WELL Check one.
☒ Gas
☐ Oil
☐ Comb. (gas & oil)
☐ Injection, recovery
☐ Disposal
☐ Coalbed Methane
☐ Gas Storage
☐ Other (specify)

APPLICATION FEE Check one.
☒ $ 350 (Gas; Comb.; Coal Meth; Storage)
☐ $ 250 (Oil; Inj– Rec)
☐ $ 150 (Injection – Waste Disposal)
☐ $ 100 (Redrill, Drill Deeper, Alter a Well, or Change Use)
☐ $ 0 (Rehab orphan)

COORDINATION WITH REGULATIONS AND OTHER PERMITS	Yes	No
1. Will the well be subject to the **Oil and Gas Conservation Law**? If "No," go to 2).	☒	
a. If "Yes" to #1, is the well at least 330 feet from outside lease or unit boundary?	☒	☐
b. Does the location fall within an area covered by a spacing order?	☐	☒
2. Will the well penetrate a **workable coal seam**? If "No," include justification and supporting documentation.	☐	☒
3. If the well will penetrate a **workable coal seam**, and the well is a "non-conservation" gas well, does the location comply with the distance requirements of Section 7 of the Coal and Gas Resource Coordination Act? (At least 1,000 feet from all existing wells).	☐	☐
a. If "No," is the required exception request attached? (Check here if re-working an existing well: ☐ N/A)	☐	☐
4. Will the well be drilled at a location where the **coal** has been **removed**?	☐	☒
5. Will the well be drilled through an **active (operating or projected) coalmine**, or within 1,000 feet of the boundary?	☐	☒
a. If "Yes," print the names of: Mine: Operator:		
6. Will the well penetrate or be within 2,000 feet of an active **gas storage reservoir boundary**?	☐	☒
a. If Yes, print the names of: Storage Field: Operator:		
7. Is the proposed well location within the permitted area of a **landfill**?	☐	☒
8. Will the well site be within 100 feet (measured horizontally) of a **stream, spring or body of water** identified on the most current 7½' topographic map?	☐	☒
a. If "Yes," is a request for a waiver (form 5500-FM-OG0057), and E&S control plan attached?	☐	☐
9. Will the well site be within 100 feet **of a wetland** or in **a wetland**?	☐	☒
a. Is the well site within 100 feet of a wetland greater than one acre in size?	☐	☐
If yes, is a waiver request (form 5500-FM-OG0057) and E&S control plan attached?	☐	☐
10. Will the well be drilled within 200 feet (horizontally) from any existing **building** or an existing **water supply**?	☐	☒
a. If "Yes," is written consent from the owner attached?	☐	☐
b. If written consent is not attached, is a variance request (form 5500-FM-OG0058) attached?	☐	☐
11. Will the well be located where it may impact a public resource as outlined in the "**Coordination of a Well Location with Public Resources**" form 5500-PM-OG0076? If yes, attach a competed copy of the form.	☐	☒
12. Is the well site in a **Special Protection** High Quality (HQ) or Exceptional Value (EV) watershed?	☐	☒
13. Is this well part of a development where you need an **Earth Disturbance Permit** for Oil and Gas Activities disturbing more than 5 acres?	☐	☒

DEP USE ONLY
Date Stamps/Notes
Auth 715410
Site 702466
Clnt 261535
APS 639350
Acct 614142

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ENVIRONMENTAL PROTECTION
NORTHWEST REGIONAL OFFICE

Signature of Applicant The person signing this form attests that they have the authority to submit this application on behalf of the applicant, and that the information, including all related submissions, is true and accurate to the best of their knowledge.

Signature of Person Authorized to Submit Application	(Print or Type)	Name of Signer: Eric W. Rankinen Title: Regional Landman	Date 2/13/2008
Eric W. Rankinen			

Application Preparer/Contact: FOX AND FOX, INC. Phone: 814-745-2861

Forest City

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Oil and Gas Management Program

WELL LOCATION PLAT

DEP Application Tracking # APS# 639350 [initials] 4-18-08
Permit # 127-20007
Project #
C:

☐ Denotes location of well on topo map.

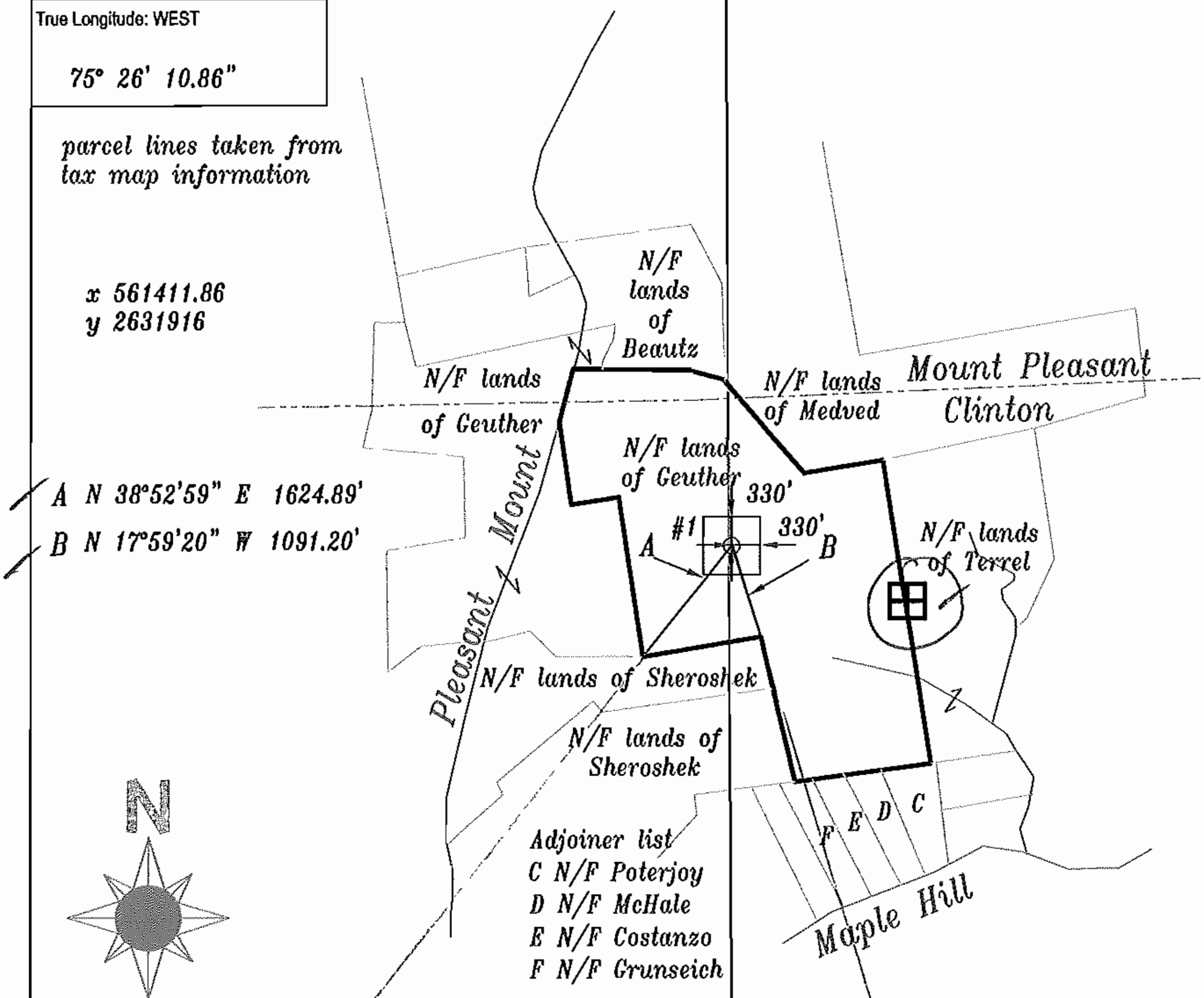
Well is located on topo map 8703 feet south of latitude 41 ° 42 ' 30 "

True Latitude: NORTH
41° 41' 03.74"

True Longitude: WEST
75° 26' 10.86"

Well is located on topo map 5377 feet west of longitude 75 ° 25 ' 00 "

parcel lines taken from tax map information



D. Michael Canada

Surveyor or Engineer: D. Michael Canada, Pa. Lic. # 029272 E	Phone # (716) 379-7918	Dwg. # 6669	Date January 30, 2008; Rev. Mar. 3, 2008	Scale 1" = 2000'	Tract Acreage 261

Lat. & Long Metadata: Method Static GPS; Accuracy ± 10 ft.; Datum NAD 27	Elevation Metadata: Method Scaled; Accuracy ± 10 ft.; Datum USGS Quad; Survey Date 1/30/2008
Applicant / Well Operator Name: Stone Energy Corporation	Well (Farm) Name: Geuther; Well # #1; Serial #
Address: PO Box 5280 Lafayette, LA 70506	County - Code: Wayne; Municipality: Clinton
Surface Landowner: Robert Geuther	USGS 7 1/2 Quadrangle Map Name: Forest City; Map Section 5
Surface Lessor	Angle & Course of Deviation (Drilling): Vertical 0; Surface Elevation 2210 ft.; Anticipated Total Depth 8150 ft.

Surface Owner or Water Purveyor with a Water Supply within 1,000 ft.	Approximate Course and Distance to Water Supply	Owner, Lessee, or Operator of Workable Coal Seam	Name of Coal Seam Owned, Leased, or Operated

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NORTHWEST REGIONAL OFFICE

5500-FM-OG0001A Rev. 11/2007

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL AND GAS MANAGEMENT PROGRAM

DEP USE ONLY	
Permittee's eFACTS ID 277879	Auth ID 826657
Watershed Name Shehawken Rattlesnake Creek	Quality HQ

WELL PERMIT

Permittee	OGO.#	Permit Number	Date Issued
NEWFIELD APPALACHIA PA LLC	OGO-67425	37-127-20013-	04/23/2010

Address 363 N SAM HOUSTON PKWY E STE 2020	Farm Name & Well Number: DL TEEPLE 1 1 / Well Serial #:
	Municipality: Manchester / County: Wayne
HOUSTON, TX 770602424	7½' Quadrangle Name: Long Eddy / Map Section #: 1
Phone: (281) 847-6031 / Project #:	Latitude: 41-49-39.9000 / Longitude: -75-11-53.3300
Surf Elev at Site: 1516 feet / Anticipated Total Depth: 8350 feet / Well Type: GS	Offset distances referenced to NE corner of map section. South 2304 feet West 8580 feet

This permit covering the well operator and well location shown above is evidence of permission granted to conduct activities in accordance with the Oil and Gas Act and the Oil and Gas Conservation Law, if the well is subject to that act and any rules and regulations promulgated thereunder, subject to the conditions contained herein and in accordance with the application submitted for this permit. This permit does not convey any property rights.

This permit and the permittee's authority to conduct the activities authorized by this permit are conditioned upon operator's compliance with applicable law and regulations.

Notification must be given to the district oil and gas inspector, the surface landowner and political subdivision of the date well drilling will begin at least 24 hours prior to commencement of drilling activities.

The permittee hereby authorizes and consents to allow, without delay, employees or agents of the Department to have access to and to inspect all areas upon presentation of appropriate credentials, without advance notice or a search warrant. This includes any property, facility, operation or activity governed by the Oil and Gas Act, the Oil and Gas Conservation Law, the Coal and Gas Resource Coordination Act and other statutes applicable to oil and gas activities administered by the Department. The authorization and consent shall include consent to the Department to collect samples of wastewaters or gases, to take photographs, to perform measurements, surveys, and other tests, to inspect any monitoring equipment, to inspect the methods of operation and disposal, and to inspect and copy documents required by the Department to be maintained. The authorization and consent includes consent to the Department to examine books, papers, and records pertinent to any matter under investigation pursuant to the Oil and Gas Act or pertinent to a determination of whether the operator is in compliance with the above referenced statutes. This condition in no way limits any other powers granted to the Department under the Oil and Gas Act and other statutes, rules and regulations applicable to these activities as administered by the Department.

This permit does not relieve the operator from the obligation to comply with the Clean Streams Law and all statutes, rules and regulations administered by the Department.

Special Permit Conditions:

This permit expires **04/23/2011** unless drilling is commenced on or before that date and prosecuted with due diligence.

Stacie Gustafson for S. Craig Lobins
Regional Oil and Gas Program Manager

Stephen Watson
Oil & Gas Inspector

2 Public Square
Wilkes-Barre, PA 18711-0790

570-826-2320
Telephone

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APR 29 2010
OIL & GAS

5500-PM-OG0001 Rev. 10/2009

pennsylvania DEPARTMENT OF ENVIRONMENTAL PROTECTION

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL & GAS MANAGEMENT PROGRAM

DEP USE ONLY	
AUTH #	CNC
Check # 063245	Amount $ 1500.00

#1250
+ 250
#1500

PERMIT APPLICATION FOR DRILLING OR ALTERING A WELL

DEP USE ONLY			
Notes: Vertical Test Well	OGO # 67425	Objection Date - Do not issue before: 4/5/10	Well Permit # 127-20013
	Bond # 12382		Special Cond. A B C D E F
	C: 3/11/10 DA G: 4/5/10 ACI	Date Approved: 4/20/10 JS	Watershed Name: Shehawken Rattlesnake Creek
	INV: 4-22-10		Designation: HQ EV

Please read instructions before you begin filling in this form.

Applicant (Operator) Name	DEP Client ID#	Phone	FAX	Check if new address. ☐
Newfield Appalachia PA LLC	277879	281-847-6031	281-847-6160	
Mailing Address (Street or PO Box): 363 N. Sam Houston Pkwy E. Suite 2020	City: Houston	State: TX	Zip +4: 77060-2424	Country (if not USA)

(Well) Farm Name	Well #	Serial #
D.L. Teeple	1-1	
County: WAYNE	Municipality: MANCHESTER	Project # (from DEP)

If you are applying for a permit to redrill, drill deeper, or alter a well that was previously permitted or registered, ***or for a well site that was previously permitted but not drilled,*** check this box ☐ and enter the permit or registration number here:

If applying for a permit to rework an existing well not registered or permitted, check this box ☐ and enter date drilled, if known:______________ (see instructions)

PNDI Attached: ☒ Any "hit" must include accepted mitigation plan from applicable agency.

PERMIT TYPE
Check applicable.
Application is to:
☒ Drill a new well
☐ Deepen a well
☐ Redrill a well
☐ Alter a well
☐ E&S Control Module
☐ Other (specify)

TYPE OF WELL
Check one.
☐ Gas
☐ Oil
☐ Comb. (gas & oil)
☐ Injection, recovery
☐ Injection, disposal
☐ Coalbed Methane
☐ Gas Storage
☒ Other (specify)
vertical test well

APPLICATION FEE
Check applicable.
☐ Marcellus Well: Non-Vertical
☐ Marcellus Well: Vertical
☐ Non-Marcellus Well: Non-Vertical
☒ Non-Marcellus Well: Vertical
☐ $200 (Home Use Well)
☐ $500 E&S Fee
☐ $ 0 (Rehab orphan)
☒ Vertical: Length 8350 ft.
☐ Marcellus: Length ______ ft.
☐ Non-Vertical: Length ______ ft.
Total Application Fee $ 1500

COORDINATION WITH REGULATIONS AND OTHER PERMITS	Yes	No
1. Will the well be subject to the **Oil and Gas Conservation Law**? If "No," go to 2).	☒	☐
a. If "Yes" to #1, is the well at least 330 feet from outside lease or unit boundary?	☒	☐
b. Does the location fall within an area covered by a spacing order?	☐	☒
2. Will the well penetrate a **workable coal seam**? If "No," include justification and supporting documentation.	☐	☒
3. If the well will penetrate a **workable coal seam**, and the well is a "non-conservation" gas well, does the location comply with the distance requirements of Section 7 of the Coal and Gas Resource Coordination Act? (At least 1,000 feet from all existing wells).	☐	☐
a. If "No," is the required exception request attached? (Check here if re-working an existing well: ☐ N/A)	☐	☐
4. Will the well be drilled at a location where the coal has been removed?	☐	☒
5. Will the well be drilled through an **active (operating or projected) coalmine**, or within 1,000 feet of the boundary?	☐	☒
a. If "Yes," print the names of: Mine: Operator:		
6. Will the well penetrate or be within 2,000 feet of an active **gas storage reservoir boundary**?	☐	☒
a. If Yes, print the names of: Storage Field: Operator:		
7. Is the proposed well location within the permitted area of a **landfill**?	☐	☒
8. Will the well site be within 100 feet (measured horizontally) of a **stream, spring or body of water** identified on the most current 7½' topographic map?	☐	☒
a. If "Yes," is a request for a waiver (form 5500-FM-OG0057), and E&S control plan attached?	☐	☐
9. Will the well site be within 100 feet of a **wetland** or in e **wetland**?	☐	☒
a. Is the well site within 100 feet of a wetland greater than one acre in size?	☐	☐
If yes, is a waiver request (form 5500-FM-OG0057) and E&S control plan attached?	☐	☐
10. Will the well be drilled within 200 feet (horizontally) from any existing **building** or an existing **water supply**?	☐	☒
a. If "Yes," is written consent from the owner attached?	☐	☐
b. If written consent is not attached, is a variance request (form 5500-FM-OG0058) attached?	☐	☐
11. Will the well be located where it may impact a public resource as outlined in the "**Coordination of a Well Location with Public Resources**" form 5500-PM-OG0076? If yes, attach a competed copy of the form.	☐	☒
12. Is the well site in a **Special Protection** High Quality (HQ) or Exceptional Value (EV) watershed?	☒	☐
13. Is this well part of a development where you need an **Earth Disturbance Permit** for Oil and Gas Activities disturbing more than 5 acres? If yes, attach a completed Erosion Sediment and Stormwater Control Module or list the number and date of the ESCGP-1 Approval. ______	☐	☒

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NORTHWEST REGIONAL OFFICE

DEP USE ONLY
Date Stamps/Notes
Auth 826657
Site 731937
Clnt 277879
APS 715262
Acct 674710
PF 728625
SF 1010226

Signature of Applicant: The person signing this form attests that they have the authority to submit this application on behalf of the applicant, and that the information, including all related submissions, is true and accurate to the best of their knowledge.

Signature of Person Authorized to Submit Application	(Print or Type)	Name of Signer: DONALD F. SLEETH Title: Drilling Manager	Date 3-5-10
Donald F. Sleeth II			

Application Preparer/Contact: BETSY COLLINS Phone: 412-921-8250

5500-PM-OG0002-DWG Rev. 09/2008

pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Oil and Gas Management Program

WELL LOCATION PLAT

DEP USE ONLY	DEP Application Tracking #	G: ACO 4/19/10
	Permit # 127-20013	C:
	Project #	

Denotes location of well on topo map.

Well is located on topo map 2,034 feet south of latitude 41 ° 50 ' 00 "

True Latitude: NORTH
41 ° 49 ' 39.90 "

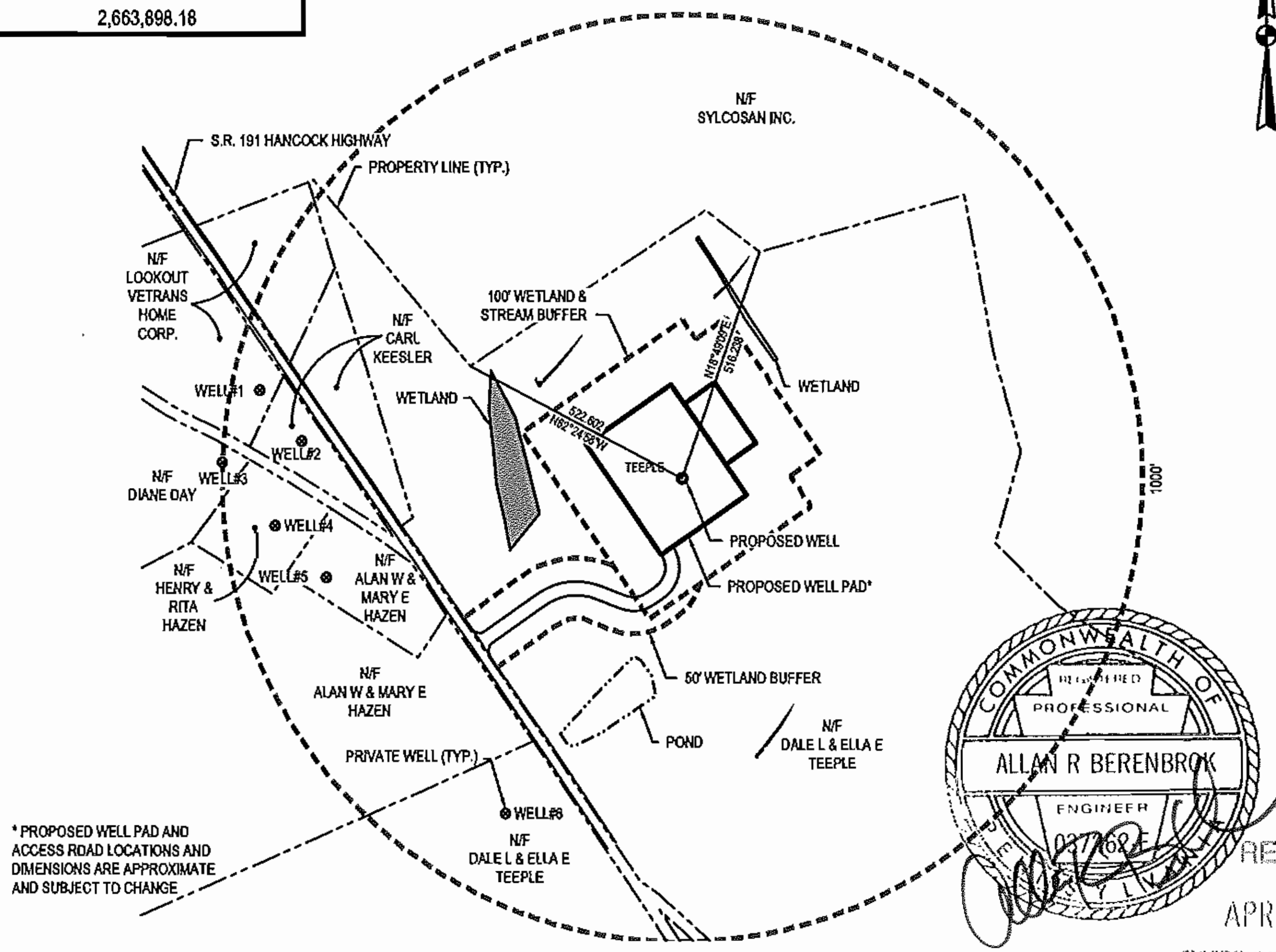
True Longitude: WEST
75 ° 11 ' 53.33 "

WELL NORTHING - Y
615,470.64

WELL EASTING - X
2,663,898.16

HQ Shehawken
WATERSHED Rattlesnake Creek

Well is located on topo map 8,580 feet west of longitude 75 ° 10 ' 00 "



COMMONWEALTH OF PENNSYLVANIA
REGISTERED PROFESSIONAL
ALLAN R BERENBROK
ENGINEER
037762-E

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ENVIRONMENTAL PROTECTION
NORTHWEST REGIONAL OFFICE

Surveyor or Engineer TETRA TECH Phone # (412) 921-8873 Dwg. # 1 Date 4/16/2010 Scale 1" = 400' Tract Acreage

Lat. & Long Metadata		Elevation Metadata		
Method GPS Accuracy +/- 1 ft. Datum NAD83		Method GPS Accuracy +/- 1 ft. Datum NAD83	Survey Date Jan. 2010	
Applicant / Well Operator Name: Newfield Appalachia PA LLC		Well(Farm) Name: D.L. Teeple	Well # 1-1	Serial #
Address: 363 N. Sam Houston Parkway E., Suite 2020, Houston, TX 77060		County - Code: Wayne	Municipality: Manchester	Well Type: Vertical Test
Surface Landowner / Lessor: Dale and Ella Teeple		USGS 71/2 Quadrangle Map Name: Long Eddy, NY 0444	Map Section: 5	Surface Elevation: 1516 ft.
Target Formation(s): Onondaga		Angle & Course of Deviation (Drilling): N/A	Anticipated Total Depth: TVD 8,350 TMD 8,350	

Surface Owner or Water Purveyor with a Water Supply within 1,000 ft.	Approximate Course and Distance to Water Supply	Owner, Lessee, or Operator of Workable Coal Seam	Name of Coal Seam Owned, Leased, or Operated
Lookout Veterans Home Corp.	N78d 20' 44"W 938'	N/A	N/A
Carl Keesler	N84d 27' 43"W 832'	N/A	N/A
Dale L & Ella E Teeple	S27d 51' 49"W 818'	N/A	N/A
Alan W Mary E Hazen	S74d 33' 6"W 802'	N/A	N/A

R:_Marcellus Shale Projects\Newfield\2679 - Newfield Wells\Well Plat Permits\Permit Drawings\Teeple Well Pad Plat Exhibit A.dwg PIT BEN.HOPPE 4/16/2010 12:43:02 PM

NEWFIELD

April 1, 2010

PADEP Oil & Gas Management
230 Chestnut St.
Meadville, PA 16335

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APR 02 2010

ENVIRONMENTAL PROTECTION
NORTHWEST REGIONAL OFFICE

Subject: Newfield Appalachia PA LLC – DEP ID# 277879
D.L. Teeple Well #1-1

To Whom It May Concern:

Please include this letter of clarification as part of our permit application associated with the above captioned well.

This permit is to develop a well which is intended solely for exploratory purposes. A core is to be taken from several formations throughout the drilling process of this well and additional scientific study is to be performed on multiple formations including, but not limited to, geophysical logs, micro-seismic studies and fluid sampling. As permitted and configured, this well is not to be completed for production, not to be hydraulically fractured and is not to produce gas. In the future, this wellbore will either be plugged and abandoned per PADEP regulations, converted to inactive status and utilized as a monitoring well, or reconfigured and converted to a production well. Prior to either plugging and abandonment, conversion to inactive status or reconfiguration and conversion to production, we acknowledge that additional permitting will be necessary with approvals from the PADEP and other regulatory bodies with jurisdiction.

Sincerely,

Donald F. Sleeth
Drilling Manager

5500-FM-OG0001A Rev. 11/2007

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL AND GAS MANAGEMENT PROGRAM

DEP USE ONLY	
Permittee's eFACTS ID 134188	Auth ID 720872
Watershed Name	Quality

WELL PERMIT

Permittee	OGO #	Permit Number	Date Issued
KEVIN E SCHRADER	OGO-66800	37-127-20009-00	03/05/2009

Address PO BOX 262	Farm Name & Well Number B & E WELLS 1 — Well Serial # 01
	Municipality: Preston — County: Wayne
LAKE COMO, PA 18437	7½ ' Quadrangle Name: Lake Como — Map Section #
Phone: (570) 798-0337 — Project #	Latitude: 41-50-38.3 — Longitude: 75-20-18.1
Surf Elev at Site: 1640 feet — Anticipated Total Depth: 8000 feet — Well Type: GS	Offset distances referenced to NE corner of map section. South 11,100 feet West 1,450 feet

This permit covering the well operator and well location shown above is evidence of permission granted to conduct activities in accordance with the Oil and Gas Act and the Oil and Gas Conservation Law, if the well is subject to that act and any rules and regulations promulgated thereunder, subject to the conditions contained herein and in accordance with the application submitted for this permit. This permit does not convey any property rights.

This permit and the permittee's authority to conduct the activities authorized by this permit are conditioned upon operator's compliance with applicable law and regulations.

Notification must be given to the district oil and gas inspector, the surface landowner and political subdivision of the date well drilling will begin at least 24 hours prior to commencement of drilling activities.

The permittee hereby authorizes and consents to allow, without delay, employees or agents of the Department to have access to and to inspect all areas upon presentation of appropriate credentials, without advance notice or a search warrant. This includes any property, facility, operation or activity governed by the Oil and Gas Act, the Oil and Gas Conservation Law, the Coal and Gas Resource Coordination Act and other statutes applicable to oil and gas activities administered by the Department. The authorization and consent shall include consent to the Department to collect samples of wastewaters or gases, to take photographs, to perform measurements, surveys, and other tests, to inspect any monitoring equipment, to inspect the methods of operation and disposal, and to inspect and copy documents required by the Department to be maintained. The authorization and consent includes consent to the Department to examine books, papers, and records pertinent to any matter under investigation pursuant to the Oil and Gas Act or pertinent to a determination of whether the operator is in compliance with the above referenced statutes. This condition in no way limits any other powers granted to the Department under the Oil and Gas Act and other statutes, rules and regulations applicable to these activities as administered by the Department.

This permit does not relieve the operator from the obligation to comply with the Clean Streams Law and all statutes, rules and regulations administered by the Department.

Special Permit Conditions:

The permittee shall not drill the well until the permittee submits to the Department and the Department has approved the method by which the permittee will withdraw, use, store, distribute, process and dispose of water for well drilling and hydraulic fracturing purposes. ("Water Management Plan").

This permit expires 03/05/2010 unless drilling is commenced on or before that date and prosecuted with due diligence.

S. Craig Lobins

Regional Oil and Gas Program Manager

HERB KARLINSEY Oil and Gas Inspector	P O Box 673, Coudersport, PA 16915-0673 Address	814-274-3611 Telephone

5500-PM-OG0002 Rev. 6/2008

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL AND GAS MANAGEMENT PROGRAM

WELL LOCATION PLAT

DEP USE ONLY	
Auth ID #:	
Permit #:	127-20009
Project #:	

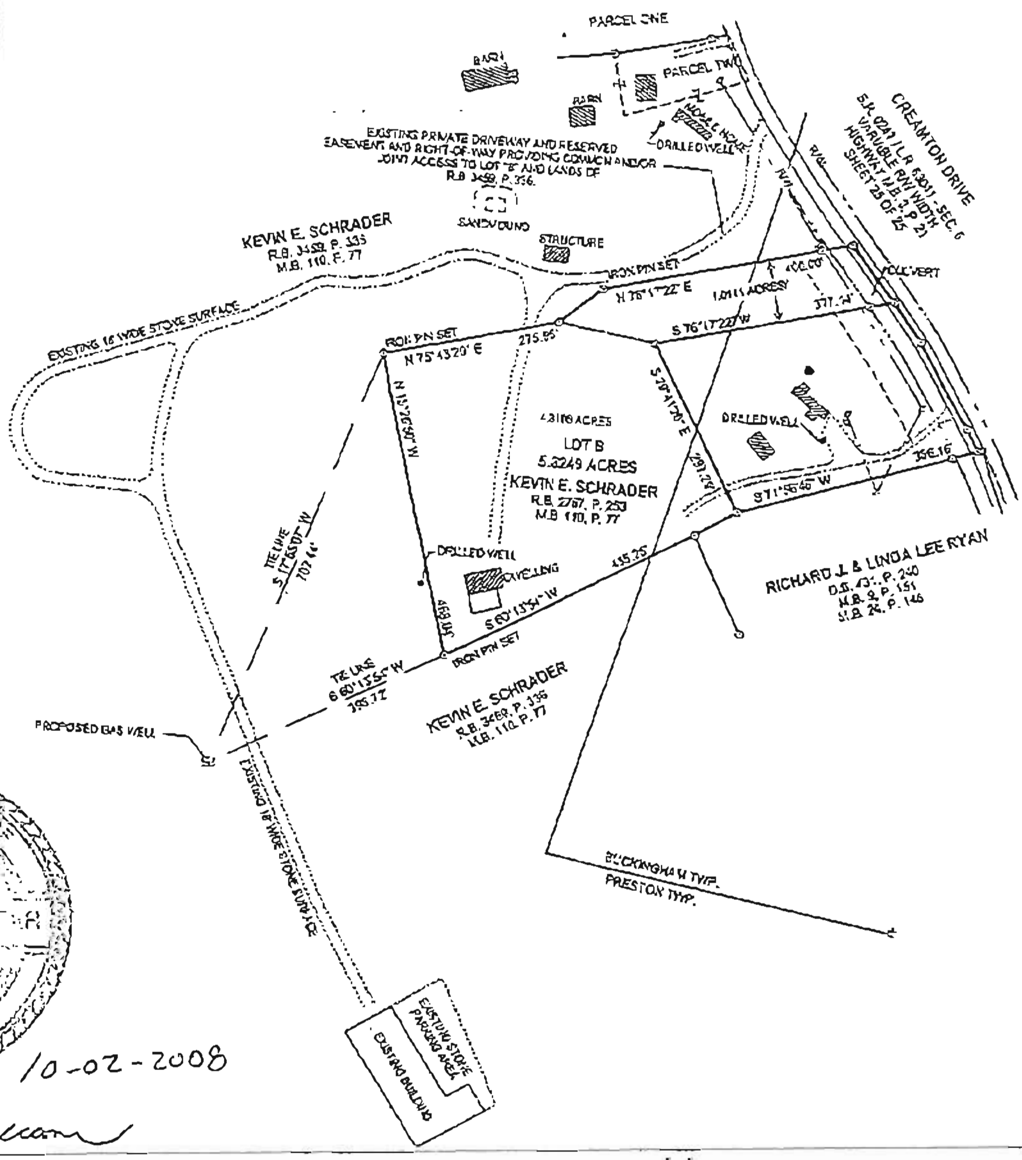
Denotes location of well on topo map.

True Latitude: NORTH
41 ° 50 ' 38.3 "

True Longitude: WEST
75 ° 20 ' 18.1 "

Well is located on topo map 1100 feet south of latitude 41 ° 52 ' 30 "

Well is located on topo map 1450 feet west of longitude 75 ° 20 ' 00 "



COMMONWEALTH OF PENNSYLVANIA
REGISTERED
PROFESSIONAL
ALFRED K. BUCCONEAR
LAND
SURVEYOR
PENNSYLVANIA

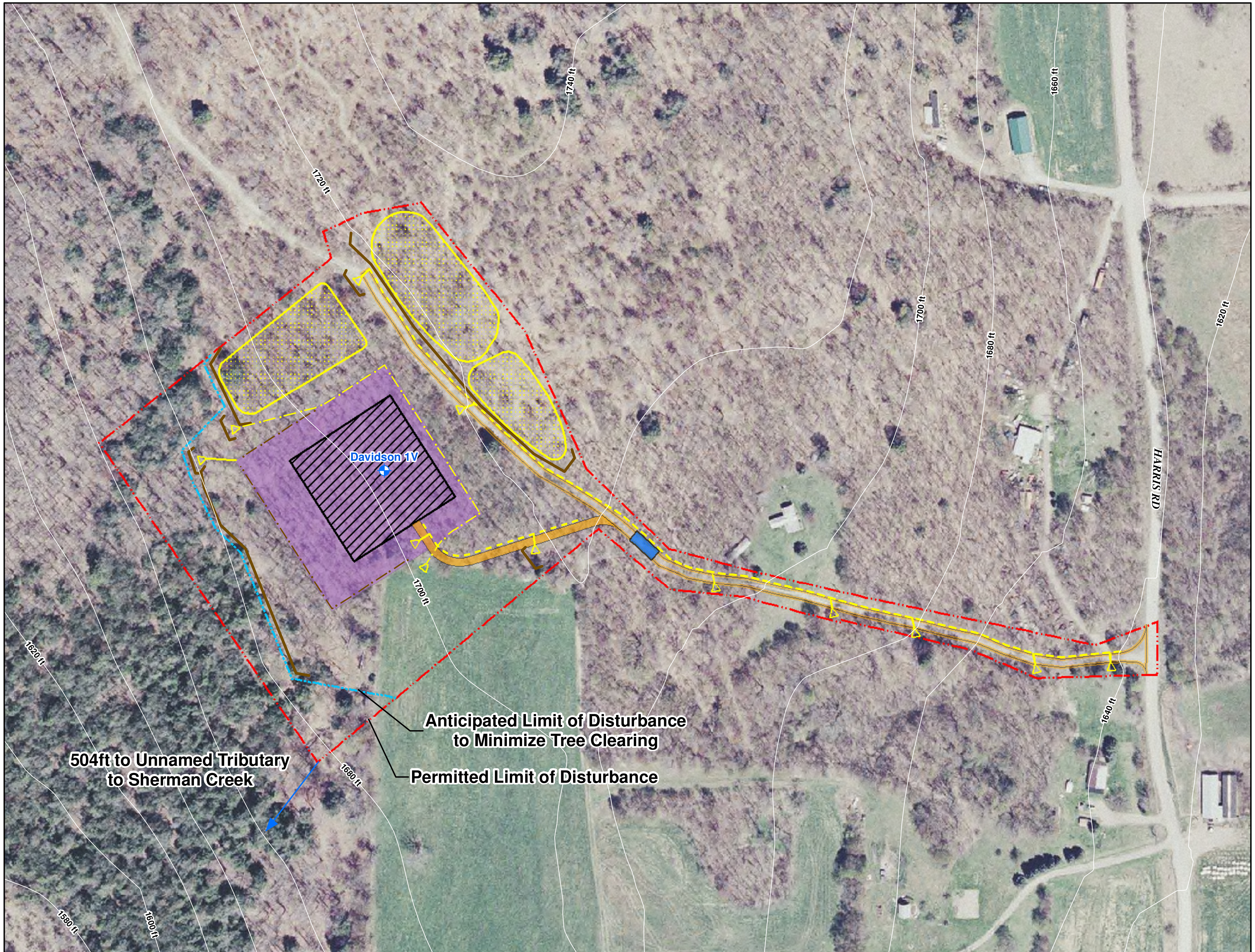
10-02-2008

Alfred K. Bucconear

REVISED 10/2/08

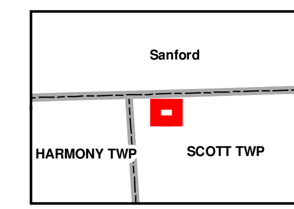
Surveyor or Engineer: ALFRED K. BUCCONEAR	Phone #: (570) 488-6847	Dwg #:	Date: 7/25/08
Scale: 1" = 300'	Tract Acreage: 177.28±		
Lat & Long Metadata Method: HANDHELD GPS	Accuracy: 13'± ft. Datum		
Elevation Metadata Method: HANDHELD GPS	Accuracy: 13'± ft. Datum	Survey Date: 3/19/08	
Applicant / Well Operator Name: KEVIN E. SCHRADER	DEP ID#:	Well (Farm) Name: B & E WELLS	Well #: 1
Serial #:			
Address: 3230 CREAMTON DR. BOX 262 LAKE COMO PA. 18437	County: WAYNE	Municipality: PRESTON	Well Type: GAS
Surface Landowner / Lessor: SAME AS ABOVE	USGS 7½' Quadrangle Map Name: LAKE COMO, PA.-NY	Map Section: SECTION 1	
Target Formation(s): Marcellus Shale formation	Angle & Course of Deviation (Drilling): VERTICAL	Surface Elevation: 1640 ft.	Anticipated Total Depth: 8000 ft.

Surface Owner or Water Purveyor with a Water Supply within 1000 ft.	Approximate Course and Distance to Water Supply	Owner, Lessee, or Operator of Workable Coal Seam	Name of Coal Seam Owned, Leased, or Operated
Kevin Schrader	300'		



Legend

- Vertical Well Location
- Cross Drain Culverts w/ Rip-Rap Apron
- Compost Filter Sock
- Roadside Ditch
- Diversion Ditch
- Containment Berm
- 20ft Contour Interval
- Construction Entrance w/ Tire Wash Rack
- Stockpile Area (Topsoil, Excess Soil & Vegetation)
- Proposed Access Road
- Existing Access Road
- Restored Vertical Well Pad (200'x200')
- Construction Vertical Well Pad (300'x300')
- Anticipated Limit of Disturbance
- Permit Limit of Disturbance



Key Map
Not to Scale

N

NAD 1983 State Plane
Pennsylvania North FIPS 3701
Projection: Lambert Conformal Conic
Linear Unit: Foot US

0 85 170 340 Feet

1 inch = 170 feet

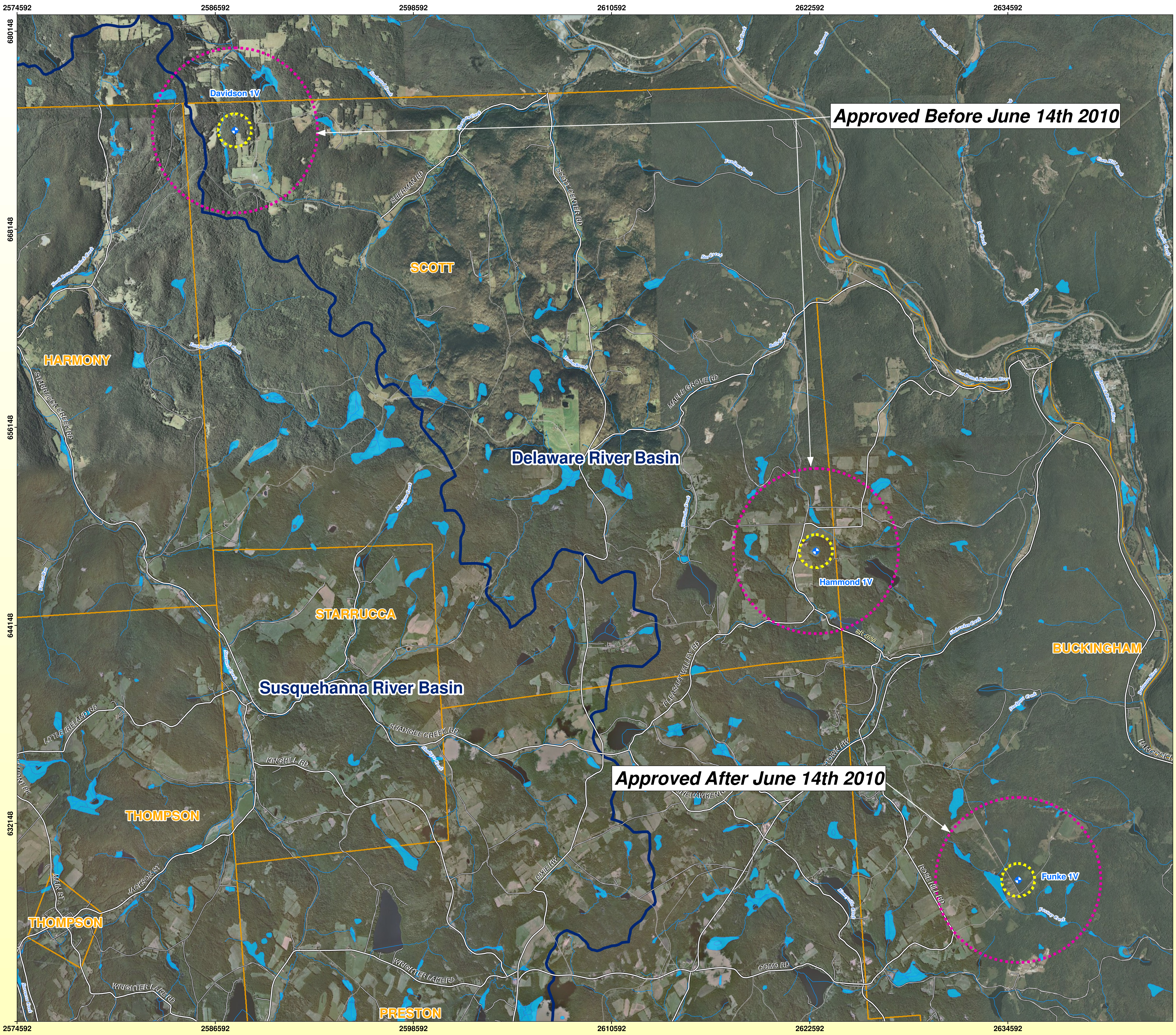
URS

Davidson 1V Well Site
Hess Marcellus Shale Exploration

Wayne County, Pennsylvania

Prepared By: VP	Checked By: RW
Job:19998485.00001	Date: 07/12/2010

Q:\GIS_Data\HESS\MARCELLUS\Projects\DRBCPresentation2010July\Davidson-1V.mxd



Hess Corporation Marcellus Shale Exploration Regional Extent

Legend

- Vertical Well Location
- 1000' Radius PADEP Limit of Liability
- Baseline Water Sample 5000' Radius
- PA Unpaved Roads
- PA Local Roads
- PA State Roads
- Rivers and Streams
- Susquehanna and Delaware River Basins Boundary
- National Wetlands Inventory
- Municipal Boundaries

URS Corporation
July 2010

Source:
2006 1M Natural Color NAIP
PA State Municipal Boundaries
DRBC Watershed Boundaries
Parcel Data from Wayne County Municipalities

NAD 1983 StatePlane Pennsylvania North
FIPS 3701 U.S. Feet
Projection: Lambert Conformal Conic
False Easting: 1968500.000000
False Northing: 0.000000
Central Meridian: -77.750000
Latitude Of Origin: 40.166667

GCS North American 1983

N

0 2,000 4,000 8,000 Feet

1 inch = 2,000 feet (when printed as ANSI E-Size)

URS

5500-PM-OG0002-DXF Rev. 11/2003

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Oil and Gas Management Program
WELL LOCATION PLAT

DEP USE ONLY	DEP Application Tracking # OGS #636450	# 3/11/08
	Permit # 127-20006	C:
	Project #	

Denotes location of well on topo map.

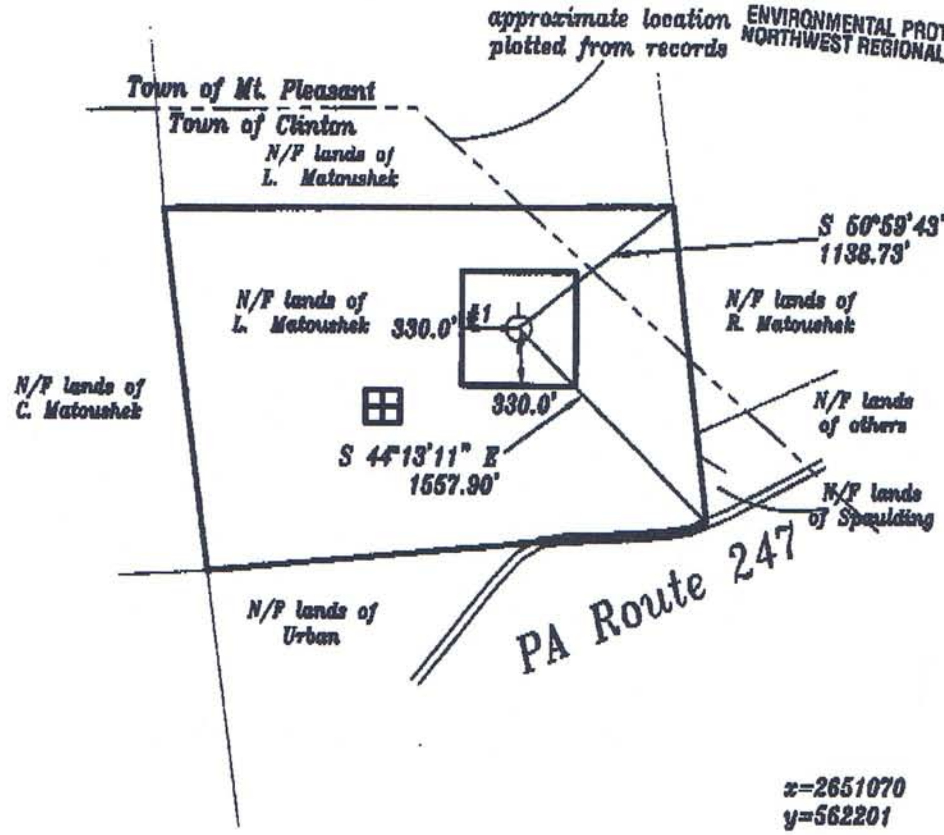
True Latitude: NORTH
41° 41' 06.39"

True Longitude: WEST
75° 21' 58.21"

Well is located on topo map 8436 feet south of latitude 41 ° 42 ' 30 "

Well is located on topo map 8968 feet west of longitude 75 ° 20 ' 00 "

RECEIVED
MAR 06 2008
ENVIRONMENTAL PROTECTION
NORTHWEST REGIONAL OFFICE



NORTH

D. Michael Canada

Surveyor or Engineer D. Michael Canada Pa. Lic. # 029272 E	Phone # (716) 379-7816	Dwg. # 6669	Date Rev. 3/3/08 December 12, 2007	Scale 1" = 1000'	Tract Acreage 133.45 AC

Lat. & Long Metadata Method Static GPS Accuracy ± 10 ft. Datum NAD 27	Elevation Metadata Method Scaled Accuracy ± 10 ft. Datum USGS Quad; Survey Date Dec. 11, 2007
Applicant / Well Operator Name: Stone Energy Corporation	Well(Farm) Name: Matoushek; Well # # 1; Serial #
Address: PO Box 5280 Lafayette, LA. 70506	County - Code: Wayne; Municipality: Clinton / Mt. Pleasant
Surface Landowner: Louis Matoushek	USGS 7 1/2 Quadrangle Map Name: Alderville; Map Section 4
Surface Lessor	Angle & Course of Deviation (Drilling); Surface Elevation 1545 ft.; Anticipated Total Depth 8150' ft.

Surface Owner or Water Purveyor with a Water Supply within 1,000 ft.	Approximate Course and Distance to Water Supply	Owner, Lessee, or Operator of Workable Coal Seam	Name of Coal Seam Owned, Leased, or Operated

DEP

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Oil and Gas Management Program

WELL LOCATION PLAT

AC

DEP Application Tracking #	2OSH 639350	4/30 4-18-08
Permit #	127-20007	c.
Project #		

Denotes location of well on topo map.

Well is located on topo map 8703 feet south of latitude 41 ° 42 ' 30 "

True Latitude: NORTH
41° 41' 03.74"

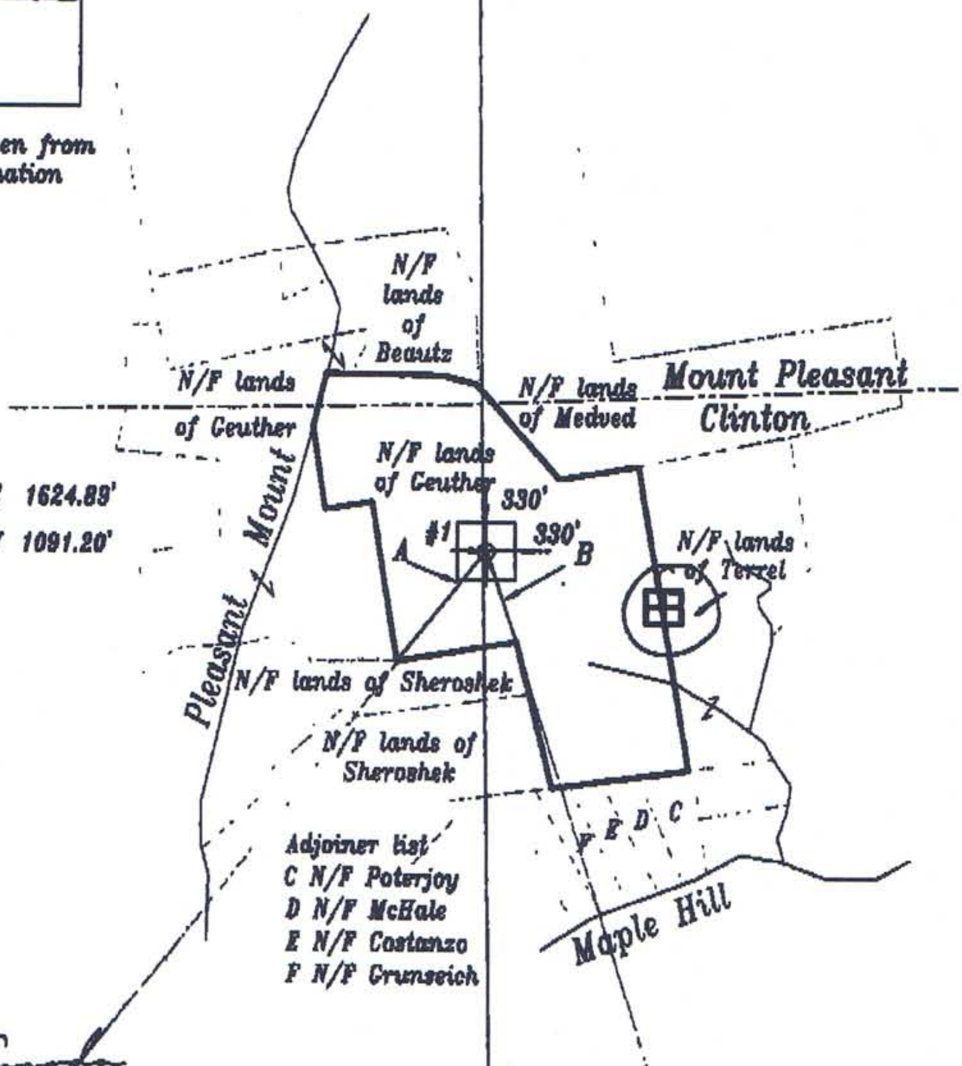
True Longitude: WEST
75° 26' 10.86"

Well is located on topo map 5377 feet west of longitude 75 ° 25 ' 00"

parcel lines taken from tax map information

x 561411.86
y 2631916

A N 38°52'59" E 1624.89'
B N 17°59'20" W 1091.20'



D. Michael Caranda

Surveyor or Engineer D. Michael Caranda Pa. Lic. # 029272 E	Phone # (716) 379-7918	Dwg. # 6669	Date Rev. Mar. 3, 2008 January 30, 2008	Scale 1" = 2000'	Tract Acreage 261

Lat. & Long Metadata Method Static GPS Accuracy ± 10 ft. Datum NAD 27	Elevation Metadata Method Scaled Accuracy ± 10 ft. Datum USGS Quad Survey Date 1/30/2008
Applicant / Well Operator Name Stone Energy Corporation	Well (Farm) Name Geuther Well # 41 Serial #
Address PO Box 5280 Lafayette, LA 70506	County - Code Wayne Municipality Clinton
Surface Landowner Robert Geuther	USGS 7 1/2 Quadrangle Map Name Forest City Map Section 5
Surface Lessor	Angle & Course of Deviation (Drilling) Vertical 0 Surface Elevation 2210 ft. Anticipated Total Depth 8150 ft.

RECEIVED

APR 17 2008

ENVIRONMENTAL PROTECTION

DOCKET NO. D-2009-13-1

DELAWARE RIVER BASIN COMMISSION

Special Protection Waters

Stone Energy Corporation
Surface Water Withdrawal for Natural Gas Exploration and Development Projects
West Branch Lackawaxen River Withdrawal Site
Mount Pleasant Township, Wayne County, Pennsylvania

PROCEEDINGS

This docket is issued in response to an Application submitted to the Delaware River Basin Commission (DRBC or Commission) by Stone Energy Corporation (Stone) on March 5, 2009 for review of a surface water withdrawal from the West Branch of the Lackawaxen River (WBLR). The withdrawal will be used to support Stone's natural gas development and extraction activities targeting shale formations within the drainage area of Special Protection Waters within the Delaware River Basin (DRB) in the Commonwealth of Pennsylvania.

The Application was reviewed for approval under Section 3.8 of the *Delaware River Basin Compact*. The Wayne County Planning Commission and the Township of Mount Pleasant, Wayne County, Pennsylvania has been notified of pending action on this docket. A public hearing on this project was held by the DRBC on February 24, 2010.

A. DESCRIPTION

1. Purpose. The purpose of this project is to withdraw up to 0.7 million gallons per day (mgd) of surface water from the WBLR to support Stone's natural gas development and extraction activities targeting shale formations within the drainage area of Special Protection Waters within the DRB in the Commonwealth of Pennsylvania.

2. Location. The Stone surface water withdrawal (WBLR withdrawal site) is located on private property under lease agreement with Stone in Mount Pleasant Township, Wayne County, Pennsylvania. The withdrawal point is located in the WBLR watershed. The WBLR is classified by Pennsylvania Department of Environmental Protection (PADEP) as a high quality (HQ)-Cold Water Fishery (CWF) stream. Specific latitude and longitude location information of the withdrawal point has been withheld for security reasons.

3. Area/Wells Served. The surface water withdrawals from the WBLR withdrawal site shall only be used to support Stone's natural gas development and extraction activities targeting shale formations within the drainage area of Special Protection Waters within the DRB in the

Commonwealth of Pennsylvania. For the purpose of this docket, natural gas development and extraction activities include or are associated with: mud rotary/air rotary natural gas well drilling, hydraulic fracturing well stimulation, mixing cement for well construction, mixing drilling mud/fluid, support vehicle tire cleaning, dust control and site construction and reclamation on associated well pad sites and access roads within Stone's lease holdings in the Pennsylvania portion of the DRB. Subject to the limitations in this docket, the surface water withdrawals under this docket shall only to be used to support Stone's natural gas development and extraction activities at sites targeting shale formations within the drainage area of Special Protection Waters within the DRB in the Commonwealth of Pennsylvania that have the applicable approvals by the DRBC and the Pennsylvania Department of Environmental Protection (PADEP) (See discussion in Findings section and Conditions in the Decision section of the docket). For the purpose of defining Area Served, the Application is also incorporated herein by reference consistent with conditions contained in the Decision section of this docket and without expanding the limitations or service area as set forth above.

4. **Physical Features.** The docket holder estimates that the majority of the withdrawn surface water will be used to stimulate horizontal and/or vertical natural gas wells by hydraulic fracturing. The remaining withdrawn water will be used for mixing cement for well construction, mixing drilling mud/fluid, support vehicle tire cleaning, dust control and site construction and reclamation on associated well pad sites and access roads within Stone's lease holdings in the Pennsylvania portion of the DRB.

a. **Surface Water Source Design Criteria.** Proposed facilities at the WBLR withdrawal site will consist of up to eight 6-inch diameter floating intake screens (Megator Dolphin Floating Suction Strainers) on the end of flexible suction line attached to a portable Prime Series pump. The floating suction strainers shall be tethered to the stream bank using nylon rope or steel cable. The pump will have an intake capacity of 1,040 gallon per minute (gpm) (see Condition n in the Decision section of the docket). A duplicate back-up pump unit may also be stored at the site. Water withdrawn from the WBLR will be distributed directly into a maximum of ten (10), 500-barrel capacity (21,000 gallon) mobile storage tanks located within a fenced-in and gated staging area approximately 0.5 acres in size. Water will be pumped from the storage tanks into the tanks of the water trucks via pumps carried on the hauling vehicles. The water trucks will be filled within the staging area. The pumps will also be located within the fenced in staging area. The staging area shall be constructed with coarse stone aggregate underlain where necessary by a geosynthetic liner. The withdrawal location will have restricted access, through use of fencing and signage. The withdrawal location will be restricted to the operations associated with the function of water withdrawal. Prior to construction, the docket holder will submit final plans and specifications for the WBLR withdrawal site to the Commission. No construction shall commence at the WBLR site until the final plans and specifications have been submitted to the Commission and approval by the Executive Director in accordance with Condition e. in the Decision section of the docket

The withdrawn water and equipment in contact with that water shall be managed and treated in accordance with the Invasive Species Control Plan (if determined to be applicable) and the Operation Plan (Conditions r and s respectively in the Decision section of the docket) to prevent the spread of invasive species.

The water storage tanks located on site shall only be used to store and distribute surface water from the WBLR. The docket holder will meter, record, and report the volume of surface water withdrawn from the WBLR as it is distributed to the storage tanks as described in Section B. FINDINGS, below and in the Decision section of the docket. Records of the volume of water distributed from the storage tanks to the hauling vehicles will be maintained and reported as part of the required transportation records as described in Section B. FINDINGS, below and in the Decision section of the docket.

Portions of the project site are located in the 100 year flood plain as delineated on the Federal Emergency Management Agency maps. Facilities at the WBLR site shall be designed and constructed in accordance with Commission Flood Plan Regulations (FPR) (e.g. lowest operating floor of such facility is above the Flood Protection Elevation (as defined in the FPR), or the facility is flood proofed according to plans approved by the Commission nor unless emergency plans and procedures for action to be taken in the event of flooding are prepared). (See Condition d. in the Decision section.)

The water system on this site will not be interconnected with any public or private water supply system and withdrawn water will only be used for the purposes defined in Section A.3 Area/Wells Served.

b. **Cost.** The overall cost of this project is estimated to be $18,700. This cost includes planning design, and construction of the surface water withdrawal intake, staging area, and associated appurtenances.

B. FINDINGS

This docket was prepared by Commission staff in response to an Application submitted to the Delaware River Basin Commission (DRBC or Commission) by Stone on March 5, 2009 for review of a surface water withdrawal from the WBLR to be used to support Stone’s natural gas development and extraction activities targeting shale formations within the drainage area of Special Protection Waters within the DRB in the Commonwealth of Pennsylvania.

The Commission provided public notice in regards to this docket application in the Federal Register on February 19, 2010. The Commission also notified parties on the Interested Parties List for this application and posted the draft Stone WBLR Withdrawal Site docket on the Commission website on February 9, 2010. On February 24, 2010, a public hearing was held at the Best Western Inn in Matamoras, Pennsylvania. Due to public interest in the project, the comment period was extended from March 12, 2010 until April 12, 2010. During the hearing, which lasted over 7 hours, oral and written comments were received. Including the comments and written materials submitted at the February 24, 2009 hearing and during the extended public comment period, the Commission received over 2,000 letters, emails, and supporting materials during the public comment period. A copy of the transcript of the February 24, 2010 hearing and a list of the commenters that submitted comments during the hearing is available from the Commission.

Comments were received from the public, local governments, various organizations, federal and state agencies industry representatives, and the project sponsor. A significant number of comments were received from the public and other sources. While the majority of comments were in opposition to the Commission proceeding with the approval of the docket, there were also comments in favor of the proposed Commission action. Federal and state agency comments were more specifically related to docket and site requirements.

On May 5, 2010, the Commissioners directed Commission staff to draft regulations for natural gas well pad projects in shale formations in the Delaware River Basin. The Commissioner's also indicated that it will consider specific natural gas well pad applications after the new regulations are in place. The Commissioners also indicated that applications for water withdrawals associated with natural gas well pad applications activities targeting shale formations within the drainage area of Special Protection Waters within the Delaware River Basin (DRB) should continue to be processed since such applications are similar to water withdrawal applications for other uses in the DRB.

Commission staff's review of Stone's Matoushek 1 natural gas well pad application is suspended. Comments that were received during the public hearing and comment period concerning Stone's Matoushek 1 natural gas well pad docket are not addressed in the attached document. Stone's WBLR application indicated that the water withdrawal would be used for Stone's natural gas well pad activities targeting shale formations in Pennsylvania within the drainage area of Special Protection Waters within DRB. In addition, Stone indicated that it wants the processing of the WBLR application to be completed, despite the suspension of the processing of natural gas well pad applications.

After review of the comments and testimony received in preparation for the July 14, 2010 Commission meeting, Commission staff provided the Commissioners with:

- DRBC staff memo dated July 2, 2010 recommending that the Commissioners approve the attached Stone Energy docket No. D -2009-013-1 at the July 14, 2010 Commission meeting.
- DRBC staff response document to the major issues/comments received during the public comment period and public hearing concerning the Stone Energy Corporation draft Docket No. D-2009-0013- 1.
- A revised draft docket.

The Commission staff does not consider these revisions substantial and therefore does not recommend re-noticing of the draft docket or reopening the public comment period. The notice announcing that the Commission will consider this docket at the Commission's July 14, 2010 meeting was published in the Federal Register on June 29, 2010. Commission staff sent notices to the parties on the Interested Parties List on June 30, 2010.

Public comments were not requested at the July 14, 2010 Commission meeting since: an individual public hearing was held on the draft docket; the public comment period closed on April 12, 2010; and, no substantial changes have been made to the draft docket. During the July 14, 2010 business meeting, the Commissioners' approved the docket for the project withdrawal.

This docket restricts the sites to which the water withdrawn from the WBLR withdrawal site may be transported to and used at (the receiving sites), but does not address the limitations needed to conform activities at these receiving sites to the Commission's Comprehensive Plan. This docket does not approve nor should it imply the Commission determinations of the natural gas development and extraction receiving sites or the activities conducted at those sites. The Delaware River Basin Commission (DRBC) at its May 5, 2010 public business meeting directed commission staff to draft regulations for natural gas well pad projects in shale formations in the Delaware River Basin. The Commissioners will consider specific natural gas well pad applications after the new regulations are in place. The Commissioners also indicated that the review of pending or future proposed water withdrawals to be used to supply water to natural gas extraction projects, including Stone Energy's proposed water withdrawal from the West Branch Lackawaxen River in Mount Pleasant Township, Wayne County, Pa., will proceed in accordance with existing DRBC regulations. In proceeding with the project under this docket, the docket holder is proceeding at its own risk relative to the Commission determinations yet to be made at such receiving sites.

In the review of this Application, Commission staff has also considered the following on and off-site natural gas development and extraction site activities:

a. **Off-site Natural Gas Development and Extraction Activities.** The recommendation to approve the water allocation under this docket is based on the docket holder's projected water demand to support Stone's natural gas development and extraction activities within the DRB in the Commonwealth of Pennsylvania. Condition k. in the Decision section of this docket requires that surface water withdrawals from the Stone WBLR Withdrawal Site shall only be used to support Stone's natural gas development and extraction activities in the drainage area to Special Protection Waters in the Pennsylvania portion of the DRB for natural gas wells targeting shale formations. The condition also requires that such sites must have been approved by the Commission and also the PADEP. Condition m. in the Decision section provides that no water withdrawal from the WBLR shall commence until the docket holder has received approval of the Commission and PADEP for natural gas development and extraction activities targeting shale formations within the drainage area of Special Protection Waters within the Delaware River Basin (DRB) in the Commonwealth of Pennsylvania.

Off-site Non-Point Source Pollution Control Plans. In the case of off-site natural gas well development and extraction activities targeting shale formations, a separate NPSPCP will be a requirement within a Commission approval for those sites

Off-site Wastewater Generation and Disposal. The Commission's review of all water withdrawal requests includes an evaluation of the wastewaters generated from the approved withdrawals to ensure that the wastewater will be adequately treated and disposed. No water that is withdrawn from the WBLR withdrawal site (see Condition q. in the Decision section of this docket) may be discharged within the DRB, except as provided for in this docket or in accordance with future Commission issued natural gas development and extraction site approvals. Stone must demonstrate that all water withdrawn from the WBLR withdrawal site that becomes wastewater as a result of natural gas development and extraction site activities (e.g. domestic or hydro-fracturing flow-back water and produced water from gas well drilling that cannot be used in the well stimulation process) shall be conveyed to treatment and disposal facilities approved by the DRBC (if in the DRB and subject to Commission approval) as well as by the applicable state/Federal agency (if inside or outside of the DRB). The docket holder is encouraged to use the flow-back water for well stimulation in accordance with Condition w in the Decision section.

To date, the Commission has not approved any in-basin disposal facilities to accept non-domestic related wastewater from natural gas development and extraction activities. In support of its application, the docket holder indicated that it currently intends to transport the wastewaters generated from this water withdrawal to approved treatment facilities outside the DRB. The docket holder has provided the Commission with the names and addresses of these facilities. This list is available for review upon written request or at the Commission's office. Commission staff is satisfied that plans exist for treatment of wastewaters generated as a result of this withdrawal approval. The determination that any of these facilities or alternative facilities can accept the volume and quality of the wastewaters from natural gas development and extraction site activities will also be reviewed when natural gas well site specific applications are submitted to the Commission. Specific conditions for wastewater disposal will be included in any docket that may be issued for natural gas well site development and extraction activities.

On-site Findings

Special Protection Waters

The project is located in the area of the Delaware River Basin that is designated by the Commission as Special Protection Waters as set forth in the DRBC *Water Quality Regulations* (WQR). The SPW designation and associated regulations are designed to protect waters with exceptional value including without limitations existing high water quality in applicable areas of the Delaware River Basin. Article 3.10.3A.2.e.1). and 2). of the *WQR, Administrative Manual* -

Part III, requires that projects subject to review under Section 3.8 of the Compact that are located in the drainage area of Special Protection Waters must submit for approval a Non-Point Source Pollution Control Plan (NPSPCP) that controls the new or increased non-point source loads generated within the portion of the docket holder's service area which is also located within the drainage area of Special Protection Waters. One exception to the NPSPCP requirement is for projects that are located above major surface water impoundments listed in Section 10.3.A.2.g.5) where time of travel and relevant hydraulic and limnological factors preclude a direct impact on Special Protection Waters (Section 10.3.A.2.e.1. c)

The docket holder's surface water withdrawal point is located within the drainage area to Special Protection Waters. The NPSPCP plan requirement is applicable to this project. This project includes the construction of a surface water intake, staging area, and associated appurtenances. The docket holder submitted a general NPSPCP with the Application. However, no site construction activities or water withdrawals approved by this docket shall take place at the WBLR withdrawal site until a site specific NPSPCP including measures to control stormwater both during and post construction on the site has been submitted to the Commission and approved by the Executive Director (Condition i. and any other necessary federal, state, and local authorizations have been issued.

Withdrawal Site and Operations

The intake proposed at the WBLR withdrawal site shall be constructed in accordance with a design approved by PAF&BC, USACE and U.S. Fish & Wildlife Service that in the agencies' view minimizes to the greatest extent possible, impingement and entrainment impacts in the vicinity of the withdrawal site (Condition p. in the Decision section of the docket).

Surface water withdrawal is restricted to the intake structure to be located in the WBLR as provided for in this docket and as described in the Application and supporting materials. All surface water shall be conveyed directly to the water storage tanks and then to the hauling vehicles. Surface water withdrawals from the WBLR withdrawal site shall be metered through a metering plan designed to meet the DRBC metering, recording and reporting requirements of the Commission's Water Code, this docket, and the docket holder's approved Operations Plan described below. The volume of water withdrawn from the WBLR withdrawal site shall be metered and recorded by means of an automatic continuous recording device, or flow meter, and shall be measured to within 5% of actual flow (Condition t. in the Decision section of the docket). The docket holder shall report average daily withdrawal rate and daily and monthly totals of the withdrawal to the Commission on a monthly basis beginning with the 5th calendar day of the month following the month in which the water withdrawals commence in accordance with Condition t. in the Decision section of the docket. Any withdrawals that exceed the allocation provided for in Condition n. of the Decision section of the docket will be reported to the Commission within 48 hours of the exceedance in accordance with Condition ee. of the Decision section of the docket.

A control box located at the withdrawal location, combined with a metering system shall be used to control pump operations. The water storage tanks located on site shall only be used to store and distribute surface water from the WBLR withdrawal site. The docket holder shall meter, record, and report the volume of surface water withdrawn from the WBLR withdrawal site before it is distributed to the storage tanks as described in Section B. FINDINGS, below and in the Decision section of the docket.

The amount of water withdrawn from the WBLR withdrawal site shall be automatically metered and recorded daily and shall be available for inspection. The proposed WBLR surface water withdrawal pump controls shall restrict the surface water withdrawal rate to an instantaneous flow not to exceed 1,040 gpm or a total of 0.7 million gallons (MG) during any day from the river whichever is less. A "day" is defined as the 24-hour period between 12:00 AM and 12:00 AM the following day. At any time during the day, when the total volume withdrawn from the WBLR reaches 0.7 MG, the pump shall automatically shut off, not permitting any additional withdrawals from the source until the start of the following day. A pump operator will be onsite to supervise and monitor all pumping operations.

In addition to the metering and recording above, the docket holder shall maintain water transportation records for all water transferred from the WBLR withdrawal site. There shall be no direct transfer of water from the WBLR withdrawal site to a water hauling vehicle without metering and recording. Records maintained by the docket holder and kept at the WBLR withdrawal site (or at an alternative site approved in writing by the Executive Director) will include the trucking company name, license plate, name of the driver, amount of water transferred, date and time of transfer and destination of the transported water. Surface water withdrawals from the WBLR withdrawal site shall only be used to support Stone's natural gas development and extraction activities targeting shale formations within the drainage area of Special Protection Waters within the DRB in the Commonwealth of Pennsylvania (Condition k. in the Decision section of this docket).

All water withdrawn from the WBLR withdrawal site shall be treated to prevent the spread of potentially invasive, harmful, or nuisance species from entering other watersheds in the DRB as required in the approved Invasive Species Control Plan (ISCP) described in Condition r. in the Decision section of this docket.

Unused surface water from any of the docket holder's Commission approved natural gas development and extraction site activities targeting shale formations in the DRB may be transported to and used at other Commission and state-approved well pads targeting shale formations controlled by the docket holder in the DRB, with the written approval of the Executive Director. Such transfers shall also be reported to the Commission. The Commission encourages the reuse of recovered fracturing fluids (flow back and production fluids), however reuse must be in accordance with the terms and conditions contained in natural gas well pad dockets that may be issued within the DRB. Any reuse shall also be reported to the Commission.

No recovered fracturing fluids shall be used for any purpose other than hydraulic fracturing at natural gas wells targeting shale formations.

No water, fresh or otherwise (e.g. cement mixer wash-out, truck wash water, etc) shall be discharged to waters of the DRB except in accordance with written approvals from the Commission and/or the appropriate state agency (Condition q. in the Decision section of this docket).

The withdrawal location will have restricted access, through use of fencing, signage or other similar means. The WBLR withdrawal site location will be restricted to operations associated with the function of water withdrawal. These areas will not be used as staging areas for chemical additives, except as necessary as part of the ISCP, or fuels above what is likely needed to run an emergency generator if one is used.

Pass-by Flow

The withdrawal shall allow at all times of the year, a minimum flow of water in the WBLR to pass-by as measured below the intake at the WBLR withdrawal site. The WBLR withdrawal site shall be fitted by the docket holder with a gage (the Stone WBLR gage) or another gage or other instrumentation approved by the Executive Director and calibrated to the downstream Aldenville gage station flow data. The installed gage shall be a real-time monitoring and recording gage. For the period of record from 1987 to 2007, the average daily flow statistic calculated for the 40.6 square mile drainage area at the Aldenville gage is 84.1 cubic feet per second (cfs). The proportional average daily flow statistic for the 11.5 square mile drainage area at the Stone WBLR withdrawal site is 23.7 cfs. The pass-by flow, which is based on 25 percent of the average daily flow, shall be a minimum of 5.9 cfs as measured at the Stone WBLR gage. Daily withdrawal rates shall be reduced as appropriate to ensure that a minimum of 5.9 cfs passes by the Stone WBLR gage (Condition o). Withdrawals shall cease entirely if the 24-hour average flow at the Stone WBLR gage, less the withdrawal, is 5.9 cfs or less. The pumps shall be shut off, not permitting any additional withdrawals from the WBLR until the flow as measured at the Stone WBLR gage is at least 8.2 cfs for a 24 hour period. The monitoring and metering of the withdrawal activities at the WBLR withdrawal site shall be described in the Operations Plan. Pass-by flows for the WBLR withdrawal site are summarized in the table below:

STREAM IDENTITY	NEAREST USGS STREAM GAGE	25% OF AVERAGE DAILY FLOW AT ALDENVILLE GAGE (DATA YEARS 1987-2007)	INTAKE PUMP CAPACITY	MINIMUM PASS-BY FLOW REQUIRED AT WITHDRAWAL SITE
West Branch Lackawaxen River Intake	Aldenville Gage #1428750	21 cfs	1,040 gpm	5.9 cfs

The pass-by flow is established from readily available data from the Aldenville gage station operated by the United States Geologic Survey (USGS). The gauge is located approximately 4.0-miles downstream of the proposed WBLR withdrawal site location.

The Stone WBLR gage shall be periodically calibrated by the docket holder. The calibration schedule will be based on the same frequency used by the USGS to re-calibrate its gage station. The Operations Plan shall establish the calibration schedule. The data from the Stone WBLR gage will be converted to daily average flow data for reporting and pass-by flow compliance monitoring. The docket holder shall compare the Stone WBLR gage and the USGS Aldenville gage station no less than once per week through direct observation and real time flow measurements provided by the USGS website when the flow measured at the Stone WBLR gage is 10 cfs or more. When the 24 hour average flow at the Stone WBLR gage is less than 10 cfs the docket holder shall compare the USGS Aldenville gage station and the Stone WBLR gage no less than once per day to ensure compliance with the 5.9 cfs pass-by flow. The Stone WBLR gage must be checked at the minimum intervals set forth above on days when water is withdrawn and also a minimum of 24 hours prior to the initiation of withdrawal to establish that the pass-by flow meets the minimum requirement. No water withdrawal may be initiated at the WBLR withdrawal site until an operating gage is established and a monitoring and reporting program is in effect in accordance with the requirements of the Operations Plan and conditions of this docket.

Operations Plan

In accordance with Condition t. of the Decision section of the docket, at least 90 days prior to the scheduled initiation of any site clearing or construction at the WBLR withdrawal site, the docket holder shall submit an Operations Plan (OP) for the WBLR withdrawal site to the Executive Director. The OP shall include the specifics of the site operations, which shall including, at a minimum, the procedures necessary to comply with the conditions in the Decision section of this docket. In accordance with Condition s. in the Decision section of the docket, no withdrawal of surface water from the WBLR withdrawal site is permitted until the OP is approved by the Executive Director in writing and all systems and equipment required to comply with this docket are operational.

The project is designed to conform to the requirements of the *Water Code* and *WQR* of the DRBC. Commission staff has imposed requirements and limitations to protect the water resources of the basin. For on-site water withdrawal actions and activities related to the water withdrawal actions, Commission staff has included conditions in the Decision section of this docket.

The DRBC estimates that the project withdrawals will result in a consumptive use of 100 percent of the total water withdrawn from the WBLR. The DRBC definition of consumptive use is defined in Article 5.5.1.D of the *Administrative Manual – Part III – Basin Regulations – Water Supply Charges*. This withdrawal is not at present subject to water supply charges as the point of withdrawal is located above the USGS stream gaging station at Montague, NJ. The docket holder shall be subject to any future water supply charges applicable to withdrawals located above the Montague gaging station resulting from any changes to the DRBC's existing water supply regulations.

The project does not conflict with the Comprehensive Plan and is designed to prevent substantial adverse impact on the water resources related environment, while sustaining the current and future water uses and development of the water resources of the Basin.

C. DECISION

I. Effective on the approval date for Docket No. D-2009-13-1 below the project and appurtenant facilities as described in Section A "Description" are approved pursuant to Section 3.8 of the *Compact*, subject to the following conditions:

a. The project and the appurtenant facilities described in Section A "Description" shall be added to the Natural Gas Well & Withdrawal Database maintained by the DRBC.

b. Docket approval is subject to all conditions, requirements, and limitations imposed by the PADEP, and such conditions, requirements, and limitations are incorporated herein, unless they are less stringent than the Commission's.

c. Nothing herein shall be construed to exempt the docket holder from obtaining all necessary permits and/or approvals from other State, Federal or local government agencies having jurisdiction over this project or activities associated with this project.

d. No new construction, addition or modification shall be permitted unless the lowest operating floor of such facility is above the Flood Protection Elevation, or the facility is flood proofed according to plans approved by the Commission, nor unless emergency plans and procedures for action to be taken in the event of flooding are prepared. Plans shall be filed with the Delaware River Basin Commission and the concerned state or states. The emergency plans and procedures shall provide for measures to prevent introduction of any pollutant or toxic material into the flood water or the introduction of flood waters into potable supplies.

e. Final construction plans and specifications must be submitted by the docket holder and be approved by the Executive Director of the DRBC before any water withdrawal, site clearing, site preparation, or construction commences at the withdrawal site.

f. Upon completion of construction of the approved project, the docket holder shall submit a statement to the DRBC, signed by the docket holder's engineer or other responsible agent, advising the Commission that the construction has been completed in compliance with the approved plans, and stating the final construction cost of the approved project and the date the project is placed in operation.

g. This docket approval shall expire three years from Approval Date set fourth below unless prior thereto the docket holder has commenced operation of the subject project or has expended substantial funds (in relation to the cost of the project) in reliance upon this docket approval.

h. The docket holder shall follow sound practices of excavation, backfill and reseeding at the WBLR withdrawal site to minimize erosion and prevent non-point source pollutants from leaving the site. The docket holder shall abide by all state and local erosion and sediment control, state stream bank disturbance permits, local floodplain development requirements and post-construction storm water management control requirements.

i. The docket holder shall submit a Non-Point Source Pollution Control Plan (NPSPCP) for the WBLR withdrawal site in accordance with Section 3.10.3.A.2.e, of the DRBC Water Quality Regulations to the Executive Director of the DRBC at least 45 working days prior to the scheduled initiation of any site clearing or construction at the site. The NPSPCP and erosion and sedimentation control plan shall be designed in accordance with the more stringent of Commission and PADEP requirements. Prior to commencing any site clearing or construction work at the WBLR withdrawal site, the docket holder shall obtain Executive Director's written approval for the NPSPCP, as well as, any other necessary federal, state, and local authorizations. The NPSPCP shall describe erosion and sedimentation controls to be implemented at the site and shall include measures to control stormwater both during and post construction. The post-construction portion of the plan shall describe the final site conditions including a pre- and post-construction project hydrograph analysis, permanent facilities, equipment, access roads, and all sediment and erosion and stormwater control structures necessary after final site restoration has been achieved.

j. Nothing herein shall be construed to grant the docket holder Commission approval or permission to commence any natural gas well development and extraction activities in the Delaware River Basin targeting shale formations including, but not limited to; preparing any natural gas well sites, drilling any natural gas well, stimulating any natural gas well, or storing, transporting, or disposing of any natural gas well hydro-fracturing or flow-back fluid.

k. This surface water withdrawal shall only be used in support of the docket holder's natural gas development and extraction activities targeting shale formations within the drainage area of Special Protection Waters within the Delaware River Basin (DRB) in the Commonwealth of Pennsylvania for which both the Commission and the PADEP have issued approvals as more fully described in Section A.3 Area/Wells Served in the Description section of this docket. The docket holder must obtain the Commission modification of this docket before using any water withdrawn from the Stone WBLR Withdrawal Site beyond the locations and/or outside of the scope of activities described in Section A.3. Area/Wells Served.

l. The docket holder shall make the surface water withdrawal location, associated natural gas well pad sites, associated natural gas wells, and operational records associated with any water withdrawal at the WBLR withdrawal site (or at an alternative site approved in writing by the Executive Director) available at all times for inspection by the DRBC and PADEP as appropriate.

m. No water withdrawal from the WBLR shall commence until the docket holder has received approval of the Commission and PADEP natural gas development and extraction activities targeting shale formations within the drainage area of Special Protection Waters within the Delaware River Basin (DRB) in the Commonwealth of Pennsylvania.

n. Total surface water withdrawals from the project Intake No. 001 shall not exceed 0.7 mgd. The instantaneous rate of withdrawal from Intake No. 001 shall not exceed 1,040 gpm. Withdrawals are subject to the limitations in Condition I.m. below. A “day” is defined as the 24-hour period between 12:00 AM and 12:00 AM the following day.

o. The project withdrawal must not cause the streamflow in the WBLR to be less than 5.9 cfs at the point of taking at the Stone WBLR gage. The WBLR withdrawal site shall be fitted by the docket holder with a gage (the Stone WBLR gage) or another gage or other instrumentation approved by the Executive Director and calibrated to the downstream Aldenville gage station flow data. The installed gage shall be a real-time monitoring and recording gage. Daily withdrawal rates shall be reduced as appropriate to ensure that the project withdrawal does not cause the stream flow in the WBLR to be less than 5.9 cfs as measured at the Stone WBLR gage. Whenever the 24-hour average stream flow at the Stone WBLR gage, less the Stone WBLR water withdrawal, is less than or equal to this amount, no withdrawal shall be made and the entire stream flow must be allowed to pass. Withdrawal from the WBLR at the WBLR withdrawal site shall not resume until the flow as measured the Stone WBLR gage is at least 8.2 cfs for a 24 hour period. Whenever the flow at the Stone WBLR gage is 10 cfs or more, the docket holder shall check the Stone WBLR gage and the USGS Aldenville gage station a minimum of once per week through direct observation and real time flow provided by the USGS website. Whenever the 24-hour average flow at the Stone WBLR gage is less than 10 cfs the docket holder shall check the Aldenville gaging station and Stone WBLR gage on a daily basis to ensure compliance with the 5.9 cfs pass-by flow. The docket holder is required to check the flow gages at the intervals set forth above only on days when water is withdrawn and shall also check the flow gages a minimum of 24 hours prior to the withdrawal to establish that the pass-by flow meets the minimum requirements.

p. Before commencing construction on the surface water withdrawal intake at the WBLR withdrawal site, the docket holder shall first obtain the approval of the intake design from the Commission, PAF&BC, the USACE and U.S. Fish & Wildlife Service. The intake shall be designed to minimize to the greatest extent possible, impingement and entrainment impacts in the vicinity of the withdrawal site. The docket holder shall provide the Commission with a copy of the intake design, and shall provide the Commission with copies of all correspondence between the docket holder and the other government agencies reviewing the intake design at the time the correspondence is sent or received.

q. Water withdrawn from the Stone's WBLR withdrawal site shall only be transported in water hauling tanks that are free of contaminates (except for the chemicals added as part of the Invasive Species Control Plan (ISCP)). Prior to the transfer of any water to a water hauling vehicle, the onsite pump operator shall verify that the water tank interior is clean and that the tank is dedicated for the use of hauling of fresh water.

r. The docket holder shall not allow any unused water withdrawn from the WBLR withdrawal site, fresh or otherwise, to be discharged to waters of the DRB without the advance written approval of the DRBC and the appropriate state agency or outside the DRB without the written approval of the appropriate state agency. The docket holder shall convey all wastewater created as a result of natural gas development and extraction activities undertaken with water withdrawn from the WBLR withdrawal site to treatment and disposal facilities approved by the DRBC and by the appropriate state and or federal agency (if in the DRB and subject to Commission approval), or if outside the DRB, by the appropriate state and/or federal agency.

s. If determined to be applicable, the docket holder shall submit to the DRBC an Invasive Species Control Plan (ISCP) with the Operation Plan required in Condition t. below. The ISCP shall include the management and treatment program that the docket holder will implement to ensure that all water withdrawn from the Stone WBLR Withdrawal Site prior to distribution to the transportation vehicles is managed or treated to prevent the spread of potentially invasive, harmful, or nuisance species from entering other watersheds in the DRB. The docket holder shall comply with the ISCP approved by the Executive Director.

t. At least 90 days prior to the scheduled initiation of any site clearing or construction and prior to commencement of any withdrawal operations at the Stone WBLR withdrawal site, the docket holder shall submit an Operation Plan to the DRBC. No withdrawal, site clearing or construction shall commence until the docket holder has received the Executive Director's written approval of the Operation Plan. The docket holder shall comply with the Operation Plan approved by the Executive Director. The Operation Plan shall include a procedures for metering, recording, and reporting the pass-by flow and for complying with the pass-by flow requirements, as well as, procedures for monitoring, reporting and recording the usage, transport, and destination of all water withdrawn from the site. The Executive Director may require real time monitoring, reporting and recording as part of the Operation Plan.

u. The docket holder shall meter the project surface water withdrawals with an automatic continuous recording device that measures to within 5 percent of actual flow. An exception to the 5 percent performance standard, but no greater than 10 percent, may be granted if maintenance of the 5 percent performance is not technically feasible or economically practicable. A record of average daily flow rate and daily and monthly totals of the withdrawal shall be maintained. Unless the approved Operation Plan provides otherwise, the docket holder shall at a minimum, submit an electronic copy of this record to the Commission by the 5th calendar day of the month following the month in which the operations occurred beginning with the month that water withdrawal operations commence. In addition the docket holder shall make such record(s) available at any time to the Commission or the PADEP if requested by the

Executive Director. The docket holder shall also submit a record of monthly withdrawal use totals to the PADEP annually. The docket holder shall register with the PADEP all surface water sources described in this docket in accordance with the Pennsylvania Regulations (Title 25 - Environmental Protection, [25 PA. CODE CH. 110], Water Resources Planning).

v. Unless the approved Operation Plan provides otherwise, the docket holder shall meter, record, and report the volume of surface water withdrawn from the on-site storage tanks as it is distributed to the hauling vehicles. Records maintained by the docket holder shall be kept at the WBLR withdrawal site (or at an alternative site approved in writing by the Executive Director). The records shall include the trucking company name, license plate number, name of the driver, amount of water transferred, date and time of transfer and destination of the transported water. Daily records of the amounts of the water withdrawals shall be automatically metered and recorded by the flow meter. The docket holder shall report this information to the Commission at the same frequency as provided in Condition u. above. In addition the docket holder shall make the WBLR withdrawal site records available at any time to the Commission and PADEP for inspection, if requested by the Executive Director.

w. In accordance with DRBC Resolution No. 87-6 (Revised), the docket holder shall continue to implement to the satisfaction of the DRBC, the systematic program to monitor and control leakage within the water supply system. The program shall at a minimum include: periodic surveys to monitor leakage, enumerate unaccounted-for water and determine the current status of system infrastructure; recommendations to monitor and control leakage; and a schedule for the implementation of such recommendations. The docket holder shall proceed expeditiously to correct leakages and unnecessary usage identified by the program.

x. The docket holder shall implement to the satisfaction of the Commission, the continuous program to encourage water conservation in all types of use within the facilities served by this docket approval. This includes the reuse and recycling of flow-back waters for well stimulation activities to the greatest extent economically and technically feasible at natural gas well drilling sites targeting shale formations within the drainage area of Special Protection Waters within the Delaware River Basin (DRB) in the Commonwealth of Pennsylvania. The docket holder shall report annually to the Commission on the actions taken pursuant to this program and the impact of those actions.

y. A complete application for the renewal of this docket, or a notice of intent to cease the operations (withdrawal, discharge, etc.) approved by this docket by the expiration date, must be submitted to the DRBC, to the attention of the Project Review Section, at least 12 months prior to the expiration date below (unless written permission has been granted by the Executive Director for submission at a later date), using the appropriate DRBC application form. In the event that a timely and complete application for renewal has been submitted and the DRBC is unable, through no fault of the docket holder, to reissue the docket before the expiration date below, the terms and conditions of this docket will remain fully effective and enforceable against the docket holder pending the grant or denial of the application for docket approval.

z. The issuance of this docket approval shall not create any private or proprietary rights in the water of the Basin, and the Commission reserves the rights to amend, alter or rescind any actions taken hereunder in order to insure the proper control, use and management of the water resources of the Basin.

aa. Drought Plan - At least 90 days prior to the scheduled initiation of any site clearing or construction and prior to commencement of any withdrawal operations at the WBLR withdrawal site, the docket holder shall submit a drought emergency plan to the DRBC.

bb. Drought Emergencies - For the duration of any drought emergency declared by either Pennsylvania or the Commission, water service or use by the docket holder pursuant to this approval shall be subject to the prohibition of those nonessential uses specified by the Governor of Pennsylvania, the Pennsylvania Emergency Management Council, PADEP, or the Commonwealth Drought Coordinator to the extent that they may be applicable, and to any other emergency resolutions or orders adopted hereafter by the Commission.

cc. The Commission has determined that the review of the reports and submissions developed under the above docket conditions, inspections and any amendments or changes thereto will continue to cause the Commission to expend exceptional efforts and costs. As such, Commission staff will continue to maintain a record of all time and expenses associated with the post-docket approval reviews of the project and associated deliverables. A fee in the amount of 100% of these costs will be assessed on a quarterly basis and the docket holder shall pay the amount assessed within thirty days of the date of the assessment. In the event of a docket amendment or renewal, the larger of actual project review costs or the calculated project review fee will be charged.

dd. The docket holder and any other person aggrieved by a reviewable action or decision taken by the Executive Director or Commission pursuant to this docket may seek an administrative hearing pursuant to Articles 5 and 6 of the Commission's *Rules of Practice and Procedure,* and after exhausting all administrative remedies may seek judicial review pursuant to Article 6, section 2.6.10 of the *Rules of Practice and Procedure* and section 15.1(p) of the Commission's *Compac*t.

ee. Failure to comply with any of the terms and conditions of this docket may result in sanctions by the Commission in accordance with Section 14.17 of the Compact and the Commission’s regulations including without limitation its Rules of Practice and Procedure.

ff. The docket holder shall report to the Commission Project Review Section Supervisor any violation of the docket conditions within 48-hours of the occurrence or upon the docket holder becoming aware of the violation. In addition, the docket holder shall report in writing any violations of the pass by requirements, the daily or monthly water allocations, the approved operations plan or any other docket conditions to the DRBC Project Review Section Supervisor within three days of the violation. The docket holder shall also provide a written explanation of the causes of the violation within 30 days of the violation and shall set forth the action(s) the docket holder has taken to correct the violation and protect against a future violation.

gg. If the surface water withdrawal operations associated with this docket approval significantly affects or interferes with any domestic or other existing wells or surface water supplies, or if the docket holder receives a complaint by any user of wells or surface water supplies, the docket holder shall immediately notify the Executive Director of any such affects, interferences or complaints and unless excused by the Executive Director, shall investigate such affects, interferences or complaints. The docket holder shall also advise the complainants that they may also direct their phone call notifications of potential interference complaints to the DRBC Project Review Section at 609-883-9500, extension 216. Oral notification by the docket holder must always be followed up in writing or via email directed to the Executive Director. In addition, the docket holder shall provide written notification to all complainants of the docket holder's responsibilities under this condition. Any well or surface water supply which is substantially adversely affected, or otherwise rendered unusable as a result of the docket holder's project withdrawal, shall be repaired, replaced or otherwise mitigated at the expense of the docket holder. The docket holder shall prepare a report of investigation and/or mitigation plan prepared by a qualified professional and shall submit the report to the Executive Director as soon as practicable or as directed by the Executive Director. The Executive Director shall make the final determination, subject to the right of appeal, regarding the validity of such complaints, the scope or sufficiency of such investigations, and the extent of appropriate mitigation measures, if required.

hh. The Executive Director may modify or suspend this approval or any condition thereof, or require mitigating measures pending additional review, if in the Executive Director's judgment such modification or suspension is required to protect the water resources of the Basin.

ii. The docket holder shall pay any water supply charges that become applicable to the withdrawal authorized by this Docket as a result of any change to the Commission's water supply charge regulations.

BY THE COMMISSION

APPROVAL DATE: July 14, 2010

EXPIRATION DATE: July 14, 2015

Subject:
From: "Randis, Thomas" <trandis@state.pa.us>
Date: Fri, 05 Feb 2010 07:57:37 -0500
To: "'David.Kovach@drbc.state.nj.us'" <David.Kovach@drbc.state.nj.us>
CC: "Hawley, Robert" <rhawley@state.pa.us>, "Miller, Chad (DEP)" <chadmiller@state.pa.us>, "Engle, David" <daengle@state.pa.us>

Good Morning Dave,

Valley Joint SA was contacted regarding the acceptance of this top-hole water. The Authority is adamant that they have not taken any further drilling water/wastewater/fluids since DEP sent them a letter in April 2009 requesting a permit amendment if they want to continue accepting these types of wastewaters. It is possible that they accepted this material prior to this date. If Stone Energy is insistent that the top-hole water was disposed of at this facility, either it was prior to April 2009 or there is a disconnect in disposal sites. Thanks Tom

Thomas Randis | Environmental Group Manager
Department of Environmental Protection
208 West Third Street, Suite 101, Williamsport, PA 17701
Phone: (570) 327-3781 | Fax: (570) 327-3565
www.depweb.state.pa.us

----Original Message-----
From: David Kovach [mailto:David.Kovach@drbc.state.nj.us]
Sent: Thursday, February 04, 2010 10:16 AM
To: Miller, Chad (DEP)
Subject: Valley Joint Sewer Authority in Athens, PA

Hi Chad,
Are you aware that the Valley Joint Sewer Authority in Athens, PA apparently accepted water produced during the drilling of the Stone Energy, Matoushek 1 natural gas well. Most of the water was fresh tophole water with potassium chloride as a drilling additive totalling approximately 270,000 gallons. Was the authority approved to take this water? Is there any concerns with accepting these types of wastes. Any help would be appreciated.
Thanks,
Dave

--
David Kovach, P.G.
Geologist, Project Review Section
Delaware River Basin Commission
(p) 609-883-9500 ext 264
(f) 609-883-9522
(e) david.kovach@drbc.state.nj.us

Subject: DRBC Data request
From: "Stiles, Kevin" <StilesEK@StoneEnergy.com>
Date: Mon, 25 Jan 2010 14:07:44 +0000
To: "'david.kovach@drbc.state.nj.us'" <David.Kovach@drbc.state.nj.us>

David:

My technical staff has assembled the information below to answer your questions of last Thursday 1.21. Please let us know if you require any additional information. Looking forward to seeing you at our hearing in February.

Best Regards/Kevin

Kevin Stiles
Appalachia Manager
Stone Energy
6000 Hampton Center Suite E
Morgantown WV 26505
337-291-7783
304-216-1083 Cell
StilesEK@StoneEnergy.com

Matoushek #1 top hole drilling summary:

- Drilled 24" hole from surface to 60'
- 0 – 50', till/gravel/pebbles, drilled on air, hole damp
- 50' – 60', bedrock, drilled on air, hole dry
- 24" conductor pipe set at 60'
- Drilled 17-1/2" hole from 60' to 710'
- 60' – 650', gray shale/siltstone, drilled on air/mist, hole damp
- **650' – 665', significant FW zone**, ~3000 bbls FW to surface (aka 3000 bbls of tophole water)
- 665' – 710', gray shale/siltstone, drilled on air/mist, hole wet from above FW zone
- 13-3/8" conductor casing set at 710' (cemented to surface)
- Drilled 12-1/4" hole from 710' to 1964'
- 710' – 1964', gray shale/siltstone, drilled on air/mist, hole damp, gained 1 to 1.5 bbl/hr water while drilling (~50 bbls FW to surface / tophole water)
- Note: since the hole was damp and "making water" just below the 13-3/8" shoe, the ~50 bbls of water came from near the shoe
- **Note: no significant FW or salt water zones were encountered while drilling the 12-1/4" hole**
- 9-5/8" surface casing set at 1964' (cemented to surface)
- Drilled 8-3/4" hole below 1964', drilled on air/dusted, hole dry, no water zones encountered

1) Depth of all fresh water horizons:
   - 0 – 50', till/gravel/pebbles, hole damp
   - 50' – 650', gray shale/siltstone, hole damp
   - **650' – 665', significant FW zone (~3000 bbls of tophole water)**
   - 665' – approximately 750', gray shale/siltstone, hole wet (~50 bbls of tophole water)
2) Depth of all salt water horizons:
   - No significant salt water horizons were encountered
3) Disposal of salt water in 2) above:

- No significant salt water horizons were encountered

5500-FM-OG0001A Rev. 11/2007

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL AND GAS MANAGEMENT PROGRAM

WELL PERMIT

DEP USE ONLY	
Permittee's eFACTS ID 246326	Auth ID 760352
Watershed Name Holbert Creek	Quality HQ

Permittee CHESAPEAKE APPALACHIA, LLC		OGO.# OGO-65420	Permit Number 37-127-20008-00	Date Issued 02/26/2009
Address 900 PENNSYLVANIA AVE			Farm Name & Well Number ROBSON 627528 1	Well Serial #
			Municipality Oregon	County Wayne
CHARLESTON, WV 25302			7½ ' Quadrangle Name Galilee	Map Section # 8
Phone (304) 353-5120	Project #		Latitude 41-37-39.5200	Longitude -75-12-11.6000
Surf Elev at Site 1493 feet	Anticipated Total Depth 8898 feet	Well Type GS	Offset distances referenced to NE corner of map section. South 14207 feet West 9985 feet	

This permit covering the well operator and well location shown above is evidence of permission granted to conduct activities in accordance with the Oil and Gas Act and the Oil and Gas Conservation Law, if the well is subject to that act and any rules and regulations promulgated thereunder, subject to the conditions contained herein and in accordance with the application submitted for this permit. This permit does not convey any property rights.

This permit and the permittee's authority to conduct the activities authorized by this permit are conditioned upon operator's compliance with applicable law and regulations.

Notification must be given to the district oil and gas inspector, the surface landowner and political subdivision of the date well drilling will begin at least 24 hours prior to commencement of drilling activities.

The permittee hereby authorizes and consents to allow, without delay, employees or agents of the Department to have access to and to inspect all areas upon presentation of appropriate credentials, without advance notice or a search warrant. This includes any property, facility, operation or activity governed by the Oil and Gas Act, the Oil and Gas Conservation Law, the Coal and Gas Resource Coordination Act and other statutes applicable to oil and gas activities administered by the Department. The authorization and consent shall include consent to the Department to collect samples of wastewaters or gases, to take photographs, to perform measurements, surveys, and other tests, to inspect any monitoring equipment, to inspect the methods of operation and disposal, and to inspect and copy documents required by the Department to be maintained. The authorization and consent includes consent to the Department to examine books, papers, and records pertinent to any matter under investigation pursuant to the Oil and Gas Act or pertinent to a determination of whether the operator is in compliance with the above referenced statutes. This condition in no way limits any other powers granted to the Department under the Oil and Gas Act and other statutes, rules and regulations applicable to these activities as administered by the Department.

This permit does not relieve the operator from the obligation to comply with the Clean Streams Law and all statutes, rules and regulations administered by the Department.

Special Permit Conditions:

This permit expires **02/26/2010** unless drilling is commenced on or before that date and prosecuted with due diligence.

S. Craig Lobins
Regional Oil and Gas Program Manager

HERB KARLINSEY
Oil and Gas Inspector

P O Box 673, Coudersport, PA 16915-0673
Address

814-274-3611
Telephone

5500-PM-OG0001 Rev. 9/2007

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL & GAS MANAGEMENT PROGRAM

DEP USE ONLY	
AUTH #	CNC
Check # 686000121 2	Amount $ 350,00

PERMIT APPLICATION FOR DRILLING OR ALTERING A WELL

DEP USE ONLY			
Notes	OGO # 65420 Bond # 10611 C: 1/20/09 ... G: 2/19/09 ... INV: 225-09	Objection Date - Do not issue before: 2/19/09 Date Approved:	Well Permit # 127-20008 Special Cond. A B C D E F Watershed Name: HOLBERT CREEK Designation: HQ EV

Please read instructions before you begin filling in this form.

Applicant (Operator) Name	DEP Client ID#	Phone		FAX	Check if new address. ☐
Chesapeake Appalachia L.L.C.	246326	304-353-5120		304-353-5231	
Mailing Address (Street or PO Box): 900 Pennsylvania Avenue	City: Charleston		State: WV	Zip +4: 25302	Country (If not USA)

(Well) Farm Name	Well #	Serial #
Robson (627528)	1	

County	Municipality	Project # (from DEP)
Wayne	Oregon Township	

If you are applying for a permit to redrill, drill deeper, or alter a well that was previously permitted or registered, ***or for a well site that was previously permitted but not drilled,*** check this box ☐ and enter the permit or registration number here:

If applying for a permit to rework an existing well not registered or permitted, check this box ☐ and enter date drilled, if known:__________ (see instructions)

PNDI Attached: ☒ Any "hit" must include accepted mitigation plan from applicable agency.

PERMIT TYPE
Check one.
Application is to:
☒ Drill a new well
☐ Deepen a well
☐ Redrill a well
☐ Alter a well
☐ Other (specify)

TYPE OF WELL
Check one.
☒ Gas
☐ Oil
☐ Comb. (gas & oil)
☐ Injection, recovery
☐ Disposal
☐ Coalbed Methane
☐ Gas Storage
☐ Other (specify)

APPLICATION FEE
Check one.
☒ $ 350 (Gas; Comb.; Coal Meth; Storage)
☐ $ 250 (Oil; Inj– Rec)
☐ $ 150 (Injection – Waste Disposal)
☐ $ 100 (Redrill, Drill Deeper, Alter a Well, or Change Use)
☐ $ 0 (Rehab orphan)

COORDINATION WITH REGULATIONS AND OTHER PERMITS	Yes	No
1. Will the well be subject to the **Oil and Gas Conservation Law**? If "No," go to 2).	☒	☐
a. If "Yes" to #1, is the well at least 330 feet from outside lease or unit boundary?	☐	☒
b. Does the location fall within an area covered by a spacing order?	☐	☐
2. Will the well penetrate a **workable coal seam**? If "No," include justification and supporting documentation.	☐	☒
3. If the well will penetrate a **workable coal seam**, and the well is a "non-conservation" gas well, does the location comply with the distance requirements of Section 7 of the Coal and Gas Resource Coordination Act? (At least 1,000 feet from all existing wells).	☐	☐
a. If "No," is the required exception request attached? (Check here if re-working an existing well: ☐ N/A)	☐	☐
4. Will the well be drilled at a location where the **coal** has been removed?	☐	☒
5. Will the well be drilled through an **active (operating or projected) coalmine**, or within 1,000 feet of the boundary?	☐	☒
a. If "Yes," print the names of: Mine: Operator:		
6. Will the well penetrate or be within 2,000 feet of an active **gas storage reservoir** boundary?	☐	☒
a. If Yes, print the names of: Storage Field: Operator:		
7. Is the proposed well location within the permitted area of a **landfill**?	☐	☒
8. Will the well site be within 100 feet (measured horizontally) of a **stream, spring or body of water** identified on the most current 7½' topographic map?	☐	☒
a. If "Yes," is a request for a waiver (form 5500-FM-OG0057), and E&S control plan attached?	☐	☐
9. Will the well site be within 100 feet of a **wetland** or in a **wetland**?	☐	☒
a. Is the well site within 100 feet of a wetland greater than one acre in size?	☐	☐
If yes, is a waiver request (form 5500-FM-OG0057) and E&S control plan attached?	☐	☐
10. Will the well be drilled within 200 feet (horizontally) from any existing **building** or an existing **water supply**?	☐	☒
a. If "Yes," is written consent from the owner attached?	☐	☐
b. If written consent is not attached, is a variance request (form 5500-FM-OG0058) attached?	☐	☐
11. Will the well be located where it may impact a public resource as outlined in the "**Coordination of a Well Location with Public Resources**" form 5500-PM-OG0076? If yes, attach a competed copy of the form.	☐	☒
12. Is the well site in a **Special Protection** High Quality (HQ) or Exceptional Value (EV) watershed?	☒	☐
13. Is this well part of a development where you need an **Earth Disturbance Permit** for Oil and Gas Activities disturbing more than 5 acres?	☐	☒

RECEIVED
JAN 13 2009
ENVIRONMENTAL PROTECTION
NORTHWEST REGIONAL OFFICE

DEP USE ONLY
Date Stamps/Notes
Auth 760352
Site 716805
Clnt 246326
APS 667547
Acct 634818
PF 715590
SF 984685

Signature of Applicant: The person signing this form attests that they have the authority to submit this application on behalf of the applicant, and that the information, including all related submissions, is true and accurate to the best of their knowledge.

Signature of Person Authorized to Submit Application	(Print or Type)	Name of Signer: Michael John Title: Vice President	Date 1/9/09

Application Preparer/Contact: Rachelle A. King Phone: 304-391-5588

127-20008

5500-PM-OG0001 Rev. 9/2007

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL & GAS MANAGEMENT PROGRAM

Farm Name - Well #	
Robson 1 (627528)	
Applicant Name	DEP ID#
Chesapeake Appalachia L.L.C.	246326
DEP USE ONLY	APS #

PERMIT APPLICATION FOR DRILLING OR ALTERING A WELL

Page 2 --- Record of Notification / Written Consent

List the following: surface landowner; all landowners or water purveyors whose water supplies are within 1,000 feet of this proposed well location; gas storage operator if within 2000 feet; all coal owners and lessees of all underlying workable coal seams; operators of underground coal mines at the proposed location; and coal operators with a deep mine within 1,000 feet. Mark the boxes, "X," which show the parties' interests. Use additional forms if you need more space. You are required to notify each of these parties.

Name	Address	Surface Landowner	Coal Owner	Coal Lessee	Coal Mine Operator	Gas Storage Operator	Within 1,000 feet: Surf Owner with Water	Within 1,000 feet: Water Purveyor	Within 1,000 feet: Coal Mine Operator	Notification (Note the means and attach proof.) Certified Mail Dates: Sent	Certified Mail Dates: Return Receipt	Address Affidavit	Written Consent
Christopher and Betty Robson	45 Ripple Lane Honesdale, PA 18431	X								12/2/08	12/5/08		12/7/08
David S. & Diane L. Richter	455 Fox Hill Road Honesdale, PA 18431							X					
James II & Beverly Ludwig	434 Fox Hill Road Honesdale, PA 18431							X					
Anthony J & Judy Novena	404 Fox Hill Road Honesdale, PA 18431							X					
Mark P. Leunes	240 Brill Rd Honesdale, PA 18431							X					

RECEIVED
FEB 0 5 2009
ENVIRONMENTAL PROTECTION
NORTHWEST REGIONAL OFFICE

RECEIVED
JAN 13 2009
ENVIRONMENTAL PROTECTION
NORTHWEST REGIONAL OFFICE

Optional: Signature below indicates the party's approval of the well location, and waives the 15-day objection period. Check applicable box.

	Date		Date
☐ Water Purveyor or ☐ Landowner with water supply within 1,000 ft.	Date	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
☐ Water Purveyor or ☐ Landowner with water supply within 1,000 ft.	Date	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
☐ Water Purveyor or ☐ Landowner with water supply within 1,000 ft.	Date	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
☐ Water Purveyor or ☐ Landowner with water supply within 1,000 ft.	Date	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
Surface Landowner at proposed location [signature]	Date 12/7/08	Coal Operator within 1,000 feet of proposed location	Date
Surface Landowner at proposed location Betty Ann Robson	Date 12/7/08	Gas Storage Operator within 2,000 feet	Date

Signature below indicates written consent. Check applicable box.

Owner of: ☐ water supply, or ☐ building within 200 feet	Date
Address (of above)	
Owner of: ☐ water supply, or ☐ building within 200 feet	Date
Address (of above)	

127-20008

5500-PM-OG0001 Rev. 9/2007

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL & GAS MANAGEMENT PROGRAM

Farm Name - Well #		DEP ID#
Robson 1 (627528)		
Applicant Name		
Chesapeake Appalachia L.L.C.		246326
DEP USE ONLY	APS #	

PERMIT APPLICATION FOR DRILLING OR ALTERING A WELL

Page 2 --- Record of Notification / Written Consent

List the following: surface landowner; all landowners or water purveyors whose water supplies are within 1,000 feet of this proposed well location; gas storage operator if within 2000 feet; all coal owners and lessees of all underlying workable coal seams; operators of underground coal mines at the proposed location; and coal operators with a deep mine within 1,000 feet. Mark the boxes, "X," which show the parties' interests. Use additional forms if you need more space. You are required to notify each of these parties.		Surface Landowner	Coal Owner	Coal Lessee	Coal Mine Operator	Gas Storage Operator	Within 1,000 feet: Surf Owner with Water	Within 1,000 feet: Water Purveyor	Within 1,000 feet: Coal Mine Operator	Notification (Note the means and attach proof.) Certified Mail Dates: Sent	Certified Mail Dates: Return Receipt	Address Affidavit	Written Consent
Name: Christopher and Betty Robson	Address: 45 Ripple Lane Honesdale, PA 18431	X											
Name: David S. & Diane L. Richter	Address: 455 Fox Hill Road Honesdale, PA 18431							X		12/2/08	12/4/08		✓
Name: James II & Beverly Ludwig	Address: 434 Fox Hill Road Honesdale, PA 18431							X					
Name: Anthony J & Judy Novena	Address: 404 Fox Hill Road Honesdale, PA 18431							X					
Name: Mark P. Leunes	Address: 240 Brill Rd Honesdale, PA 18431							X					
Name:	Address:												
Name:	Address:												

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Optional: Signature below indicates the party's approval of the well location, and waives the 15-day objection period. Check applicable box.

	Date		Date
☒ Water Purveyor or ☒ Landowner with water supply within 1,000 ft. David S. Richter	12/4/08	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
☒ Water Purveyor or ☐ Landowner with water supply within 1,000 ft. Diane L. Richter	12/4/08	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
☐ Water Purveyor or ☐ Landowner with water supply within 1,000 ft.	Date	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
☐ Water Purveyor or ☐ Landowner with water supply within 1,000 ft.	Date	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
Surface Landowner at proposed location	Date	Coal Operator within 1,000 feet of proposed location	Date
Surface Landowner at proposed location	Date	Gas Storage Operator within 2,000 feet	Date

Signature below indicates written consent. Check applicable box.

Owner of: ☐ water supply, or ☐ building within 200 feet	Date
Address (of above)	
Owner of: ☐ water supply, or ☐ building within 200 feet	Date
Address (of above)	

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COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL & GAS MANAGEMENT PROGRAM

Farm Name - Well # Robson 1 (627528)	
Applicant Name Chesapeake Appalachia L.L.C.	DEP ID# 246326
DEP USE ONLY	APS #

PERMIT APPLICATION FOR DRILLING OR ALTERING A WELL
Page 2 --- Record of Notification / Written Consent

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Name	Address	Surface Landowner	Coal Owner	Coal Lessee	Coal Mine Operator	Gas Storage Operator	Within 1,000 feet: Surf Owner with Water	Within 1,000 feet: Water Purveyor	Within 1,000 feet: Coal Mine Operator	Notification (Note the means and attach proof.) Certified Mail Dates: Sent	Certified Mail Dates: Return Receipt	Address Affidavit	Written Consent
Christopher and Betty Robson	45 Ripple Lane Honesdale, PA 18431	X											
David S. & Diane L. Richter	455 Fox Hill Road Honesdale, PA 18431							X					
James II & Beverly Ludwig	434 Fox Hill Road Honesdale, PA 18431							X		12/2/08	12/8/08		✓
Anthony J & Judy Novena	404 Fox Hill Road Honesdale, PA 18431							X					
Mark P. Leunes	240 Brill Rd Honesdale, PA 18431							X					

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Optional: Signature below indicates the party's approval of the well location, and waives the 15-day objection period. Check applicable box.

☐ Water Purveyor or ☒ Landowner with water supply within 1,000 ft. James R. Ludwig II	Date 12-15-08	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
☐ Water Purveyor or ☒ Landowner with water supply within 1,000 ft. Beverly Ludwig	Date 12-15-08	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
☐ Water Purveyor or ☐ Landowner with water supply within 1,000 ft.	Date	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
☐ Water Purveyor or ☐ Landowner with water supply within 1,000 ft.	Date	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
Surface Landowner at proposed location	Date	Coal Operator within 1,000 feet of proposed location	Date
Surface Landowner at proposed location	Date	Gas Storage Operator within 2,000 feet	Date

Signature below indicates written consent. Check applicable box.

Owner of: ☐ water supply, or ☐ building within 200 feet	Date
Address (of above)	
Owner of: ☐ water supply, or ☐ building within 200 feet	Date
Address (of above)	

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COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL & GAS MANAGEMENT PROGRAM

Farm Name - Well # Robson 1 (627528)	
Applicant Name Chesapeake Appalachia L.L.C.	DEP ID# 246326
DEP USE ONLY	APS #

PERMIT APPLICATION FOR DRILLING OR ALTERING A WELL

Page 2 --- Record of Notification / Written Consent

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Name: Christopher and Betty Robson	Address: 45 Ripple Lane Honesdale, PA 18431	X									RECEIVED		
Name: David S. & Diane L. Richter	Address: 455 Fox Hill Road Honesdale, PA 18431							X			FEB 05 2009 ENVIRONMENTAL PROTECTION NORTHWEST REGIONAL OFFICE		
Name: James II & Beverly Ludwig	Address: 434 Fox Hill Road Honesdale, PA 18431							X					
Name: Anthony J & Judy Novena	Address: 404 Fox Hill Road Honesdale, PA 18431			RECEIVED				X		12/2/08	12/5/08		✓
Name: Mark P. Leunes	Address: 240 Brill Rd Honesdale, PA 18431			JAN 13 2009				X					
Name:	Address:			ENVIRONMENTAL PROTECTION NORTHWEST REGIONAL OFFICE									
Name:	Address:												

Optional: Signature below indicates the party's approval of the well location, and waives the 15-day objection period. Check applicable box.

☐ Water Purveyor or ☐ Landowner with water supply within 1,000 ft. anthony + Judith Novena	Date 12-10-08	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
☐ Water Purveyor or ☐ Landowner with water supply within 1,000 ft.	Date	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
☐ Water Purveyor or ☐ Landowner with water supply within 1,000 ft.	Date	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
☐ Water Purveyor or ☐ Landowner with water supply within 1,000 ft.	Date	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
Surface Landowner at proposed location	Date	Coal Operator within 1,000 feet of proposed location	Date
Surface Landowner at proposed location	Date	Gas Storage Operator within 2,000 feet	Date

Signature below indicates written consent. Check applicable box.

Owner of: ☐ water supply, or ☐ building within 200 feet	Date
Address (of above)	
Owner of: ☐ water supply, or ☐ building within 200 feet	Date
Address (of above)	

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COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL AND GAS MANAGEMENT PROGRAM

WELL LOCATION PLAT

DEP USE ONLY	Auth ID #:	2/19/09 G: JL
	Permit #: 127-20008	
	Project #	C:

Well is located on topo map 14,207 feet south of latitude 41 ° 40 ' 00 "

Well is located on topo map 9,985 feet west of longitude 75 ° 10 ' 00 "

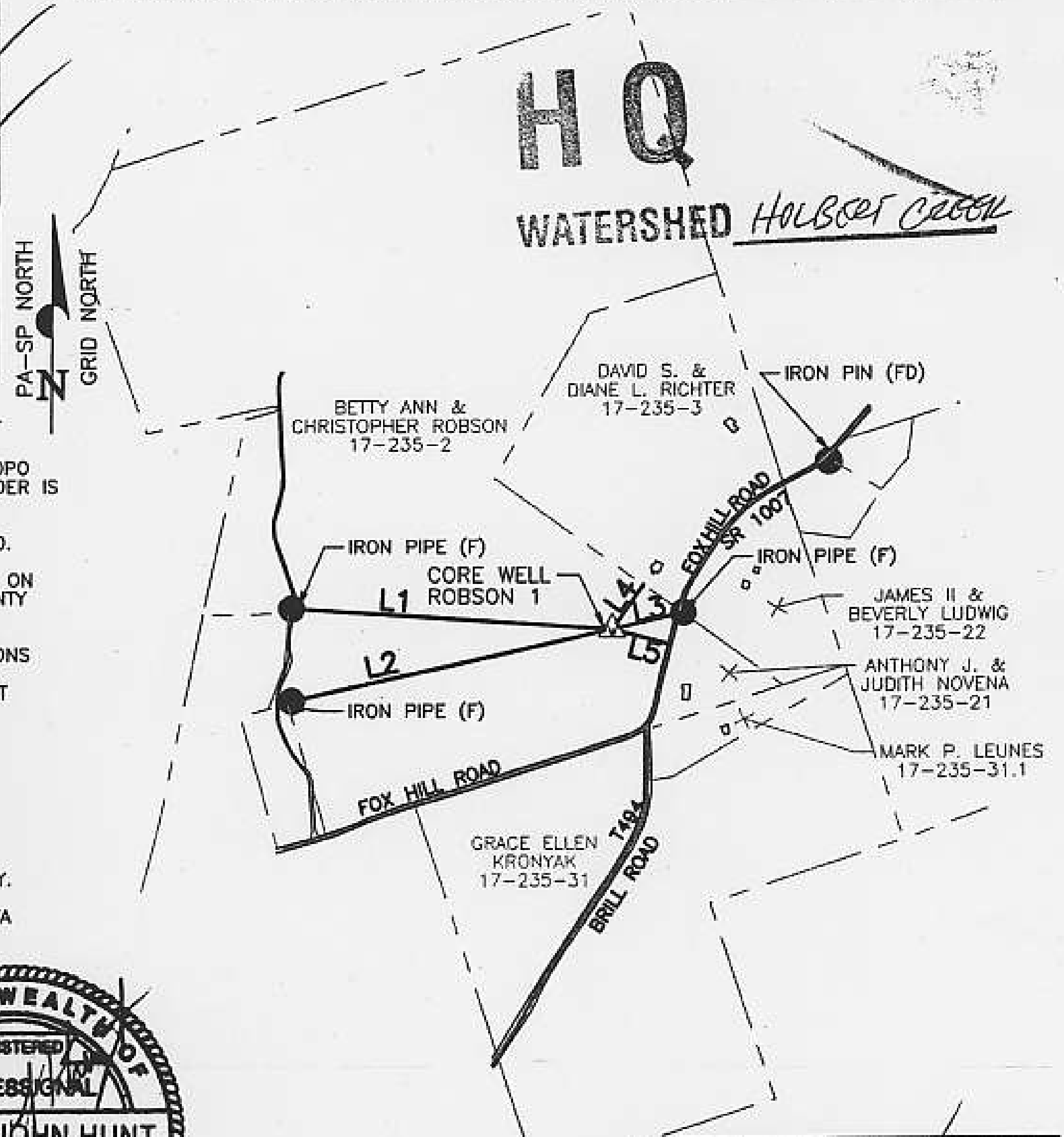
Denotes location of well on topo map. SEE NOTE 1

True Latitude: NORTH NAD 83
41 ° 37 ' 39.52 "

True Longitude: WEST
75 ° 12 ' 11.60 "

True Latitude: NORTH NAD 27
41.62756°

True Longitude: WEST
75.203625°



NOTES:

1. WELL LOCATION POSITION ON A 7.5', 1:24,000 USGS TOPO QUAD WHEN THIS SHEET BORDER IS ADJUSTED TO SCALE AND OVERLAYED AND ORIENTED TO THE RESPECTIVE SECTION GRID.

2. PLAN INFORMATION SHOWN ON THIS PLAT IS BASED ON COUNTY TAX PARCELS, DEED PLOTS, AND BASE DATA FROM PASDA AND USGS. SURVEYED LOCATIONS WERE SOLVED USING DUAL FREQUENCY GPS (L1/L2) THAT WAS POST-PROCESSED WITH THE NGS OPUS SERVICE.

3. THIS PLAT IS FOR WELL LOCATION PURPOSES ONLY. IT IS NOT A BOUNDARY RETRACEMENT SURVEY. TIES TO PINS OR PIPES FOUND IS PROVIDED FOR GAS WELL RE-LOCATION PURPOSES ONLY.

4. BASE STATION CONTROL DATA IS AVAILABLE UPON REQUEST.

COMMONWEALTH OF PENNSYLVANIA
REGISTERED PROFESSIONAL
JOSEPH JOHN HUNT
LAND SURVEYOR
No. SU075145

LINE	BEARING	DIST.
L1	N86°10'34" W	1669.60ft
L2	S77°32'13" W	1709.26ft
L3	N77°13'05" E	381.28ft
L4	N35°43'07" E	282±ft
L5	S74°51'27" E	311±ft

Surveyor or Engineer	Phone #	Dwg #	Date	Scale	Tract Acreage
JOSEPH J. HUNT, P.L.S., P.E.	610-858-6790	2008-CHK-003	11/25/2008 2/18/09	1" = 1,000'	190±

Lat & Long Metadata: Method GPSOF(L1,L2)RTK Accuracy 0.033' ft Datum NAD 83

Elevation Metadata: Method GPSOF(L1,L2)RTK Accuracy 0.069 ft. Datum NAVD '88 Survey Date 11/07/2008

Applicant / Well Operator Name: CHESAPEAKE APPALACHIA, L.L.C	DEP ID#: 246326	Well (Farm) Name: ROBSON	Well #: 1	Serial #:
Address: P.O. BOX 6070, CHARLESTON, WV 25362-0070		County: WAYNE	Municipality: OREGON TOWNSHIP	Well Type: NATURAL GAS
Surface Landowner / Lessor: ROBSON, BETTY ANN & CHRISTOPHER		USGS 7½' Quadrangle Map Name: GALILEE	Map Section: 8	Surface Elevation: 1493.3 ft.
Target Formation(s): ORISKANY		Angle & Course of Deviation (Drilling): 0°	Anticipated Total Depth ft.: TVD 8898	TMD

Surface Owner or Water Purveyor with a Water Supply within 1000 ft.	Approximate Course and Distance to Water Supply	Owner, Lessee, or Operator of Workable Coal Seam	Name of Coal Seam Owned, Leased, or Operated
DAVID S. & DIANE L. RICHTER	N36°15'35" E 402±ft		
JAMES II & BEVERLY LUDWIG	N69°54'35" E 777±ft		
ANTHONY J. & JUDITH NOVENA	S50°13'52" E 502±ft		

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DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL AND GAS MANAGEMENT PROGRAM

WELL LOCATION PLAT

DEP USE ONLY	
Auth ID #:	G:
Permit # 127-20008	
Project #:	C:

Well is located on topo map 14,207 feet south of latitude 41 ° 40 ' 00 "

12,050

Denotes location of well on topo map. SEE NOTE 1

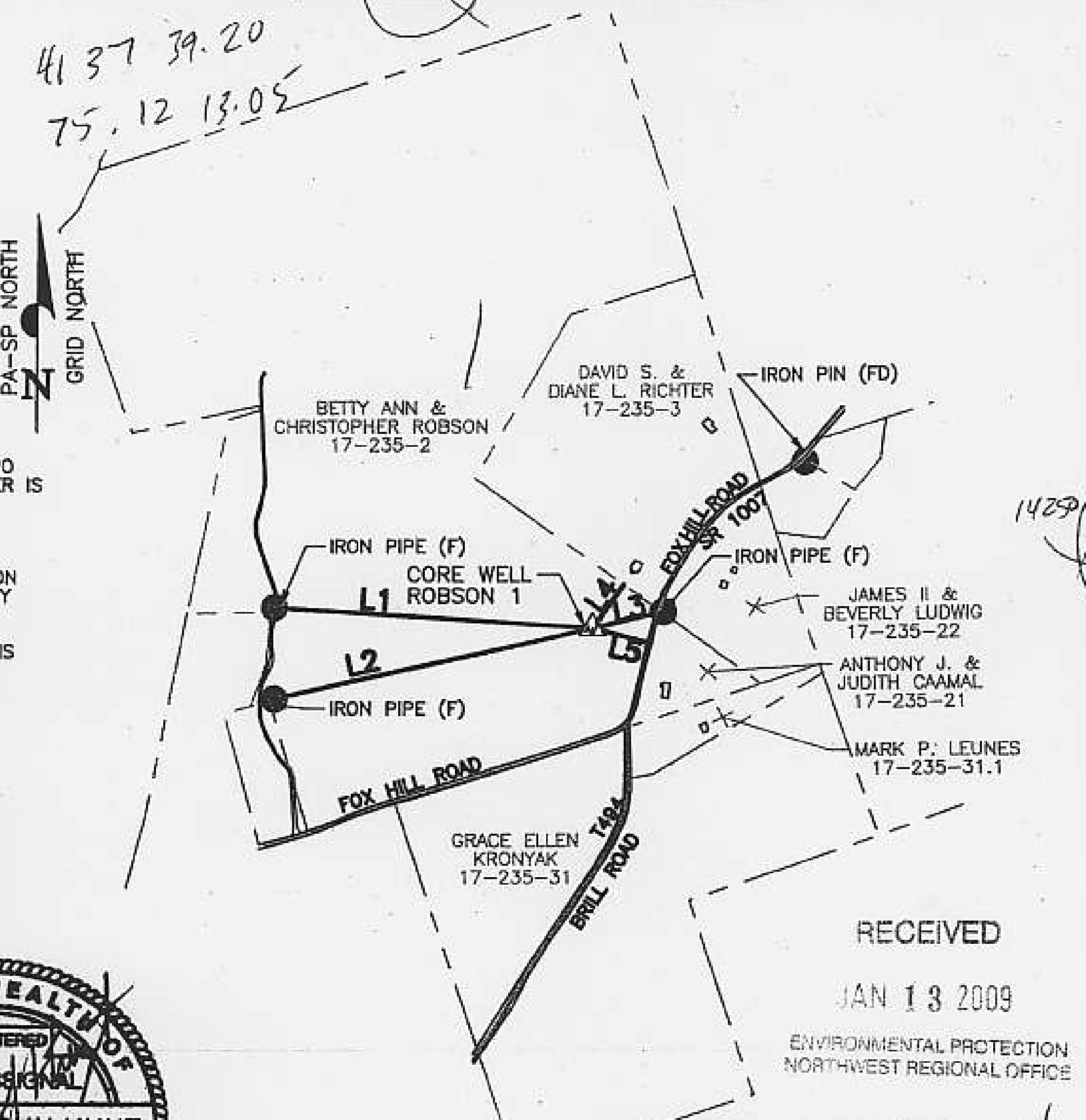
True Latitude: NORTH NAD 83
41 ° 37 ' 39.52 "

True Longitude: WEST
75 ° 12 ' 11.68 "

True Latitude: NORTH NAD 27
41.62756°

True Longitude: WEST
75.203625°

41 37 39.20
75 . 12 13.05



Well is located on topo map 1,838 feet west of longitude 75 ° 12 ' 30 "

1425

NOTES:

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REGISTERED PROFESSIONAL
JOSEPH JOHN HUNT
LAND SURVEYOR
No. SU075145

LINE	BEARING	DIST.
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L2	S77°32'13"W	1709.26ft
L3	N77°13'05"E	381.28ft
L4	N35°43'07"E	282± ft
L5	S74°51'27"E	311± ft

Surveyor or Engineer: JOSEPH J. HUNT, P.L.S., P.E.	Phone #: 610-858-6790	Dwg #: 2008-CHK-003	Date: 11/25/2008 REV. 5 12/16/2008	Scale: 1" = 1,000'	Tract Acreage: 190±

Lat & Long Metadata Method: GPSOF(L1,L2)RTK Accuracy 0.033' ft. Datum NAD 83		Elevation Metadata Method GPSOF(L1,L2)RTK Accuracy 0.069 ft. Datum NAVD '88		Survey Date 11/07/2008
Applicant / Well Operator Name: CHESAPEAKE APPALACHIA, L.L.C	DEP ID#: 246326	Well (Farm) Name: ROBSON (627528)	Well #: 1	Serial #:
Address: P.O. BOX 6070, CHARLESTON, WV 25362-0070		County: WAYNE	Municipality: OREGON TOWNSHIP	Well Type: NATURAL GAS
Surface Landowner / Lessor: ROBSON, BETTY ANN & CHRISTOPHER		USGS 7½' Quadrangle Map Name: GALILEE 0544	Map Section: 8	Surface Elevation: 1493.3 ±
Target Formation(s): ORISKANY		Angle & Course of Deviation (Drilling): 0°	Anticipated Total Depth ft. TVD	TMD

Surface Owner or Water Purveyor with a Water Supply within 1000 ft.	Approximate Course and Distance to Water Supply	Owner, Lessee, or Operator of Workable Coal Seam	Name of Coal Seam Owned, Leased, or Operated
DAVID S. & DIANE L. RICHTER	N36°15'35"E 402± ft		
JAMES II & BEVERLY LUDWIG	N69°54'35"E 777± ft		
ANTHONY J. & JUDITH CAAMAL	S50°13'52"E 502± ft		

NOVENA? on PG 2.

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DEPARTMENT OF ENVIRONMENTAL PROTECTION

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DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL AND GAS MANAGEMENT PROGRAM

WELL LOCATION PLAT

DEP USE ONLY	Auth ID #:	G:
	Permit # 127-20008	
	Project #:	C:

Denotes location of well on topo map. SEE NOTE 1

Well is located on topo map 14,207 (12,150) feet south of latitude 41° 40' 00"

Well is located on topo map 1,838 (1429) feet west of longitude 75° 12' 30"

41 37 39.20
75. 12 13.05

True Latitude: NORTH NAD 83	41° 37' 39.52"
True Longitude: WEST	75° 12' 11.68"
True Latitude: NORTH NAD 27	41.62756°
True Longitude: WEST	75.203625°

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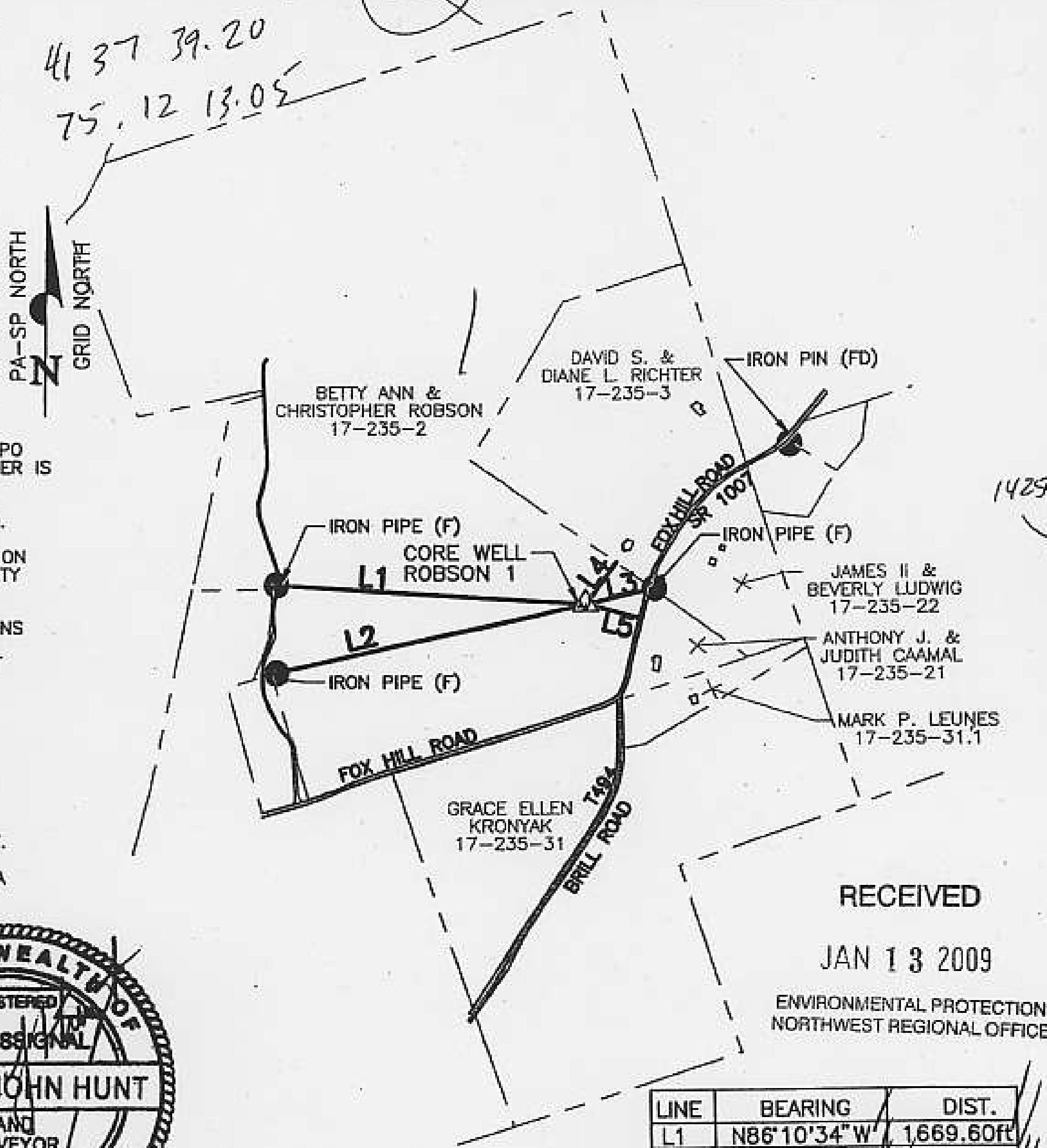

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REGISTERED PROFESSIONAL
JOSEPH JOHN HUNT
LAND SURVEYOR
No. SU075145

LINE	BEARING	DIST.
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L3	N77°13'05"E	381.28ft
L4	N35°43'07"E	282±ft
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Surveyor or Engineer	Phone #:	Dwg #:	Date:	Scale:	Tract Acreage:
JOSEPH J. HUNT, P.L.S., P.E.	610-858-6790	2008-CHK-003	11/25/2008 REV. 5 12/16/2008	1" = 1,000'	190±

Lat & Long Metadata		Elevation Metadata	
Method GPSOF(L1,L2)RTK Accuracy 0.033' ft. Datum NAD 83		Method GPSOF(L1,L2)RTK Accuracy 0.069 ft. Datum NAVD '88	Survey Date 11/07/2008
Applicant / Well Operator Name: CHESAPEAKE APPALACHIA, L.L.C	DEP ID#: 246326	Well (Farm) Name: ROBSON (627528) Well #: 1	Serial #:
Address: P.O. BOX 6070, CHARLESTON, WV 25362-0070		County: WAYNE; Municipality: OREGON TOWNSHIP	Well Type: NATURAL GAS
Surface Landowner / Lessor: ROBSON, BETTY ANN & CHRISTOPHER		USGS 7½' Quadrangle Map Name: GALILEE 0544; Map Section: 8	Surface Elevation: 1493.3 ft
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ANTHONY J. & JUDITH CAAMAL	S50°13'52"E 502±ft		

NOVENA? on DG 2.

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COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL AND GAS MANAGEMENT PROGRAM

WELL LOCATION PLAT

(Attachment, if needed)

DEP USE ONLY	Auth ID #: 127-20028

Use only if you need additional space for listings.

Applicant / Well Operator Name	DEP ID#	Well (Farm) Name	Well #	Serial #
CHESAPEAKE APPALACHIA, L.L.C	246326	ROBSON	1	

Surface Owner or Water Purveyor with a Water Supply within 1000 feet	Approximate Course and Distance to Water Supply	Owner, Lessee, or Operator of Workable Coal Seam	Name of Coal Seam Owned, Leased or Operated
MARK P. LEUNES	S48°12'41"E 790±ft		

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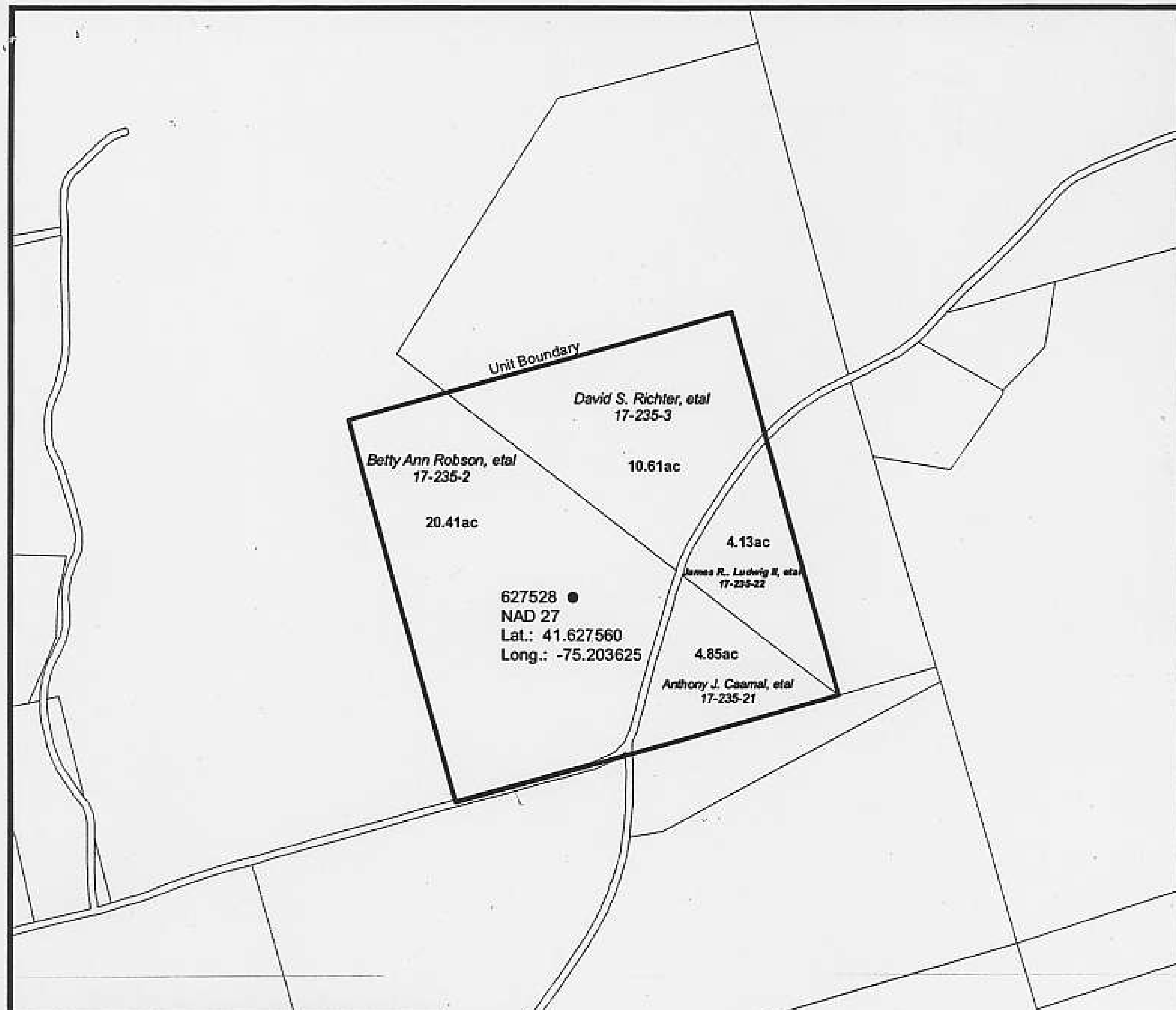
NORTHWEST REGIONAL OFFICE



NOTICE

This map/plat reflects only the approximate location of the depicted natural gas facilities (including property lines, lease and lease boundary lines). Neither Chesapeake Appalachia, L.L.C. nor any of its employers or contractors make any warranty, expressed or implied with respect to the accuracy or completeness of the document.

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Call or Write:

Manager, Technical Services
Chesapeake Appalachia, L.L.C. P.O. Box 6070
Charleston, WV 25362-6070
(304) 353-5000

THIS MAP MAY NOT REFLECT TRACTS LESS THAN 10 ACRES

UNIT EXHIBIT

WELL 627528 (Robson 1)
Oregon Twp., Wayne Co., PA

1 inch = 500 feet

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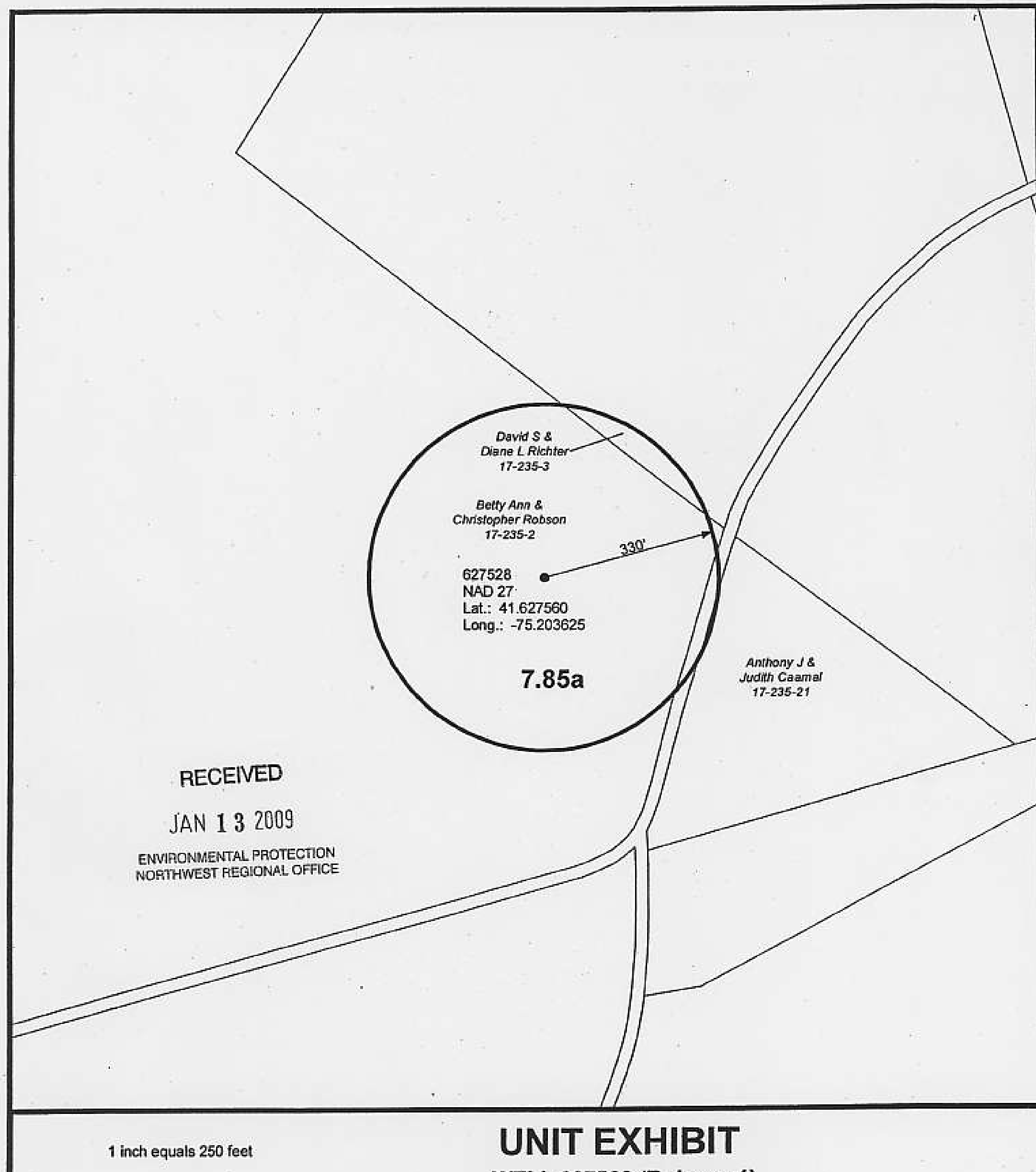
Chesapeake ENERGY

● CHK Well Location 627528

▭ Robson 1 Unit - 40.00ac

Printing Date: January 7, 2009 W:\Unit Exhibits\2009\PA\627528 ROBSON 1-RMS\627528_Robson1.mxd



UNIT EXHIBIT

WELL 627528 (Robson 1)
Oregon Twp., Wayne Co., PA

1 inch equals 250 feet

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Chesapeake Appalachia, L.L.C. expressly disclaims responsibility for any action, activity, or decision by a third party on the basis of the information depicted on this map/plat.
Call or Write:

Manager, Technical Services
Chesapeake Appalachia, L.L.C. P.O. Box 6070
Charleston, WV 25362-0070
(304) 353-5000

THIS MAP MAY NOT REFLECT TRACTS LESS THAN 10 ACRES

● CHK Well Location

▭ Robson 1 Unit - 7.85a

Chesapeake ENERGY

Printing Date: January 7, 2009 - File: W:\Unit Exhibits\2009\PA\627528 ROBSON 1-RMS\627528_Robson1_330.mxd

Tim Smith
Manager – Regulatory
Northern Districts
Office: (304) 353-5065
Cell: (304) 382-8783
tim.smith@chk.com

January 9, 2009

Mr. Robert Gleeson
Commonwealth of Pennsylvania
Department of Environmental Protection
Oil and Gas Management Program
230 Chestnut Street
Meadville, PA 16335-3481

Re: Robson 1 (627528) - Permit Application for Drilling a Well
Wayne County, Oregon Township

Dear Mr. Gleeson:

Chesapeake Appalachia, L.L.C. submits the enclosed *Permit Application for Drilling or Altering a Well* for its proposed Robson 1 (627528) well located in Wayne County, Oregon Township.

If you should have any questions or require additional information, please do not hesitate to contact me.

Sincerely,

Chesapeake Appalachia, L.L.C.

Tim Smith

Tim Smith

Enclosures

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ENVIRONMENTAL PROTECTION
NORTHWEST REGIONAL OFFICE

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Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

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Sent To
Street, Apt. No.; or PO Box No.
City, State, ZIP+4

Mr and Mrs. Anthony J Novena
404 Fox Hill Road
Honesdale PA 18431

PS Form 3800, A

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
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1. Article Addressed to:

Mr and Mrs. Anthony J Novena
404 Fox Hill Road
Honesdale PA 18431

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X J Novena
☐ Agent
☐ Addressee

B. Received by (Printed Name)
Anthony Novena

C. Date of Delivery

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

HONESDALE
DEC 05 2008
USPS

3. Service Type
☐ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7008 0150 0001 4928 0290

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Total Postage & Fees	$

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Sent To: Mr. Mark P. Leunes
Street, Apt. No. or PO Box No.: 240 Brill Rd
City, State, ZIP: Honesdale, PA 18431

PS Form 3800

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. Mark P. Leunes
240 Brill Rd
Honesdale, PA 18431

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X Michelle Ryan ☐ Agent ☐ Addressee

B. Received by (Printed Name) Michelle Renir C. Date of Delivery

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☐ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7008 0150 0001 4928 0320

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-15

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NORTHWEST REGIONAL OFFICE

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JAN 1 3 2009
ENVIRONMENTAL PROTECTION
NORTHWEST REGIONAL OFFICE

CONSOLIDATION OF LEASE
Robson 1 Unit

KNOW ALL MEN BY THESE PRESENTS that the undersigned, Chesapeake Appalachia, L.L.C., with its principal place of business at P. O. Box 6070, 900 Pennsylvania Avenue, Charleston, WV 25362-0070, owner and holder as Lessee of the oil and gas leases described herein, does hereby select to consolidate the lands shown on the attached plat and covered by each of said leases set forth, to form an oil and gas development unit of forty and No/100 (40.00) acres, more or less, for a well or wells located upon the lands of any of the leases hereinafter described, which leases cover land in Oregon Township, Wayne County, Pennsylvania, incorporated herein by reference as follows:

LESSOR	DATE	RECORDED	ACRES	ACRES IN UNIT
Betty Ann Theobald & Christopher D. Robson	05/18/08	DBV 3547/310	175.21	20.51/40.00
David S. Richter & Diane L. Richter	06/27/08	DBV 3574/199	34.00	10.61/40.00
James R. Ludwig, II & Beverly A. Ludwig	05/03/08	DBV 3550/62	13.00	4.13/40.00
Anthony J Novena & Judith C. Novena aka Judith Caamal	01/23/09		4.85	4.85/40.00

In accordance with the terms and conditions of each of such leases, such one-eighth (1/8) royalty as therein provided shall be payable to and in the following proportions:

NAME	ADDRESS	ROYALTY
Betty Ann Theobald & Christopher D. Robson	45 Ripple Lane, Honesdale, PA 18431-7852	20.51/40.00
David S. Richter & Diane L. Richter	455 Fox Hill Road, Honesdale, PA 18431-7848	10.61/40.00
James R. Ludwig, II & Beverly A. Ludwig	434 Fox Hill Road, Honesdale, PA 18431-7848	4.13/40.00
Anthony J Novena & Judith C. Novena aka Judith Caamal	404 Fox Hill Road, Honesdale, PA 18431-7848	4.85/40.00

Under the terms and conditions of each such lease as herein consolidated, the lands covered hereby shall be consolidated as a single tract of land for the purpose of drilling, and a well commenced upon any of the lands herein consolidated shall have the same effect as though such well were commenced upon the premises described in each such oil and gas lease, provided that only the owner of the lands on which such well is located shall have the privilege of taking gas for use on said lands in accordance with and subject to the provisions of the lease covering said land.

IN WITNESS WHEREOF, we sign this 30th day of January, 2009.

WITNESS
Georgene Bradley

CHESAPEAKE APPLACHIA, L.L.C.

By: Marty Byrd
Marty Byrd
Its: Vice President Land – Eastern Division

gmw

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FEB 0 5 2009

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NORTHWEST REGIONAL OFFICE

STATE OF WEST VIRGINIA)
) SS
COUNTY OF KANAWHA)

On this the 30th day of January, 2009, before me, a Notary Public, the undersigned officer, personally appeared Marty Byrd, who acknowledged himself to be the Vice President Land – Eastern Division of Chesapeake Appalachia, L.L.C., a Limited Liability Corporation, and that as such, being authorized to do so, executed the foregoing instrument for the purposes therein contained by signing the name of said Limited Liability Corporation to himself as Vice President Land – Eastern Division.

IN WITNESS WHEREOF, I hereunto set my hand and official seal.

Brenda J. Flesher
Notary Public

My Commission Expires: February 7, 2011

OFFICIAL SEAL
NOTARY PUBLIC
STATE OF WEST VIRGINIA
BRENDA J. FLESHER
P. O. Box 585
Pinch, WV 25156
My Commission Expires Feb. 7, 2011

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Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

BIG FLATS NY
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Sent To
Mr. and Mrs. James Ludwig II
Street, Apt. No.; or PO Box No.
434 Fox Hill Road
City, State, ZIP+4
Honesdale, PA 18431

PS Form 3800, A

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Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

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7008 0150 0001 4928 0313

Sent To
Mr. and Mrs. David S. Richter
Street, Apt. No.; or PO Box No.
455 Fox Hill Road
City, State, ZIP+4
Honesdale, PA 18431

PS Form 3800

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. and Mrs. David S. Richter
455 Fox Hill Road
Honesdale, PA 18431

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X Keith Richter ☐ Agent ☐ Addressee

B. Received by (Printed Name) | C. Date of Delivery

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

HONESDALE PA 18431 DEC 04 2008 USPS

3. Service Type
☐ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number
(Transfer from service label) 7008 0150 0001 4928 0313

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-1540

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Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postag	$

BIG FLATS NY
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DEC 0 2 2008
USPS - 14

Sent To
Street, Apt. N
or PO Box N
City, State, Z

Mr. and Mrs. Christopher Robson
45 Ripple Lane
Honesdale, PA 18431

PS Form 3800, August 20

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Mr. and Mrs. Christopher Robson
45 Ripple Lane
Honesdale, PA 18431

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X [signature]
☐ Agent
☐ Addressee

B. Received by (Printed Name) Chris Robson
C. Date of Delivery 12/5/08

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☐ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 7008 0150 0001 4928 2362

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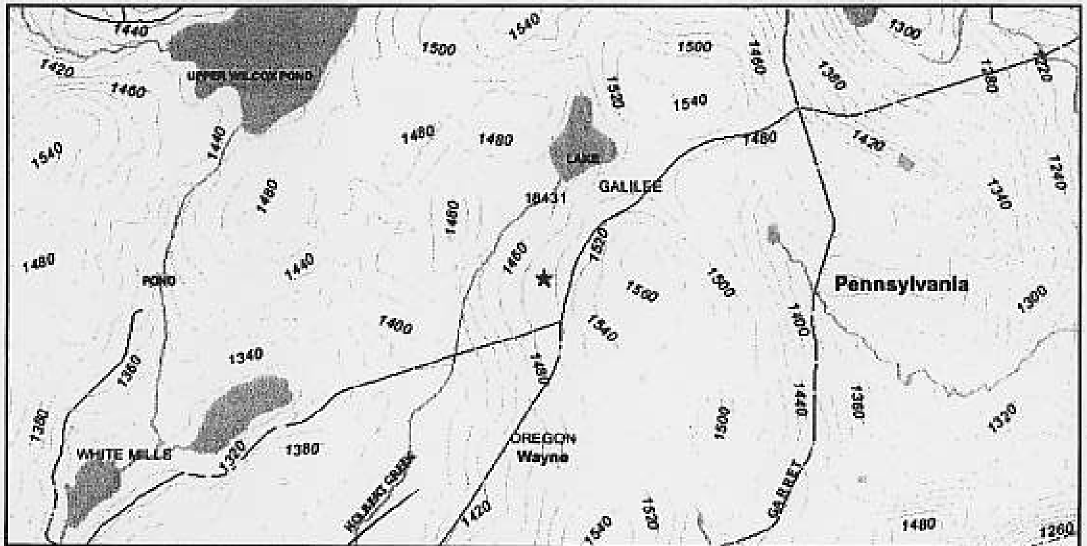
PNDI Project Environmental Review Receipt
Project Search ID: 20081204169530
Project Name: ROBSON 1
Date: 12/4/2008 9:06:10 AM

Project Location



Project Name: ROBSON 1
On Behalf Of: Self
Project Search ID: 20081204169530
Date: 12/4/2008 9:06:02 AM
# of Potential Impacts: 0
Jurisdictional Agency:
Project Category: Energy Storage, Production, and Transfer,Energy Production (generation),Oil or Gas - new wells, expansion of well field
Project Location
Decimal Degrees: 41.627644 N, -75.203244 W
Degrees Minutes Seconds: 41° 37' 39.52" N, 75° 12' 11.68" W
Lambert: 764519.15554522, 969550.47783612 ft
ZIP Code: 18431
County: Wayne
Township/Municipality: OREGON
USGS 7.5 Minute Quadrangle ID: 138
Quadrangle Name: GALILEE
Project Area: N/A

Location Accuracy

Project locations are assumed to be both precise and accurate for the purposes of environmental review. The creator/owner of the Project Review Receipt is solely responsible for the project location and thus the correctness of the Project Review Receipt content.

0 Known Impacts

Under the Following Agencies' Jurisdiction:
None

APPLICANT INITIALS: RAK

PNDI Project Environmental Review Receipt

Project Search ID: 20081204169530
Project Name: ROBSON 1
Date: 12/4/2008 9:06:10 AM

Pennsylvania Natural Diversity Inventory (PNDI) records do **NOT** indicate any known impacts on special concern species and resources within the project area. DEP requires a signed copy of this receipt with permit applications being submitted as indication that an environmental review has been conducted and completed. See DEP PNDI policy at www.naturalheritage.state.pa.us for more information.

Based on the information you provided, no further coordination is required by the Pennsylvania Game Commission, the Pennsylvania Fish and Boat Commission, or the Pennsylvania Department of Conservation and Natural Resources with regard to special concern species, natural communities, or outstanding geologic features. This response does not reflect potential agency concerns regarding impacts to other ecological resources, such as wetlands.

Based on the project-specific information you provided, no impacts to federally listed, proposed, or candidate species are anticipated. Therefore, no further consultation under the Endangered Species Act (87 Stat. 884, as amended; 16 U.S.C. 1531 *et seq.* is required with the U.S. Fish and Wildlife Service. Because no take of federally listed species is anticipated, none is authorized. For a list of species that could occur in your project area (but have not been documented in PNDI), please see the county lists of threatened, endangered, and candidate species. A field visit or survey may reveal previously undocumented populations of one or more threatened or endangered species with a project area. If it is determined that any federally listed species occur in your project area, the U.S. Fish and Wildlife Service requires that you initiate consultation to identify and resolve any conflicts. This response does not reflect potential Fish and Wildlife Service concerns under the Fish and Wildlife Coordination Act or other authorities.

These determinations were based on the project-specific information you provided, including the exact project location; the project type, description, and features; and any responses to questions that were generated during this search. If any of the information you provided does not accurately reflect this project, or if project plans change, DEP and the jurisdictional agencies require that another PNDI review be conducted.

This response represents the most up-to-date summary of the PNDI data files and is <u>good for one(1) year</u> from the date of this PNDI Project Environmental Review Receipt.

DISCLAIMER

The PNDI environmental review website is a preliminary environmental screening tool. It is <u>not</u> a substitute for information obtained from a field survey of the project area conducted by a biologist. Such surveys may reveal previously undocumented populations of species of special concern. In addition, the PNDI only contains information about species occurrences that have actually been <u>reported</u> to the Pennsylvania Natural Heritage Program.

TERMS OF USE

Upon signing into the PNDI environmental review website, and as a condition of using it, you agreed to certain terms of use. These are as follows:

The web site is intended solely for the purpose of screening projects for potential impacts on resources of special concern in accordance with the instructions provided on the web site. Use of the web site for any other purpose or in any other way is prohibited and subject to criminal prosecution under federal and state law, including but not limited to the following: Computer Fraud and Abuse Act of 1986, as amended, 18 U.S.C. Â§ 1030; Pennsylvania Crimes Code, Â§ 4911 (tampering with public records or information), Â§ 7611 (unlawful use of computer and other computer crimes), Â§ 7612 (disruption of service), Â§ 7613 (computer theft), Â§ 7614 (unlawful duplication), and Â§ 7615 (computer trespass).

APPLICANT INITIALS: PAK

PNDI Project Environmental Review Receipt

Project Search ID: 20081204169530
Project Name: ROBSON 1
Date: 12/4/2008 9:06:10 AM

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The PNHP reserves the right at any time and without notice to modify or suspend the web site and to terminate or restrict access to it.

The terms of use may be revised from time to time. By continuing to use the web site after changes to the terms have been posted, the user has agreed to accept such changes.

This review is based on the project information that was entered. The jurisdictional agencies and DEP require that the review be redone if the project area, location, or the type of project changes. If additional information on species of special concern becomes available, this review may be reconsidered by the jurisdictional agency.

PRIVACY and SECURITY

This web site operates on a Commonwealth of Pennsylvania computer system. It maintains a record of each environmental review search result as well as contact information for the project applicant. These records are maintained for internal tracking purposes. Information collected in this application will be made available only to the jurisdictional agencies and to the Department of Environmental Protection, except if required for law enforcement purposesâ€"see paragraph below.

This system is monitored to ensure proper operation, to verify the functioning of applicable security features, and for other like purposes. Anyone using this system consents to such monitoring and is advised that if such monitoring reveals evidence of possible criminal activity, system personnel may provide the evidence to law enforcement officials. See Terms of Use.
Print this Project Review Receipt using your Internet browser's print function and keep it as a record of your search.

Signature: Rachelle A King

Date: 1/8/08

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Project applicant on whose behalf this search was conducted:

APPLICANT

Contact Name: Chesapeake Appalachia LLC

Address: 900 Pennsylvania Ave

City, State, Zip: Charleston, WV 25302

Phone: (304) 391-5588

Email: rachelle.king@chk.com

PERSON CONDUCTING SEARCH (if not applicant)

Contact Name: ______

Address: ______

City, State, Zip: ______

Phone: ______

Email: ______

The following contact information is for the agencies involved in this Pennsylvania Natural Diversity Inventory environmental review process. Please read this entire receipt carefully as it contains instructions for how to contact these agencies for further review of this particular project.

APPLICANT INITIALS: RAK

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NORTHWEST REGIONAL OFFICE

APPLICANT INITIALS: RAK

Pennsylvania Department of Environmental Protection

230 Chestnut Street
Meadville, PA 16335-3481

January 21, 2009

Northwest Regional Office

814-332-6869
Fax: 814-332-6121

TIM - [redacted]

37-015 - 20172

Tim Smith
Manager – Regulatory, Northern Districts
Chesapeake Energy Corporation – Eastern Division
P.O. Box 6070
Charleston, WV 25362-0070

- CALL 1/26/09 LEFT MESSAGE ABOUT UNITIZATION - NEED TO BREAK OUT AREA.

Re: Technical Deficiency Letter
Chesapeake Energy Corporation
Robson 1 – Permit Application for Drilling a Well
Wayne County, Oregon Township

Dear Mr. Smith:

The Department has reviewed your application and has determined that the following significant deficiencies exist:

Plat problems

Plats are to be accurately prepared as required by the Oil and Gas Act-section 201(b) and Title 25-Chapter 78.15(b) of the PA Code.

Latitude-Longitude, topo mark and topo mark offsets do not correspond to the same location. Additionally, no "anticipated total depth" figure has been provided.

Page 2 & plat differ

The plat submitted with application does not correspond with the information provided on Page 2 of the application. Permit applications are to be accurately prepared as required by the Oil and Gas Act-section 201(b) and Title 25-Chapter 78.15(b) of the PA Code.

Plat indicates Anthony J. & Judith Caamal as surface owners with water supply, Page 2 and associated notifications indicate Anthony J. & Judith Novena as surface owners with water supply.

Unit Agreement

The application plat shows the intended well site to be within 330' of a property line boundary for a neighboring land parcel.

Wells that are subject to the Oil and Gas Conservation Law need be located at least 330 feet from the outside lease or unit boundary as required by the Oil and Gas Conservation Law-section 6(a) and Title 25-Chapter 79.11(b) of the PA Code.

Provided Affidavit of Unitization does not declare a unit, nor does it define the distribution of the unit for those individuals included in the unit. Affidavit of Unitization text defines a 660' x 660' square foot area (resulting in a 10 acre area), Permit application exhibit shows a 660' diameter area (resulting in a 7.85 acre area). Please review attached example of a unit agreement.

See attached Notice of Incomplete Application for these significant deficiencies and other deficiencies if they have been identified.

Should you have any questions regarding the identified deficiencies, please contact me to discuss your concerns or to schedule a meeting. The meeting must be scheduled within the sixty (60) day period allotted for your reply, unless otherwise extended by the Department. Upon receipt of your submission the department will continue its evaluation of your application. You will be notified later if deficiencies remain in your application. You will have a final opportunity to correct any deficiencies, which will be in a pre-denial letter, before the Department makes a final determination. In accordance with the department's Money Back Guarantee Program, the clock tracking the elapsed time for review of your application has stopped while you prepare a response to this letter. The clock will start again when you provide the requested information.

If you believe the stated deficiencies are not significant, you have the option of declining and asking the Department to make a decision based on the information you have already made available.

If you choose this option, you should explain and justify how your current submission satisfies the deficiencies noted above. Please keep in mind that if you ignore this request or fail to respond by March, 22, 2009, you're application will be denied.

If you have any questions concerning this matter, please contact our office.

Sincerely,

Joseph F. Lichtinger, P.G.
Oil and Gas Management

Chesapeake ENERGY

Tim Smith
Manager – Regulatory
Northern Districts
Office: (304) 353-5065
Cell: (304) 382-8783
tim.smith@chk.com

February 3, 2009

UPS OVERNIGHT MAIL

Mr. Joseph F. Lichtinger, P.G.
Pennsylvania Department of Environmental Protection
Oil and Gas Management Program
230 Chestnut Street
Meadville, PA 16335-3481

Re: Deficiency Response for Robson 1 (627528) Well Permit Application

Dear Mr. Lichtinger:

Please find enclosed the corrections that have been made to the above-mentioned well permit application that was returned to Chesapeake due to the deficiencies found within this application as indicated below:

1. Plat – Latitude & Longitude, the topographic mark and the offsets have been corrected to correspond that the location is the same. Also, the anticipated total depth has been included on the corrected plat.
2. Page 2 & Plat Differ – The name that is shown on Page 2 is the correct name of the surface landowner with a water supply, Anthony J. & Judith Novena. The well plat has been corrected to show the correct name so it corresponds with Page 2 of the Permit Application.
3. Unit Agreement – The well site is within 330 feet of a property boundary for a neighboring land parcel and subject to the Oil and Gas Conservation Law. A corrected Unit Exhibit and Affidavit of Unitization have been included to provide the Department what is required.

If you should have any questions or require additional information, please do not hesitate to contact me.

Sincerely,

Chesapeake Appalachia, L.L.C.

Tim Smith

Tim Smith
Enclosures

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NORTHWEST REGIONAL OFFICE

Phone Contact Log

Date: 2/9/09 **Tracking Number:** 127- 20008

Time: 9:25 **Farm Name:** ROBSON

Number Called: 304-353-3065 **Well Number:** 1

Company Called: CHESAPEAKE

Person Contacted: TIM SMITH

Deficiencies Addressed:

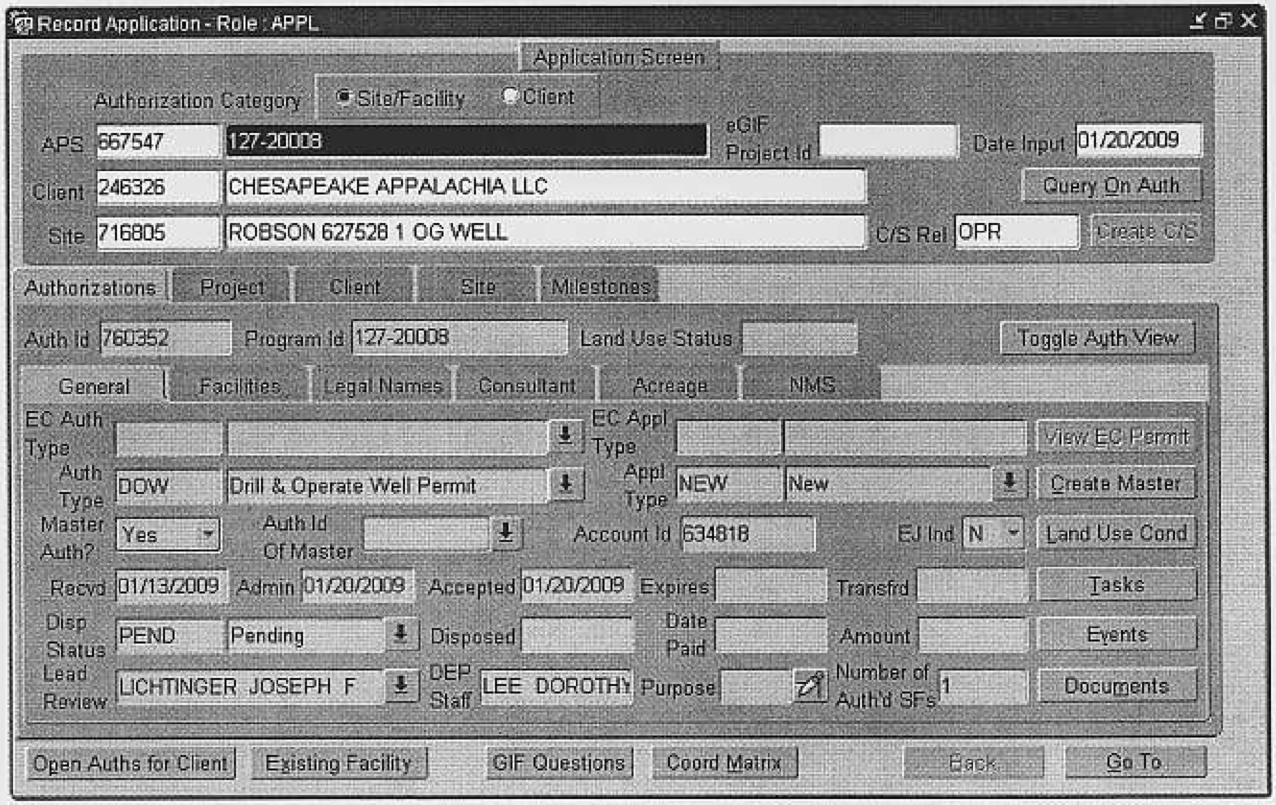
1. TOPO MARK @ INCORRECT LOCATION

REPLY - LEFT MESSAGE.

CALLED AGAIN 2/11/09 ON CELL - LEFT MESSAGE

2/17/09 CALLED SURVEYOR. HE WILL SEND NEW ONES.

Denial Date:



Record Application - Role : APPL
Application Screen
Authorization Category
Site/Facility
Client
APS 667547
127-20008
eGIF Project Id
Date Input 01/20/2009
Client 246326
CHESAPEAKE APPALACHIA LLC
Query On Auth
Site 716805
ROBSON 627528 1 OG WELL
C/S Rel OPR
Create C/S
Authorizations
Project
Client
Site
Milestones
Auth Id 760352
Program Id 127-20008
Land Use Status
Toggle Auth View
General
Facilities
Legal Names
Consultant
Acreage
NMS
EC Auth Type
EC Appl Type
View EC Permit
Auth Type DOW
Drill & Operate Well Permit
Appl Type NEW
New
Create Master
Master Auth? Yes
Auth Id Of Master
Account Id 634818
EJ Ind N
Land Use Cond
Recvd 01/13/2009
Admin 01/20/2009
Accepted 01/20/2009
Expires
Transfrd
Tasks
Disp Status PEND
Pending
Disposed
Date Paid
Amount
Events
Lead Review LICHTINGER JOSEPH F
DEP Staff LEE DOROTHY
Purpose
Number of Auth'd SFs 1
Documents
Open Auths for Client
Existing Facility
GIF Questions
Coord Matrix
Back
Go To

Manage Tasks By Auth - Role : APPL

Authorizations

Auth Id	760352	Money Back?	Y	MBG Status	ACTIVE		
APS Id	667547	Entity Name	ROBSON 627528 1				
Auth Type	DOW	Drill & Operate Well Permit					
Appl Type	NEW	New		Date Disposed		Disposition Status	PEND
Date Paid		Fee Amount		Date Returned		Fee Returned	
STD Days	45	Days Left	37	Current Status	OFF THE CLOCK	Date Went Overdue	
Lead Reviewer	440398	LICHTINGER JOSEPH F				Date Received	01/13/2009

Authorization Standard Tasks

Code	Description	Begin Date	Due Date	End Date	Comment
ADMRV	Begin/End Administrative Review	01/13/2009	01/18/2009	01/20/2009	Chesapeake Appalachia LLC
TECH1	Begin/End Technical Review 1	01/21/2009	03/02/2009		
TECH2	Begin/End Technical Review 2				
DECRV	Begin/End Decision Review				

Authorization Sub Tasks

Code	Description	Begin Date	Due Date	End Date	Name	Comment
CL	Send Deficiency Notice/Recei	01/21/2009	03/21/2009		LICHTINC	Sent Def Letter - Plat, F
GR	B/E App Geologic Review	01/21/2009	02/15/2009		LICHTINC	
PC	Complete PNDI Check	01/21/2009	01/21/2009		LICHTINC	

Manage Tasks By Auth - Role : APPL

Authorizations

Auth Id 760352 Money Back? Y MBG Status ACTIVE

APS Id 667547 Entity Name ROBSON 627528 1

Auth Type DOW Drill & Operate Well Permit

Appl Type NEW New Date Disposed Disposition Status PEND

Date Paid Fee Amount Date Returned Fee Returned

STD Days 45 Days Left 37 Current Status OFF THE CLOCK Date Went Overdue

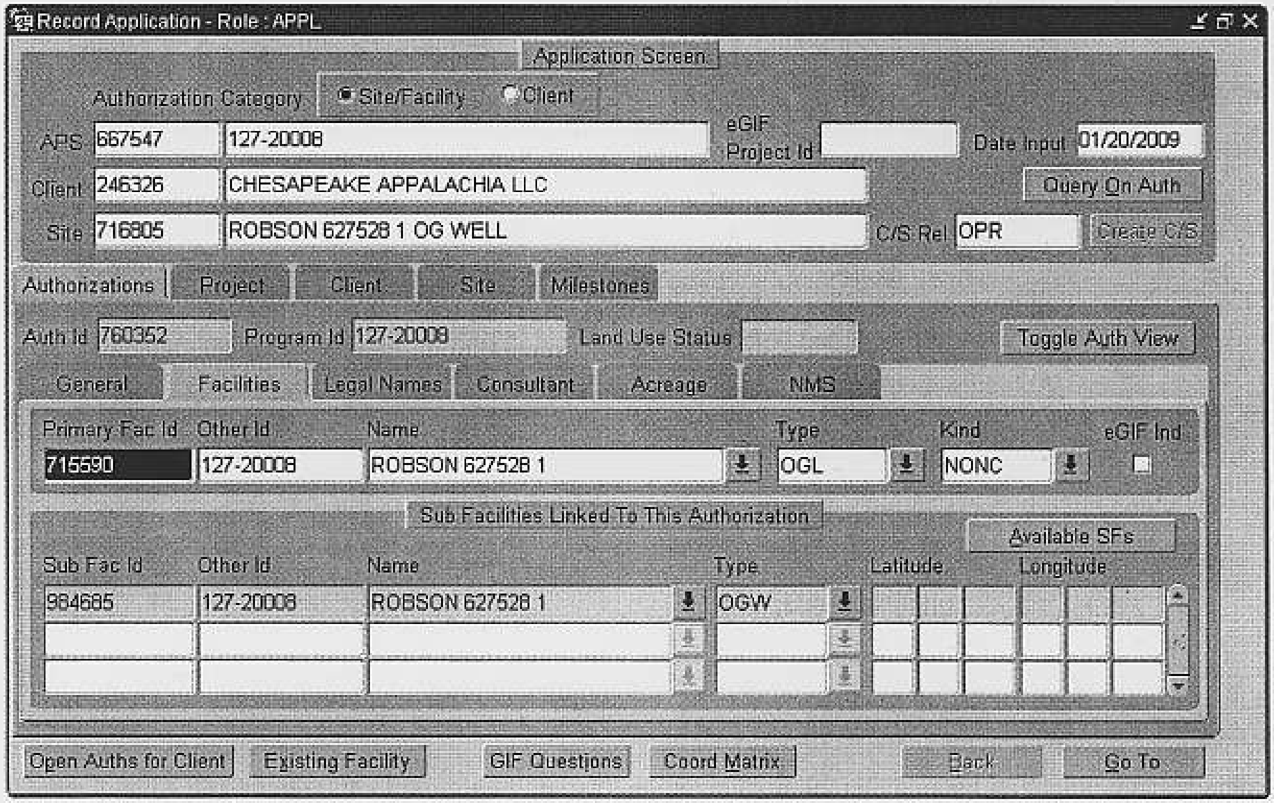
Lead Reviewer 440398 LICHTINGER JOSEPH F Date Received 01/13/2009

Authorization Standard Tasks

Code	Description	Begin Date	Due Date	End Date	Comment
ADMRV	Begin/End Administrative Review	01/13/2009	01/18/2009	01/20/2009	Chesapeake Appalachia LLC
TECH1	Begin/End Technical Review 1	01/21/2009	03/02/2009		
TECH2	Begin/End Technical Review 2				
DECRV	Begin/End Decision Review				

Authorization Sub Tasks

Code	Description	Begin Date	Due Date	End Date	Name	Comment
AC	B/E Appl Complete Review	01/13/2009	01/18/2009	01/20/2009	LEE	



Record Application - Role : APPL

Application Screen

Authorization Category: (•) Site/Facility ( ) Client

APS	667547	127-20008	eGIF Project Id		Date Input 01/20/2009
Client	246326	CHESAPEAKE APPALACHIA LLC			Query On Auth
Site	716805	ROBSON 627528 1 OG WELL	C/S Rel	OPR	Create C/S

Authorizations | Project | Client | Site | Milestones

Auth Id 760352 | Program Id 127-20008 | Land Use Status | Toggle Auth View

General | Facilities | Legal Names | Consultant | Acreage | NMS

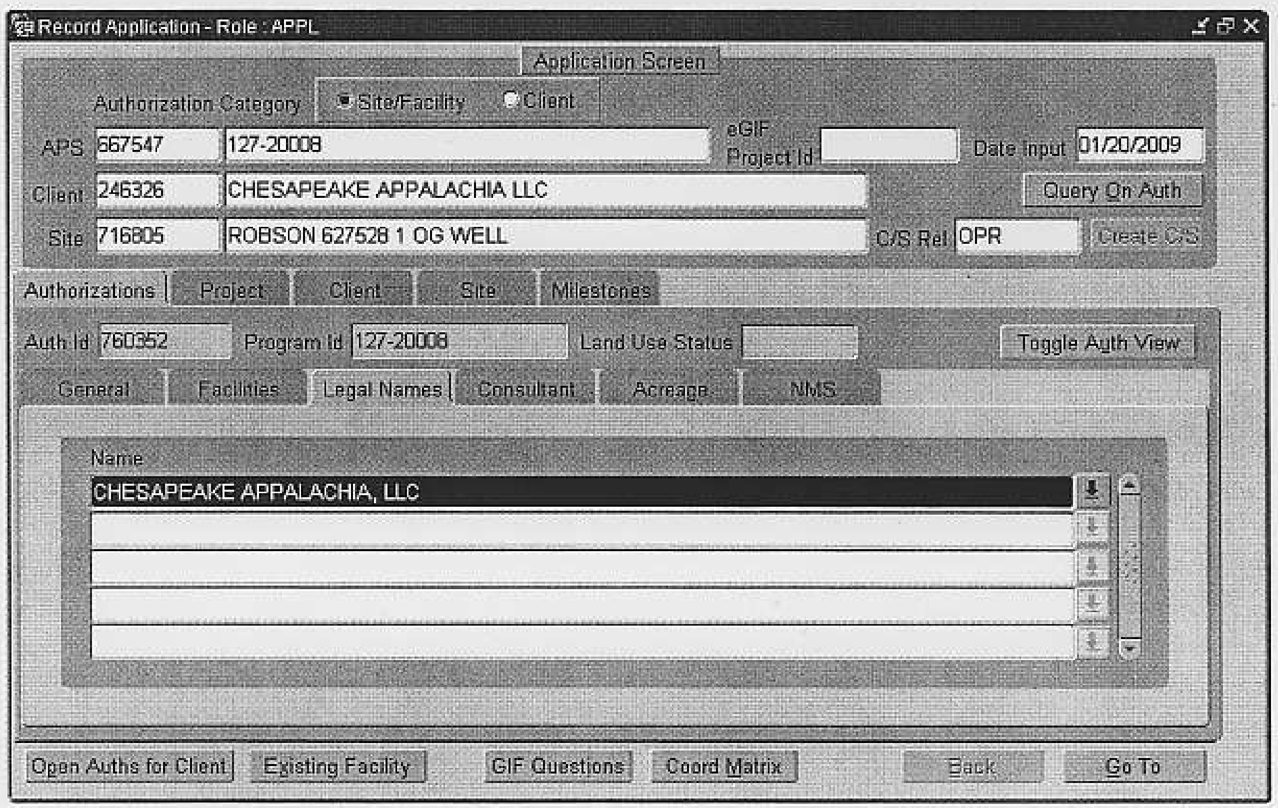
Primary Fac Id	Other Id	Name	Type	Kind	eGIF Ind
715590	127-20008	ROBSON 627528 1	OGL	NONC	

Sub Facilities Linked To This Authorization

Available SFs

Sub Fac Id	Other Id	Name	Type	Latitude	Longitude
984685	127-20008	ROBSON 627528 1	OGW		

Open Auths for Client | Existing Facility | GIF Questions | Coord Matrix | Back | Go To


Record Application - Role : APPL

Application Screen

Authorization Category ◉ Site/Facility ○ Client

APS 667547 127-20008 eGIF Project Id Date input 01/20/2009

Client 246326 CHESAPEAKE APPALACHIA LLC Query On Auth

Site 716805 ROBSON 627528 1 OG WELL C/S Rel OPR Create C/S

Authorizations | Project | Client | Site | Milestones

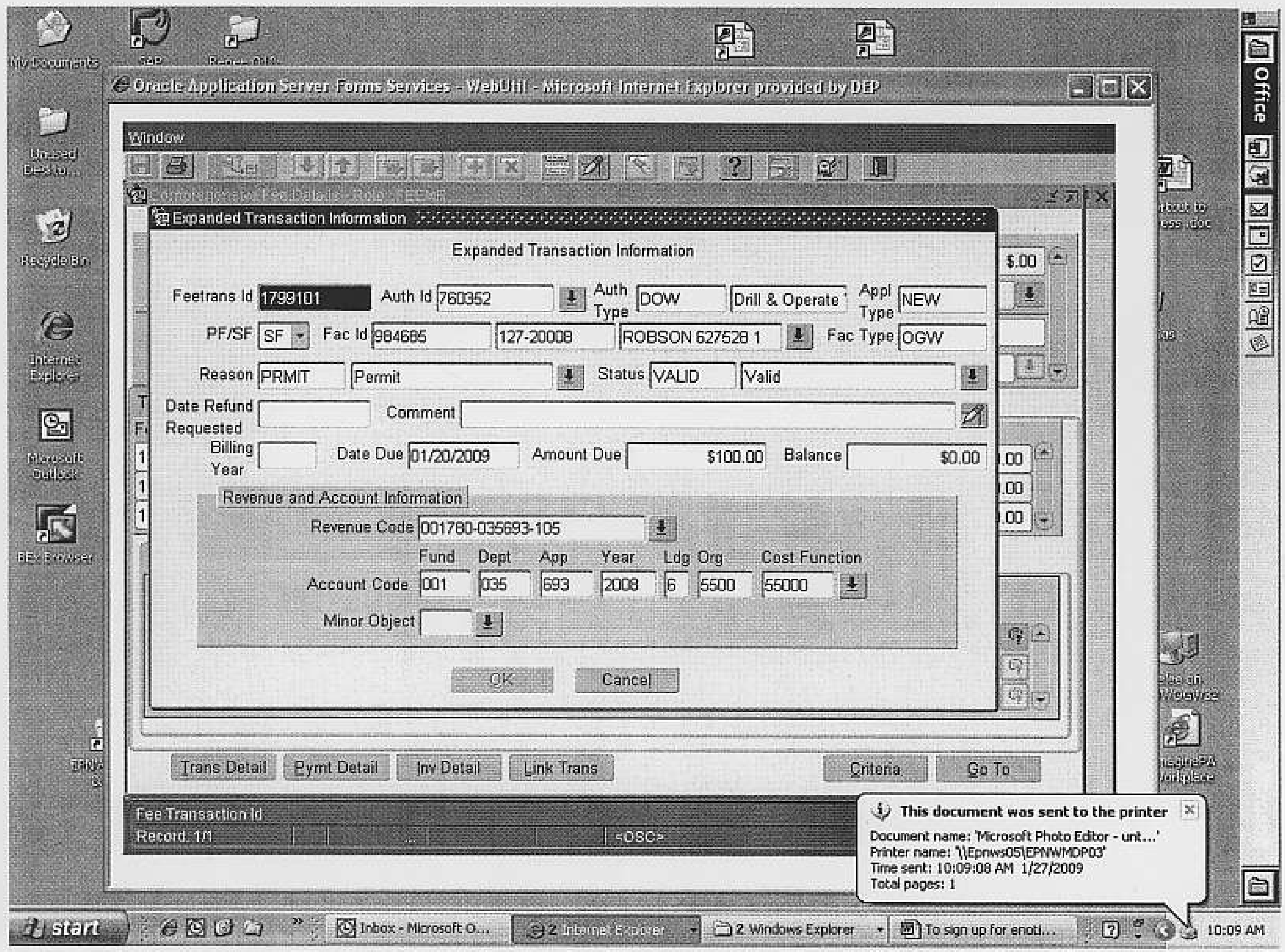
Auth Id 760352 Program Id 127-20008 Land Use Status Toggle Auth View

General | Facilities | Legal Names | Consultant | Acreage | NMS

Name

CHESAPEAKE APPALACHIA, LLC

Open Auths for Client | Existing Facility | GIF Questions | Coord Matrix | Back | Go To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127-20008
ROBSON 627528 1
Fac Type OGW
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Date Refund Requested
Comment
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Date Due 01/20/2009
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Account Details

Accounts

Account Id	Category	Category Id	Acct Balance
634818	MAUTH	760352	$.00

Client			Program	Region
246326		CHESAPEAKE A	OG	4600

Account Id | Category | Category Id | Acct Balance

Client | Program | Region

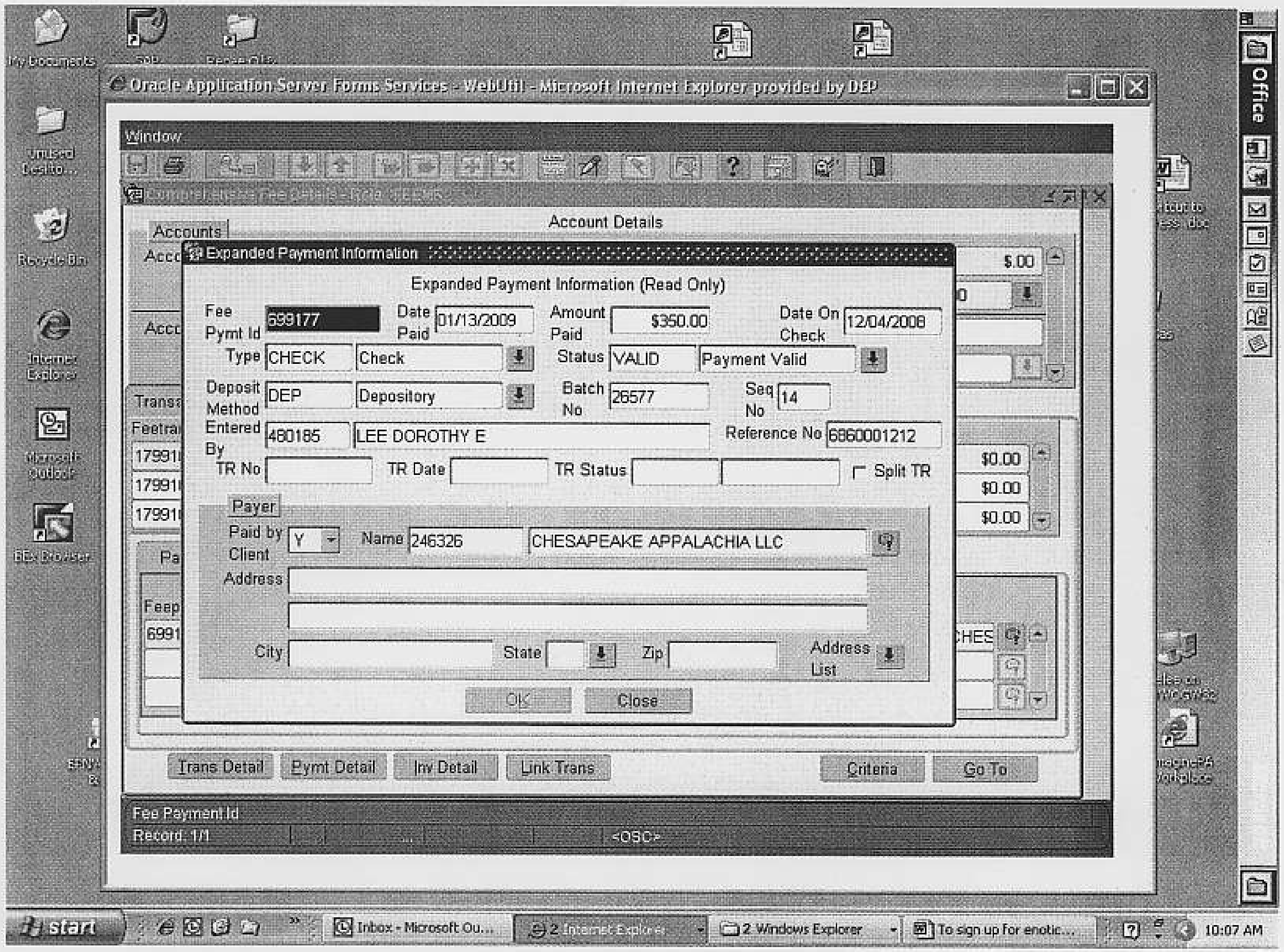
Transactions | Invoices

Feetrans Id	Auth Id	PF/SF	Other Id	Reason	Status	Date Due	Amount Due	Rev Cd	Balance
1799102	760352	SF	127-:	SRCHG	VALID	01/20/2009	$50.00	0017	$0.00
1799101	760352	SF	127-:	PRMIT	VALID	01/20/2009	$100.00	0017	$0.00
1799103	760352	SF	127-:	SRCHG	VALID	01/20/2009	$200.00	0017	$0.00

Payments | Adjustments | Related Trans

Feepmt Id	Type	Amount Paid	Ref	Date Paid	Date on Check	Amt Applied	Paid by Client	Payer	
699177	CHECK	$350.00	686(	01/13/2009	12/04/2008	$50.00	Y	246326	CHES

Trans Detail | Pymt Detail | Inv Detail | Link Trans | Criteria | Go To



My Documents
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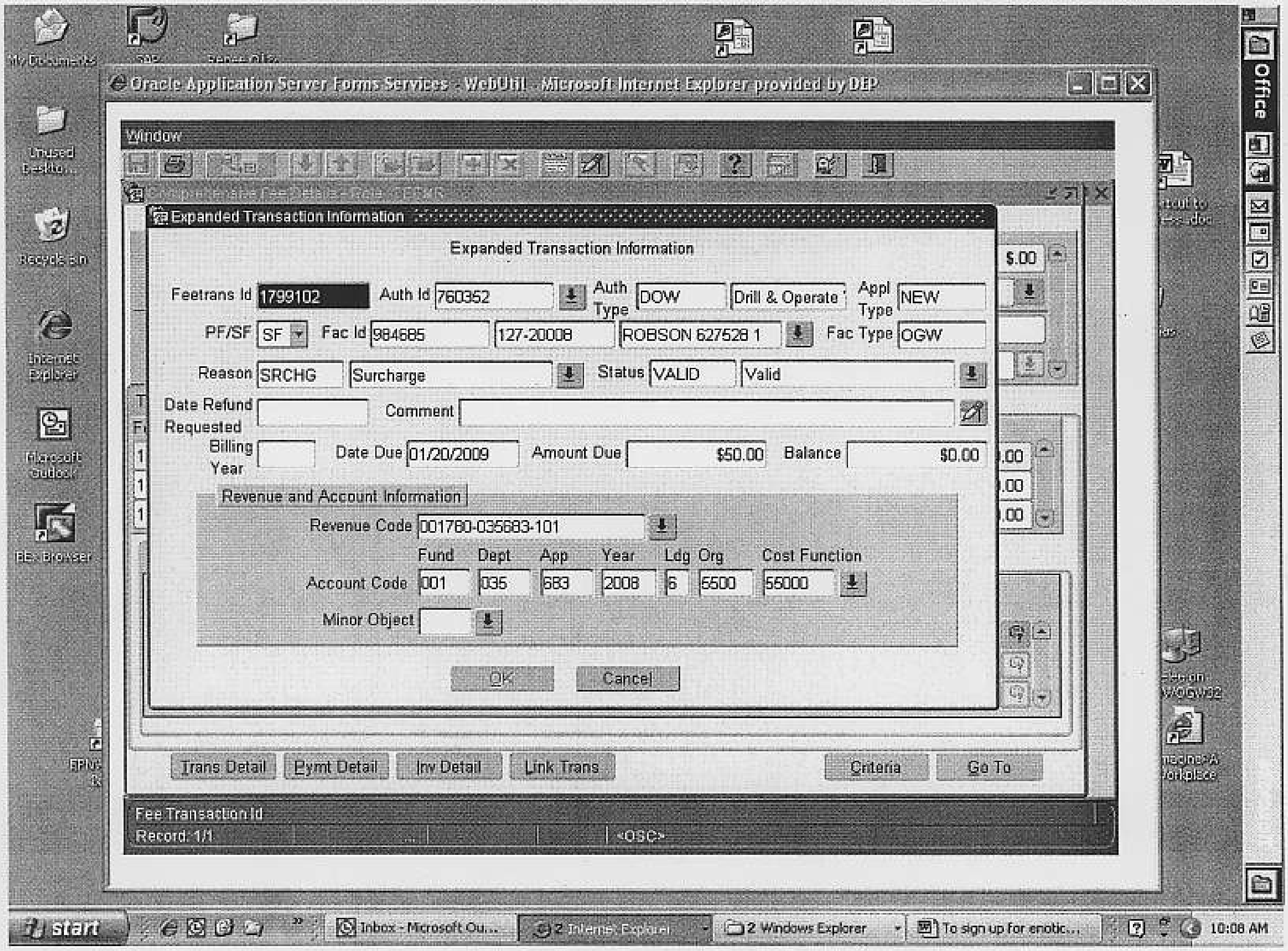
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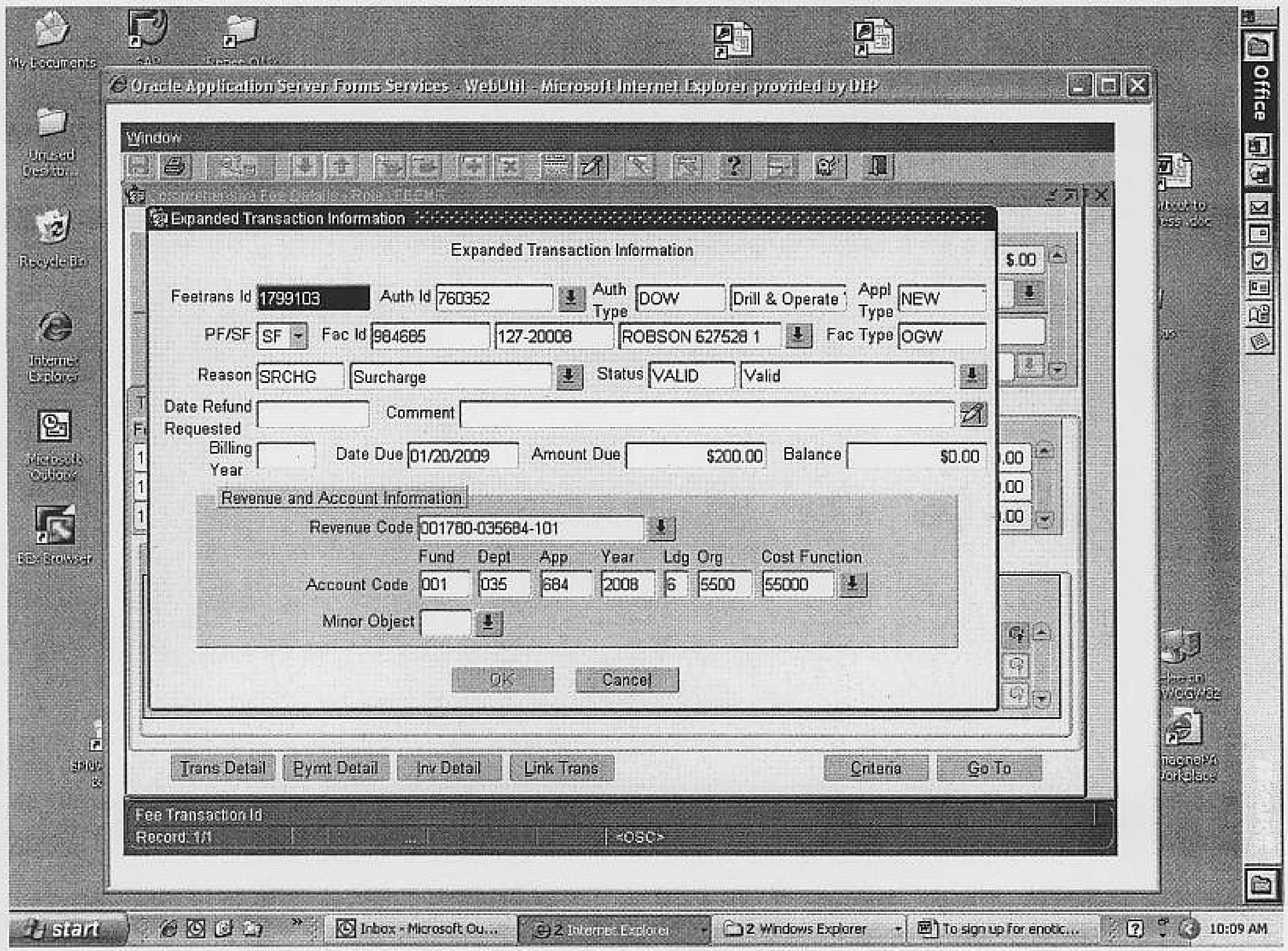

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Drill & Operate
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PF/SF SF
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127-20008
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Fund Dept App Year Ldg Org Cost Function
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COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL AND GAS MANAGEMENT PROGRAM

WELL PERMIT

DEP USE ONLY	
Permittee's eFACTS ID 277879	Auth ID 830993
Watershed Name Salt River Brook	Quality HQ

Permittee: NEWFIELD APPALACHIA PA LLC	OGO.#: OGO-67425	Permit Number: 37-127-20018-00	Date Issued: 05/25/2010
Address: 363 N SAM HOUSTON PKWY E		Farm Name & Well Number: DL TEEPLE 1 2H	Well Serial #
SUITE 2020		Municipality: Manchester	County: Wayne
HOUSTON, TX 77060-2424		7½ ' Quadrangle Name: Long Eddy	Map Section #: 5
Phone: (281) 674-2501	Project #	Latitude: 41-49-23.1900	Longitude: -75-11-39.3900
Surf Elev at Site: 1438 feet	Anticipated Total Depth: 8140 feet / Well Type: GS	Offset distances referenced to NE corner of map section. South 3725 feet West 7525 feet	

This permit covering the well operator and well location shown above is evidence of permission granted to conduct activities in accordance with the Oil and Gas Act and the Oil and Gas Conservation Law, if the well is subject to that act and any rules and regulations promulgated thereunder, subject to the conditions contained herein and in accordance with the application submitted for this permit. This permit does not convey any property rights.

This permit and the permittee's authority to conduct the activities authorized by this permit are conditioned upon operator's compliance with applicable law and regulations.

Notification must be given to the district oil and gas inspector, the surface landowner and political subdivision of the date well drilling will begin at least 24 hours prior to commencement of drilling activities.

The permittee hereby authorizes and consents to allow, without delay, employees or agents of the Department to have access to and to inspect all areas upon presentation of appropriate credentials, without advance notice or a search warrant. This includes any property, facility, operation or activity governed by the Oil and Gas Act, the Oil and Gas Conservation Law, the Coal and Gas Resource Coordination Act and other statutes applicable to oil and gas activities administered by the Department. The authorization and consent shall include consent to the Department to collect samples of wastewaters or gases, to take photographs, to perform measurements, surveys, and other tests, to inspect any monitoring equipment, to inspect the methods of operation and disposal, and to inspect and copy documents required by the Department to be maintained. The authorization and consent includes consent to the Department to examine books, papers, and records pertinent to any matter under investigation pursuant to the Oil and Gas Act or pertinent to a determination of whether the operator is in compliance with the above referenced statutes. This condition in no way limits any other powers granted to the Department under the Oil and Gas Act and other statutes, rules and regulations applicable to these activities as administered by the Department.

This permit does not relieve the operator from the obligation to comply with the Clean Streams Law and all statutes, rules and regulations administered by the Department.

Special Permit Conditions:

The permittee shall not withdraw or use water from water sources within the Commonwealth of Pennsylvania, for well fracing activities, unless the permittee does so in accordance with a Water Management Plan approved by the Department.

Permittee shall obtain a permit or Environmental Assessment approval from the Department prior to the construction of any dam, reservoir, water obstruction, and/or encroachment for which a permit or Environmental Assessment approval is required by 25 Pa. Code Chapter 105. Any dam embankment including centralized dam embankments utilized to impound freshwater or frac water associated with well fracing not requiring a permit pursuant to 25 Pa. Code Chapter 105 will be constructed in accordance with requirements of 25 Pa. Code §§ 78.56-78.63 and Department guidelines 5500-PM-OG0085 entitled, Design, construction and maintenance standards for dam embankments associated with impoundments for oil and gas wells.

Prior to fracturing the well, as part of its Preparedness, Prevention and Contingency Plan the permittee shall implement a Control and Disposal Plan for the control and disposal of fluids and residual wastes in accordance with 25 Pa. Code § 78.55. The Control and Disposal Plan shall identify the control and disposal methods and practices utilized to prevent pollutants from directly or indirectly reaching waters of the Commonwealth during the impoundment, production, processing and transportation of pollutants, including identification of the permitted processing or disposal facilities where residual wastes will be processed or disposed, in accordance with 25 Pa. Code §§ 78.55 and 91.34.

Prior to transport of the residual wastewater off site, chemical analysis and characterization of the waste shall be conducted and provided to the processing or disposal facility intended for acceptance of the waste in accordance with 25 Pa. Code § 287.54.

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The operator shall run a complete angular deviation survey of the intentionally deviated well. The deviation survey is to be obtained by a responsible well surveying company and shall be filed with the Department within thirty (30) days after well drilling together with other regularly required reports.

This permit expires **05/25/2011** unless drilling is commenced on or before that date and prosecuted with due diligence.

S. Craig Lobins

Regional Oil and Gas Program Manager

Stephen Watson	**2 Public Square**	**570-826-2320**
Oil & Gas Inspector	**Wilkes-Barre, PA 18711-0790**	**Telephone**

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pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL & GAS MANAGEMENT PROGRAM

ESM10-127-0001

DEP USE ONLY	
AUTH #	NC
Check # 1067827	Amount $ 3650.00

1067826 $500.00

PERMIT APPLICATION FOR DRILLING OR ALTERING A WELL

DEP USE ONLY

Notes	OGO #	Objection Date - Do not issue before:	Well Permit # 127-20018 NC
M	OGO # 67425	4/26/10	Special Cond. A B C D E F
	Bond # 12382	Date Approved: 5/21/10	Watershed Name: SALT RIVER BROOK
	C: 4/13/10 G: 4/26/10		Designation: HQ EV
	INV: 5-24-10		

Please read instructions before you begin filling in this form.

Applicant (Operator) Name	DEP Client ID#	Phone	FAX	Check if new address. ☐
Newfield Appalachia PA LLC	277879	281-674-2501	281-674-2902	
Mailing Address (Street or PO Box): 363 N. Sam Houston Pkwy E. Suite 2020	City: Houston	State: TX	Zip +4: 77060-2424	Country (if not USA)

(Well) Farm Name	Well #	Serial #
D.L. Teeple	1-2H	
County: WAYNE	Municipality: MANCHESTER	Project # (from DEP)

If you are applying for a permit to redrill, drill deeper, or alter a well that was previously permitted or registered, ***or for a well site that was previously permitted but not drilled,*** check this box ☐ and enter the permit or registration number here:

If applying for a permit to rework an existing well not registered or permitted, check this box ☐ and **enter date drilled**, if known:____________ (see instructions)

PNDI Attached: ☒ Any "hit" must include accepted mitigation plan from applicable agency.

PERMIT TYPE
Check applicable.
Application is to:
- ☒ Drill a new well
- ☐ Deepen a well
- ☐ Redrill a well
- ☐ Alter a well
- ☒ E&S Control Module
- ☐ Other (specify)

TYPE OF WELL
Check one.
- ☒ Gas
- ☐ Oil
- ☐ Comb. (gas & oil)
- ☐ Injection, recovery
- ☐ Injection, disposal
- ☐ Coalbed Methane
- ☐ Gas Storage
- ☐ Other (specify)

APPLICATION FEE
Check applicable.
- ☒ Marcellus Well: Non-Vertical
- ☐ Marcellus Well: Vertical
- ☐ Non-Marcellus Well: Non-Vertical
- ☐ Non-Marcellus Well: Vertical
- ☐ $200 (Home Use Well)
- ☒ $500 E&S Fee
- ☐ $ 0 (Rehab orphan)
- ☐ Vertical: Length _____ ft.
- ☒ Marcellus: Length 13,548.8 ft.
- ☐ Non-Vertical: Length _____ ft.

Total Application Fee $ 4,150

COORDINATION WITH REGULATIONS AND OTHER PERMITS	Yes	No
1. Will the well be subject to the **Oil and Gas Conservation Law**? If "No," go to 2).	☐	☒
a. If "Yes" to #1, is the well at least 330 feet from outside lease or unit boundary?	☐	☐
b. Does the location fall within an area covered by a spacing order?	☐	☐
2. Will the well penetrate a **workable coal seam**? If "No," include justification and supporting documentation.	☐	☒
3. If the well will penetrate a **workable coal seam**, and the well is a "non-conservation" gas well, does the location comply with the distance requirements of Section 7 of the Coal and Gas Resource Coordination Act? (At least 1,000 feet from all existing wells).	☐	☐
a. If "No," is the required exception request attached? (Check here if re-working an existing well: ☐ N/A)	☐	☐
4. Will the well be drilled at a location where the **coal** has been removed?	☐	☒
5. Will the well be drilled through an **active (operating or projected) coalmine**, or within 1,000 feet of the boundary?	☐	☒
a. If "Yes," print the names of: Mine: Operator:		
6. Will the well penetrate or be within 2,000 feet of an active **gas storage reservoir** boundary?	☐	☒
a. If Yes, print the names of: Storage Field: Operator:		
7. Is the proposed well location within the permitted area of a **landfill**?	☐	☒
8. Will the well site be within 100 feet (measured horizontally) of a **stream, spring or body of water** identified on the most current 7½' topographic map?	☐	☒
a. If "Yes," is a request for a waiver (form 5500-FM-OG0057), and E&S control plan attached?	☐	☐
9. Will the well site be within 100 feet of a **wetland** or in a **wetland**?	☐	☒
a. Is the well site within 100 feet of a wetland greater than one acre in size?	☐	☐
If yes, is a waiver request (form 5500-FM-OG0057) and E&S control plan attached?	☐	☐
10. Will the well be drilled within 200 feet (horizontally) from any existing **building** or an existing **water supply**?	☐	☒
a. If "Yes," is written consent from the owner attached?	☐	☐
b. If written consent is not attached, is a variance request (form 5500-FM-OG0058) attached?	☐	☐

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NORTHWEST REGIONAL OFFICE

DEP USE ONLY
Date Stamps/Notes
Auth 830993
Site 733332
Clnt 277879
APS 717984
Acct 1070740
PF 729789
SF 1012170

	Yes	No
11. Will the well be located where it may impact a public resource as outlined in the "**Coordination of a Well Location with Public Resources**" form 5500-PM-OG0076? If yes, attach a competed copy of the form.	☐	☒
12. Is the well site in a **Special Protection** High Quality (HQ) or Exceptional Value (EV) watershed?	☒	☐
13. Is this well part of a development where you need an **Earth Disturbance Permit** for Oil and Gas Activities disturbing more than 5 acres? If yes, attach a completed Erosion Sediment and Stormwater Control Module or list the number and date of the ESCGP-1 Approval. See Attached Module	☒	☐

Signature of Applicant — The person signing this form attests that they have the authority to submit this application on behalf of the applicant, and that the information, including all related submissions, is true and accurate to the best of their knowledge.

Signature of Person Authorized to Submit Application	(Print or Type)	Name of Signer: DONALD F. SLEETH Title: Drilling Manager	Date 4-12-10
Donald F. Sleeth			

Application Preparer/Contact: ANDREW STRASSNER Phone: 412-862-7963

127-20018

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DEPARTMENT OF ENVIRONMENTAL PROTECTION

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL & GAS MANAGEMENT PROGRAM

Farm Name - Well #	
D.L. Teeple 1-2H	
Applicant Name: Newfield Appalachia PA LLC	DEP ID#: 277879
DEP USE ONLY	APS #

PERMIT APPLICATION FOR DRILLING OR ALTERING A WELL

Page 2 --- Record of Notification / Written Consent

List the following: surface landowner; all landowners or water purveyors whose water supplies are within 1,000 feet of this proposed well location; gas storage operator if within 2000 feet; all coal owners and lessees of all underlying workable coal seams; operators of underground coal mines at the proposed location; and coal operators with a deep mine within 1,000 feet. Mark the boxes, "X," which show the parties' interests. Use additional forms if you need more space. You are required to notify each of these parties.

Name	Address	Surface Landowner	Coal Owner	Coal Lessee	Coal Mine Operator	Gas Storage Operator	Within 1,000 feet: Surf Owner with Water	Within 1,000 feet: Water Purveyor	Within 1,000 feet: Coal Mine Operator	Notification (Note the means and attach proof.) Certified Mail Dates: Sent	Certified Mail Dates: Return Receipt	Address Affidavit	Written Consent
Dale L & Ella E Teeple	13 Teeple Road Equinunk, Pa 18417-3514	X					X						X
Roger D & Patricia A Hazen	3697 Hancock Hwy Equinunk , Pa 18417-3164						X						X
Granville W & Charlene Teeple	24 Sault River Road Equinunk, Pa 18417-3501						X			3-25-10	3-29-10		
Cynthia F Rowe	3743 Hancock Hwy Equinunk, Pa 18417-3166						X			3-25-10	3-27-10		

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NORTHWEST REGIONAL OFFICE

Optional: Signature below indicates the party's approval of the well location, and waives the 15-day objection period. Check applicable box.

☐ Water Purveyor or ☑ Landowner with water supply within 1,000 ft. Dale L Teeple Ella E. Teeple	Date 3-31-10	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
☐ Water Purveyor or ☐ Landowner with water supply within 1,000 ft.	Date	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
☐ Water Purveyor or ☐ Landowner with water supply within 1,000 ft.	Date	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
☐ Water Purveyor or ☐ Landowner with water supply within 1,000 ft.	Date	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
Surface Landowner at proposed location Dale L Teeple	Date 3-31-10	Coal Operator within 1,000 feet of proposed location	Date
Surface Landowner at proposed location Ella E. Teeple	Date 3-31-10	Gas Storage Operator within 2,000 feet	Date

Signature below indicates written consent. Check applicable box.

Owner of: ☐ water supply, or ☐ building within 200 feet	Date
Address (of above)	
Owner of: ☐ water supply, or ☐ building within 200 feet	Date
Address (of above)	

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COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL & GAS MANAGEMENT PROGRAM

Farm Name - Well #	
D.L. Teeple 1-2H	
Applicant Name	DEP ID#
Newfield Appalachia PA LLC	277879
DEP USE ONLY	APS #

127-20018

PERMIT APPLICATION FOR DRILLING OR ALTERING A WELL

Page 2 — Record of Notification / Written Consent

List the following: surface landowner; all landowners or water purveyors whose water supplies are within 1,000 feet of this proposed well location; gas storage operator if within 2000 feet; all coal owners and lessees of all underlying workable coal seams; operators of underground coal mines at the proposed location; and coal operators with a deep mine within 1,000 feet. Mark the boxes, "X," which show the parties' interests. Use additional forms if you need more space. You are required to notify each of these parties.

Name	Address	Surface Landowner	Coal Owner	Coal Lessee	Coal Mine Operator	Gas Storage Operator	Within 1,000 feet: Surf Owner with Water	Within 1,000 feet: Water Purveyor	Within 1,000 feet: Coal Mine Operator	Notification (Note the means and attach proof.) Certified Mail Dates: Sent	Certified Mail Dates: Return Receipt	Address Affidavit	Written Consent
Dale L & Ella E Teeple	13 Teeple Road Equinunk, Pa 18417-3514	X					X						X
Roger D & Patricia A Hazen	3697 Hancock Hwy Equinunk , Pa 18417-3164						X						X
Granville W & Charlene Teeple	24 Sault River Road Equinunk, Pa 18417-3501						X			3-25-10	3-29-10		
Cynthia F Rowe	3743 Hancock Hwy Equinunk, Pa 18417-3166						X			3-25-10	3-27-10		

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APR 13 2010
ENVIRONMENTAL PROTECTION
NORTHWEST REGIONAL OFFICE

Optional: Signature below indicates the party's approval of the well location, and waives the 15-day objection period. Check applicable box.

- ☐ Water Purveyor or ☒ Landowner with water supply within 1,000 ft. Roger D. Hazen — Date 03/30/2010
- ☐ Water Purveyor or ☒ Landowner with water supply within 1,000 ft. Patricia A. Hazen — Date 3/30/2010
- ☐ Water Purveyor or ☐ Landowner with water supply within 1,000 ft. — Date
- ☐ Water Purveyor or ☐ Landowner with water supply within 1,000 ft. — Date
- Surface Landowner at proposed location — Date
- Surface Landowner at proposed location — Date

- Coal ☐ Operator, ☐ Owner, or ☐ Lessee — Date
- Coal ☐ Operator, ☐ Owner, or ☐ Lessee — Date
- Coal ☐ Operator, ☐ Owner, or ☐ Lessee — Date
- Coal ☐ Operator, ☐ Owner, or ☐ Lessee — Date
- Coal Operator within 1,000 feet of proposed location — Date
- Gas Storage Operator within 2,000 feet — Date

Signature below indicates written consent. Check applicable box.

- Owner of: ☐ water supply, or ☐ building within 200 feet — Date
  Address (of above)
- Owner of: ☐ water supply, or ☐ building within 200 feet — Date
  Address (of above)

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DEPARTMENT OF ENVIRONMENTAL PROTECTION

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL & GAS MANAGEMENT PROGRAM

Farm Name - Well #	
D.L. Teeple 1-2H	
Applicant Name: Newfield Appalachia PA LLC	DEP ID#: 277879
DEP USE ONLY	APS #

127-20018

PERMIT APPLICATION FOR DRILLING OR ALTERING A WELL
Page 2 --- Record of Notification / Written Consent

List the following: surface landowner; all landowners or water purveyors whose water supplies are within 1,000 feet of this proposed well location; gas storage operator if within 2000 feet; all coal owners and lessees of all underlying workable coal seams; operators of underground coal mines at the proposed location; and coal operators with a deep mine within 1,000 feet. Mark the boxes, "X," which show the parties' interests. Use additional forms if you need more space. You are required to notify each of these parties.

Name	Address	Surface Landowner	Coal Owner	Coal Lessee	Coal Mine Operator	Gas Storage Operator	Within 1,000 feet: Surf Owner with Water	Within 1,000 feet: Water Purveyor	Within 1,000 feet: Coal Mine Operator	Notification (Note the means and attach proof.) Certified Mail Dates: Sent	Certified Mail Dates: Return Receipt	Address Affidavit	Written Consent
Dale L & Ella E Teeple	13 Teeple Road Equinunk, Pa 18417-3514	X					X						X
Roger D & Patricia A Hazen	3697 Hancock Hwy Equinunk , Pa 18417-3164						X						X
Granville W & Charlene Teeple	24 Sault River Road Equinunk, Pa 18417-3501						X			3-25-10	3-29-10		
Cynthia F Rowe	3743 Hancock Hwy Equinunk, Pa 18417-3166						X			3-25-10	3-27-10		

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Optional: Signature below indicates the party's approval of the well location, and waives the 15-day objection period. Check applicable box.

☐ Water Purveyor or ☐ Landowner with water supply within 1,000 ft.	Date	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
☐ Water Purveyor or ☐ Landowner with water supply within 1,000 ft.	Date	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
☐ Water Purveyor or ☐ Landowner with water supply within 1,000 ft.	Date	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
☐ Water Purveyor or ☐ Landowner with water supply within 1,000 ft.	Date	Coal ☐ Operator, ☐ Owner, or ☐ Lessee	Date
Surface Landowner at proposed location	Date	Coal Operator within 1,000 feet of proposed location	Date
Surface Landowner at proposed location	Date	Gas Storage Operator within 2,000 feet	Date

Signature below indicates written consent. Check applicable box.

Owner of: ☐ water supply, or ☐ building within 200 feet	Date
Address (of above)	
Owner of: ☐ water supply, or ☐ building within 200 feet	Date
Address (of above)	

Acct-676742

5500-PM-OG0001a 3/2009
Application

pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
BUREAU OF OIL AND GAS MANAGEMENT

DEP USE ONLY	
APS # 717984	Site # 733332
Permit # 127-20018	Auth ID # 830995

Erosion, Sediment and Stormwater Control MODULE

ESM10-127-0001

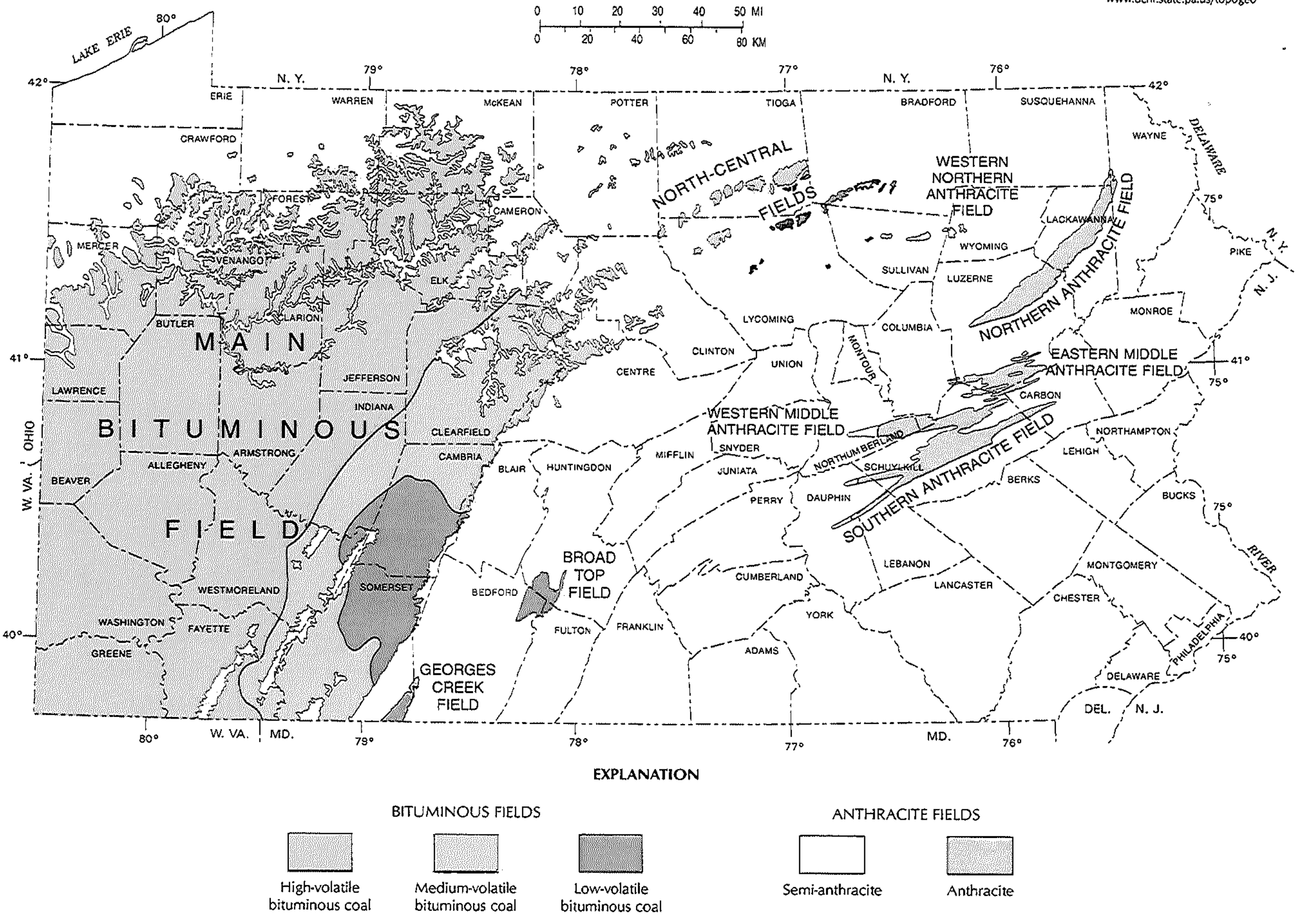
	Please complete this section if your earth disturbance activities will disturb 5 acres or greater.
1.	Project Site Information.
	a. Attach topographic map of proposed location.
	b. Location of surface waters which may receive runoff and the waters classification, pursuant to Chapter 93 and the "statewide existing use listing": Receiving Waters/Watershed Name Salt River Brook / Little Equinunk Creek Chapter 93 Designated Use or Existing Use Stream Classification High Quality Exceptional Value Other ________ RECEIVED APR 13 2010 ENVIRONMENTAL PROTECTION NORTHWEST REGIONAL OFFICE
2.	Erosion and Sediment Control authorization for Earth Disturbance Associated with Oil and Gas Activities filing fee of $500 payable to: Commonwealth of Pennsylvania, Clean Water Fund.
3.	**Compliance History** Is the applicant in violation of any existing permit, regulation, order or schedule of compliance issued by the Department? If yes, provide the permit number or facility name, a brief description of the violation, the compliance schedule (including dates and steps to achieve compliance) and the current compliance status. Yes No (Attach on a separate sheet, if needed)
4.	**Erosion & Sediment Control and Site Restoration Plan** At least fourteen days before the commencement of earth disturbance activities, or earlier in accordance with applicable Chapter 105 permitting requirements, the applicant shall provide the appropriate DEP Regional Oil and Gas Program Office with the following: A. An Erosion and Sediment Control and Site Restoration Plan that meets the requirements of 25 Pa. Code Chapters 78 and102, and in the Department's *Erosion and Sediment Pollution Control Manual*, No. 363-2134-008, as amended and updated and the Department's *Oil and Gas Operator's Manual*, No. 550-0300-001. B. The Site Restoration Plan shall include PCSM BMPs designed and implemented to meet the requirements of 25 Pa. Code Chapter 93, and consistent with the *Pennsylvania Stormwater Best Management Practices Manual*, No. 363-0300-002, as amended and updated. Both the E&S and Site Restoration Plan shall minimize the accelerated erosion and sedimentation and shall eliminate the net change in post construction stormwater runoff as compared to the amount of preconstruction stormwater runoff. This shall be accomplished first through the use of site design and nonstructural BMP approaches, and if necessary structural filtration, infiltration, and runoff control BMPs in accordance with *Erosion and Sediment Pollution Control Manual*, No. 363-2134-008, *Oil and Gas Operator's Manual*, No. 550-0300-001and *Stormwater Best Management Practices Manual*, No. 363-0300-002, as amended and updated. Supporting calculations and measurements for PCSM BMPs are not required unless there will be permanent impervious paved surfaces or above-ground structures or facilities (excluding well-heads and brine storage tanks and other such ancillary equipment. See model plan for further guidance). Crushed rock or gravel roads are not considered impervious. Both the E&S and Site Restoration Plan shall be developed and sealed by a licensed professional engineer, surveyor or professional geologist, and shall contain the following certification: *I do hereby certify to the best of my knowledge, information and belief, that the Erosion and Sediment Control and Site Restoration Plan are true and correct, represent actual field conditions and are in accordance with the 25 Pa. Code Chapters 78 and 102 of the Department's rules and regulations. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.* Print Name: ________ Signature: ________ Company: ________ Address: ________ Phone: ________
5.	**Area Wide or Phased E&S and Stormwater Management** List the well permit numbers for any other well permit that is or will be included in the E&S and/or Site Reclamation Plan for this project: ________

MAP 11

DCNR

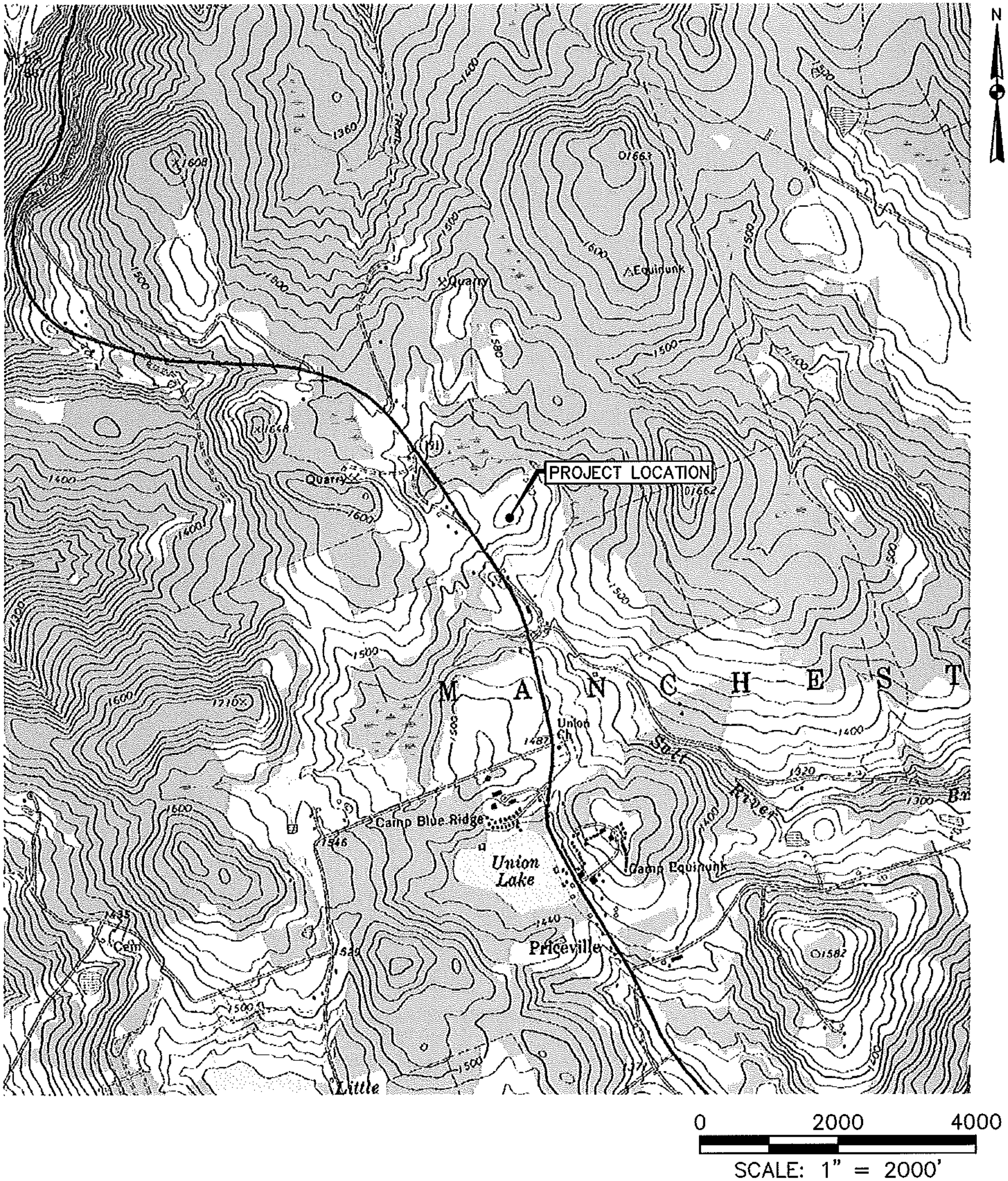
DISTRIBUTION OF PENNSYLVANIA COALS

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF
CONSERVATION AND NATURAL RESOURCES
BUREAU OF TOPOGRAPHIC AND GEOLOGIC SURVEY
www.dcnr.state.pa.us/topogeo



Prepared by Bureau of Topographic and Geologic Survey.
Third Edition, Revised, 2000; Third Printing, 2008.

2200-MP-DCNR0855
Printed on Recycled Paper



R:_Marcellus Shale Projects\Newfield\2679 – Newfield Wells\Teeple 1-1\Figures\2568FG001.dwg PIT BEN.HOPPE 3/4/2010 8:49:25 AM

TETRA TECH

WWW.TETRATECH.COM

661 ANDERSEN DRIVE – FOSTER PLAZA 7
PITTSBURGH, PA 15220
T: (412) 921-7090 | F: (412) 921-4040

NEWFIELD APPALACHIA PA LLC
WAYNE COUNTY, PENNSYLVANIA

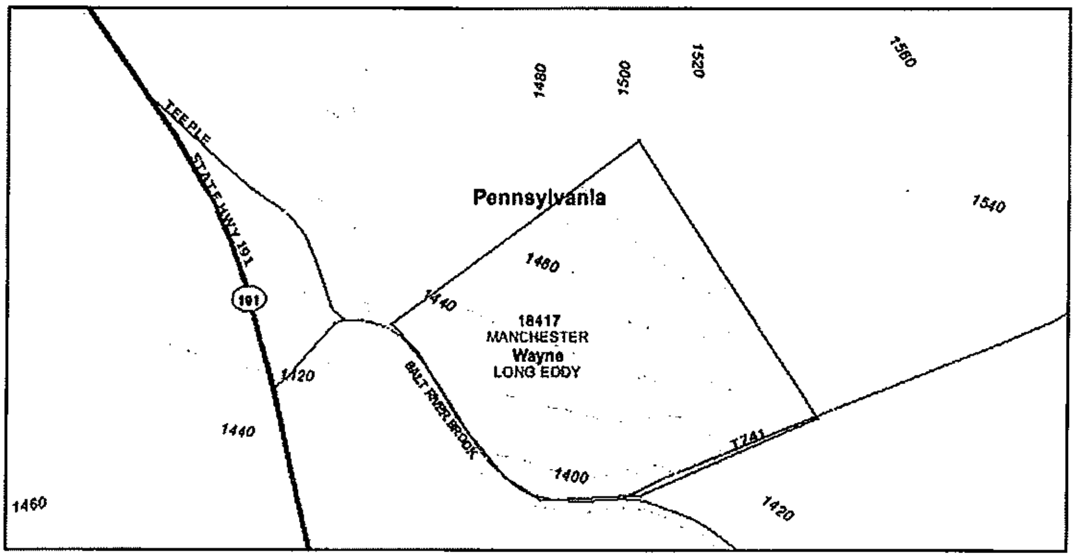
TEEPLE WELL PAD
LOCATION MAP
SCALE: 1" = 2000'

DATE:	3/4/10
PROJECT NO.:	112C02568
DESIGNED BY:	RAL
DRAWN BY:	BH
CHECKED BY:	RAL
SHEET: 1 OF 2	

ATTACHMENT 1

1. PROJECT INFORMATION

Project Name: **D.L. Teeple Well**
Date of review: **3/3/2010 8:00:27 AM**
Project Category: **Energy Storage, Production, and Transfer,Energy Production (generation),Oil or Gas - new wells, expansion of well field**
Project Area: **20.3** acres
County: **Wayne** Township/Municipality: **Manchester**
Quadrangle Name: **LONG EDDY**
ZIP Code: **18417**
Decimal Degrees: **41.82487 N, --75.19285 W**
Degrees Minutes Seconds: **41° 49' 29.5" N, -75° 11' 34.3" W**



2. SEARCH RESULTS

Agency	Results	Response
PA Game Commission	No Known Impact	No Further Review Required
PA Department of Conservation and Natural Resources	No Known Impact	No Further Review Required
PA Fish and Boat Commission	No Known Impact	No Further Review Required
U.S. Fish and Wildlife Service	No Known Impact	No Further Review Required

As summarized above, Pennsylvania Natural Diversity Inventory (PNDI) records indicate no known impacts to threatened and endangered species and/or special concern species and resources within the project area. Therefore, based on the information you provided, no further coordination is required with the jurisdictional agencies. This response does not reflect potential agency concerns regarding impacts to other ecological resources, such as wetlands.

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3. AGENCY COMMENTS

Regardless of whether a DEP permit is necessary for this proposed project, any potential impacts to threatened and endangered species and/or special concern species and resources must be resolved with the appropriate jurisdictional agency. In some cases, a permit or authorization from the jurisdictional agency may be needed if adverse impacts to these species and habitats cannot be avoided.

These agency determinations and responses are **valid for one year** (from the date of the review), and are based on the project information that was provided, including the exact project location; the project type, description, and features; and any responses to questions that were generated during this search. If any of the following change: 1) project location, 2) project size or configuration, 3) project type, or 4) responses to the questions that were asked during the online review, the results of this review are not valid, and the review must be searched again via the PNDI Environmental Review Tool and resubmitted to the jurisdictional agencies. The PNDI tool is a primary screening tool, and a desktop review may reveal more or fewer impacts than what is listed on this PNDI receipt. The PNDI tool is a primary screening tool, and a desktop review may reveal more or fewer impacts than what is listed on this PNDI receipt.

PA Game Commission

RESPONSE: No Impact is anticipated to threatened and endangered species and/or special concern species and resources.

PA Department of Conservation and Natural Resources

RESPONSE: No Impact is anticipated to threatened and endangered species and/or special concern species and resources.

PA Fish and Boat Commission

RESPONSE: No Impact is anticipated to threatened and endangered species and/or special concern species and resources.

U.S. Fish and Wildlife Service

RESPONSE: No impacts to **federally** listed or proposed species are anticipated. Therefore, no further consultation/coordination under the Endangered Species Act (87 Stat. 884, as amended; 16 U.S.C. 1531 *et seq.* is required. Because no take of federally listed species is anticipated, none is authorized. This response does not reflect potential Fish and Wildlife Service concerns under the Fish and Wildlife Coordination Act or other authorities.

4. DEP INFORMATION

The Pa Department of Environmental Protection (DEP) requires that a signed copy of this receipt, along with any required documentation from jurisdictional agencies concerning resolution of potential impacts, be submitted with applications for permits requiring PNDI review. For cases where a "Potential Impact" to threatened and endangered species has been identified before the application has been submitted to DEP, the application should not be submitted until the impact has been resolved. For cases where "Potential Impact" to special concern species and resources has been identified before the application has been submitted, the application should be submitted to DEP along with the PNDI receipt, a completed PNDI form and a USGS 7.5 minute quadrangle map with the project boundaries delineated on the map. The PNDI Receipt should also be submitted to the appropriate agency according to directions on the PNDI Receipt. DEP and the jurisdictional agency will work together to resolve the potential impact(s). See the DEP PNDI policy at http://www.naturalheritage.state.pa.us.

5. ADDITIONAL INFORMATION

The PNDI environmental review website is a **preliminary** screening tool. There are often delays in updating species status classifications. Because the proposed status represents the best available information regarding the conservation status of the species, state jurisdictional agency staff give the proposed statuses at least the same consideration as the current legal status. If surveys or further information reveal that a threatened and endangered and/or special concern species and resources exist in your project area, contact the appropriate jurisdictional agency/agencies immediately to identify and resolve any impacts.

For a list of species known to occur in the county where your project is located, please see the species lists by county found on the PA Natural Heritage Program (PNHP) home page (www.naturalheritage.state.pa.us). Also note that the PNDI Environmental Review Tool only contains information about species occurrences that have actually been reported to the PNHP.

6. AGENCY CONTACT INFORMATION

PA Department of Conservation and Natural Resources
Bureau of Forestry, Ecological Services Section
400 Market Street, PO Box 8552, Harrisburg, PA. 17105-8552
Fax:(717) 772-0271

U.S. Fish and Wildlife Service
Endangered Species Section
315 South Allen Street, Suite 322, State College, PA. 16801-4851
NO Faxes Please.

PA Fish and Boat Commission
Division of Environmental Services
450 Robinson Lane, Bellefonte, PA. 16823-7437
NO Faxes Please

PA Game Commission
Bureau of Wildlife Habitat Management
Division of Environmental Planning and Habitat Protection
2001 Elmerton Avenue, Harrisburg, PA. 17110-9797
Fax:(717) 787-6957

7. PROJECT CONTACT INFORMATION

Name: Rick Lowry
Company/Business Name: Tetra Tech NUS, Inc
Address: 661 Andersen Drive
City, State, Zip: Pittsburgh, PA 15220
Phone:(412) 921-8375 Fax:(412) 921-4040
Email: Rick.Lowry@TetraTech.com

8. CERTIFICATION

I certify that ALL of the project information contained in this receipt (including project location, project size/configuration, project type, answers to questions) is true, accurate and complete. In addition, if the project type, location, size or configuration changes, or if the answers to any questions that were asked during this online review change, I agree to re-do the online environmental review.

(Agent) 03/16/10

applicant/project proponent signature date

Confirmation Services

Package ID: 9171082133393775234354 E-CERTIFIED
Destination ZIP Code: 78840 1STCL REGULAR LETTER
Customer Reference:
Recipient: TCLA and F.H Whitehead PBP Account #: 13945647
Address: 11 Meadow Ln Serial #: 4253999
Del Rio Texas 78840 MAR 24 2010 4:58P

Confirmation Services

Package ID: 9171082133393775234361 E-CERTIFIED
Destination ZIP Code: 76950 1STCL REGULAR LETTER
Customer Reference:
Recipient: W.L Whitehead PBP Account #: 13945647
Address: P.O Box 1508 Serial #: 4253999
Sonora, Tx 76950 MAR 24 2010 4:58P

Confirmation Services

Package ID: 9171082133393775234385 E-CERTIFIED
Des 1STCL REGULAR FLAT
Cus
Rec Cynthia F. Rowe PBP Account #: 13945647
Add 3743 Hancock Hwy. Serial #: 4253999
Equinunk, PA 18417 MAR 25 2010 2:37P

Confirmation Services

Package ID: 9171082133393775234408 E-CERTIFIED
Desti 1STCL REGULAR FLAT
Custo
Recip Granville W. & Charlene Teeple PBP Account #: 13945647
Addr 24 Sault River Rd. Serial #: 4253999
Equinunk, PA 18471 MAR 25 2010 2:37P

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Confirmation Services

Package ID
Desl
Cus
Recl
Add

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Granville W. & Charlene Teeple
24 Sault River Rd.
Equinunk, PA 18471

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X G.C Teeple ☐ Agent ☐ Addressee

B. Received by (Printed Name) G C Teeple C. Date of Delivery 3-29-10

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☐ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 91 7108 2133 3937 7523 4408

PS Form 3811, February 2004 Domestic Return Receipt 102595-02-M-154

Confirmation Services

Package ID: 9171082133393775234354 E-CERTIFIED
Destination ZIP Code: 78840 1STCL REGULAR LETTER
Customer Reference:
Recipient: TCLA and F.H Whitehead PBP Account #: 13945647
Address: 11 Meadow Ln Serial #: 4253999
Del Rio Texas 78840 MAR 24 2010 4:58P

Confirmation Services

Package ID: 9171082133393775234361 E-CERTIFIED
Destination ZIP Code: 76950 1STCL REGULAR LETTER
Customer Reference:
Recipient: W.L Whitehead PBP Account #: 13945647
Address: P.O Box 1508 Serial #: 4253999
Sonora, Tx 76950 MAR 24 2010 4:58P

Confirmation Services

Package ID: 9171082133393775234385 E-CERTIFIED
Des 1STCL REGULAR FLAT
Cus
Rec Cynthia F. Rowe PBP Account #: 13945647
Add 3743 Hancock Hwy. Serial #: 4253999
Equinunk, PA 18417 MAR 25 2010 2:37P

Confirmation Services

Package ID: 9171082133393775234408 E-CERTIFIED
Desti 1STCL REGULAR FLAT
Cust
Recip Granville W. & Charlene Teeple PBP Account #: 13945647
Addr 24 Sault River Rd. Serial #: 4253999
Equinunk, PA 18471 MAR 25 2010 2:37P

RECEIVED
APR 13 2010
ENVIRONMENTAL PROTECTION
NORTHWEST REGIONAL OFFICE

Confirmation Services

Package ID: 9171082133393775234415
Desl
Cu
Re
Ad

SENDER: COMPLETE THIS SECTION

- Complete items 1, 2, and 3. Also complete item 4 if Restricted Delivery is desired.
- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

Cynthia F. Rowe
3743 Hancock Hwy.
Equinunk, PA 18417

COMPLETE THIS SECTION ON DELIVERY

A. Signature ☐ Agent ☐ Addressee
X Gustin Rowe

B. Received by (Printed Name) C. Date of Delivery 3/27/10

D. Is delivery address different from item 1? ☐ Yes
If YES, enter delivery address below: ☐ No

3. Service Type
☐ Certified Mail ☐ Express Mail
☐ Registered ☐ Return Receipt for Merchandise
☐ Insured Mail ☐ C.O.D.

4. Restricted Delivery? (Extra Fee) ☐ Yes

2. Article Number (Transfer from service label) 91 7108 2133 3937 7523 4392

...2004 Domestic Return Receipt 102595-02-M-1540

5500-PM-OG0002-DWG Rev. 09/2008

pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
Oil and Gas Management Program
WELL LOCATION PLAT

DEP USE ONLY	DEP Application Tracking #	G: JR 4/26/10
	Permit # 127-20018	C:
	Project #	

Denotes location of well on topo map.

Well is located on topo map 3,725 feet south of latitude 41 ° 50 ' 00 "

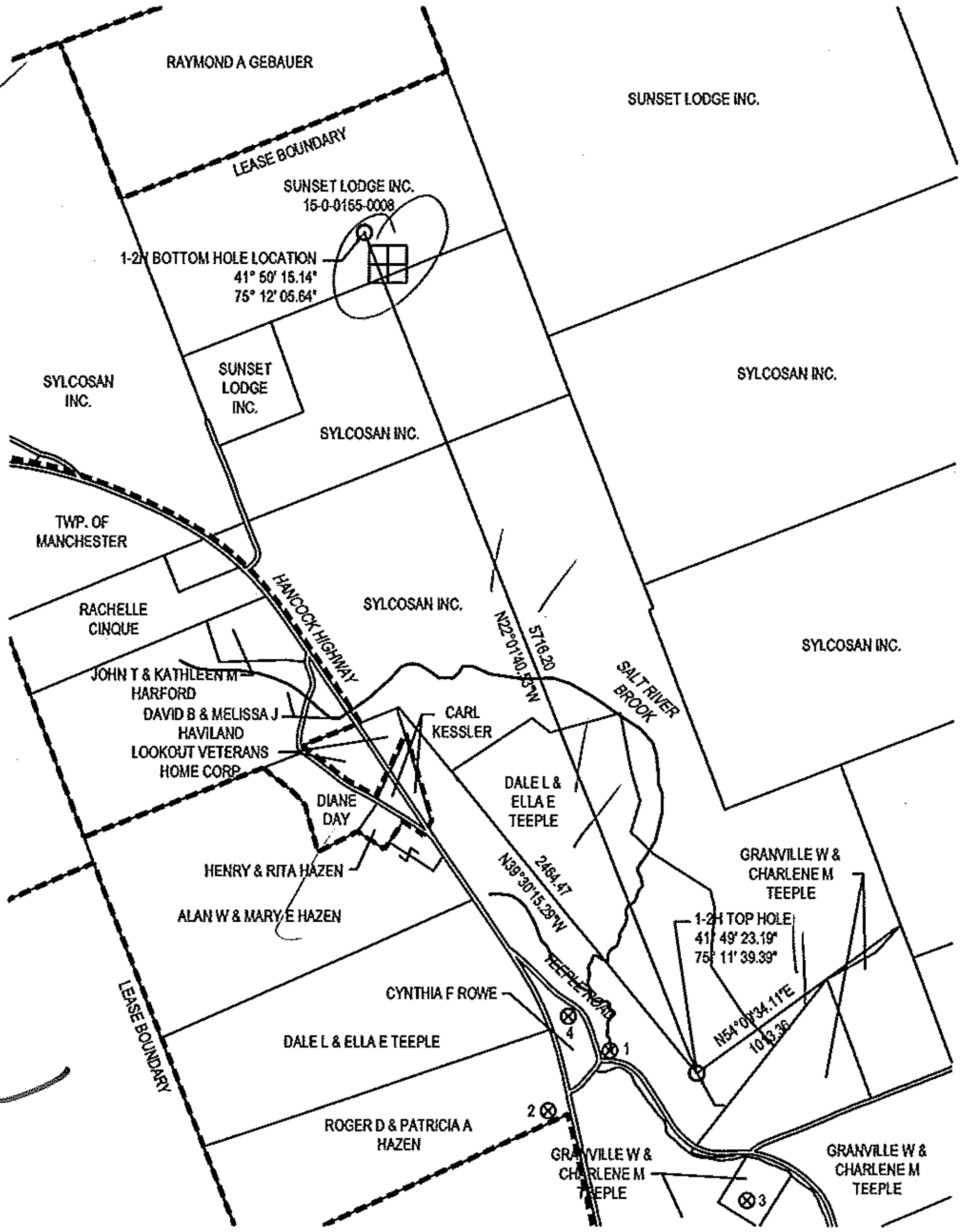
True Latitude: NORTH
41 ° 49 ' 23.19 "

True Longitude: WEST
75 ° 11 ' 39.39 "

WELL NORTHING - Y
613,811.1

WELL EASTING - X
2,665,002.7

Well is located on topo map 7,525 feet west of longitude 75 ° 10 ' 00 "



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COMMONWEALTH OF PENNSYLVANIA
REGISTERED PROFESSIONAL
ALLAN R BERENBROK
ENGINEER
037262-E

Surveyor or Engineer TETRA TECH   Phone # (412) 921-8873   Dwg. # 1-2H   Date 4/7/2010   Scale 1"= 1200'   Tract Acreage

Lat. & Long Metadata: Method GPS, Accuracy +/- 1 ft. Datum NAD83	Elevation Metadata: Method GPS, Accuracy +/- 1 ft. Datum NAD83; Survey Date Jan. 2010
Applicant / Well Operator Name: Newfield Appalachia PA LLC	Well(Farm) Name: D.L. Teeple; Well # 1-2H; Serial #
Address: 363 N. Sam Houston Parkway E., Suite 2020, Houston, TX 77060	County - Code: Wayne; Municipality: Manchester; Well Type: Gas
Surface Landowner / Lessor: Dale and Ella Teeple	USGS 71/2 Quadrangle Map Name: Long Eddy, NY; Map Section 5; Surface Elevation 1438 ft.
Target Formation(s): Marcellus Shale	Angle & Course of Deviation (Drilling): N22D 01' 40.53"W 5,716.20'; Anticipated Total Depth TVD 8,140 ft. TMD 13,548.80 ft.

Surface Owner or Water Purveyor with a Water Supply within 1,000 ft.	Approximate Course and Distance to Water Supply	Owner, Lessee, or Operator of Workable Coal Seam	Name of Coal Seam Owned, Leased, or Operated
Dale L. and Ella E. Teeple	N75D 34' 24.47"W 568'	N/A	N/A
Roger D. and Patricia A. Hazen	S75d 45' 16.93"W 967'	N/A	N/A
Granville W. and Charlene M. Teeple	S21d 53' 56.41"E 864'	N/A	N/A
Cynthia F. Rowe	N66d 11' 03.82"W 887'	N/A	N/A

HQ

WATERSHED SALT RIVER BROOK

Newfield

HALLIBURTON

Sperry Drilling Services

Project: Wayne County, PA (NAD83)
Site: D.L. Teeple
Well: 1-2H
Wellbore: Wellbore #1
Design: Plan #3
Rig: TBD

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Surface Location:

US State Plane 1983
Pennsylvania Northern Zone
Elevation: WELL @ 0.00ft (TBD)

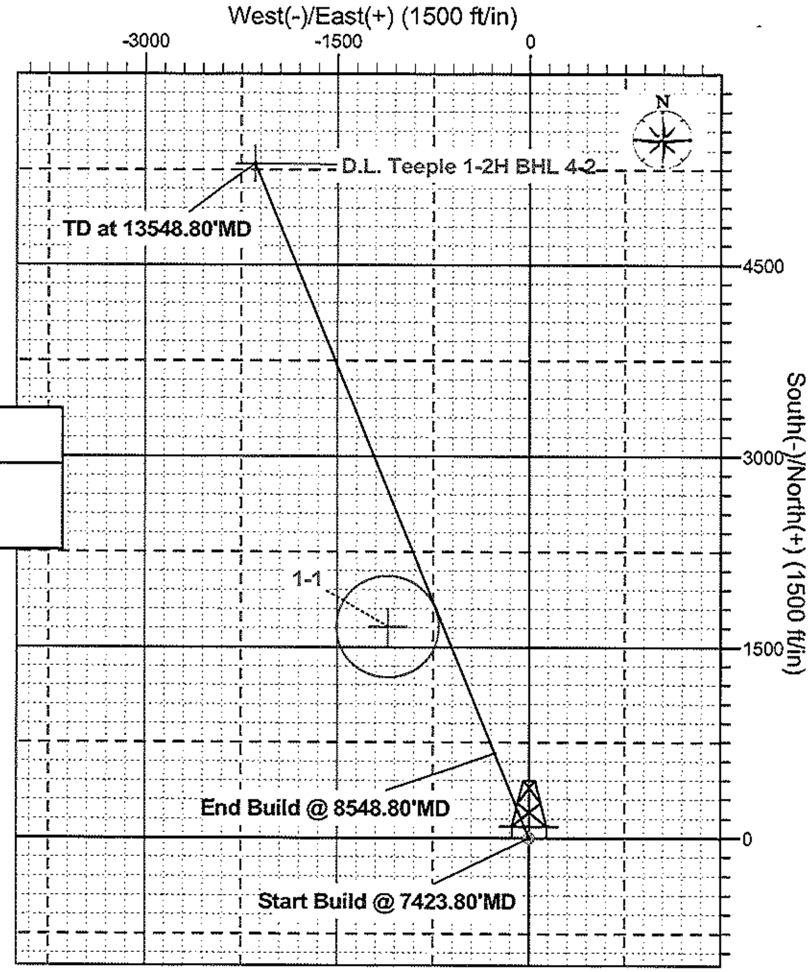
Northing	Easting	Latittude	Longitude
613811.10	2665002.70	41° 49' 23.189 N	75° 11' 39.393 W

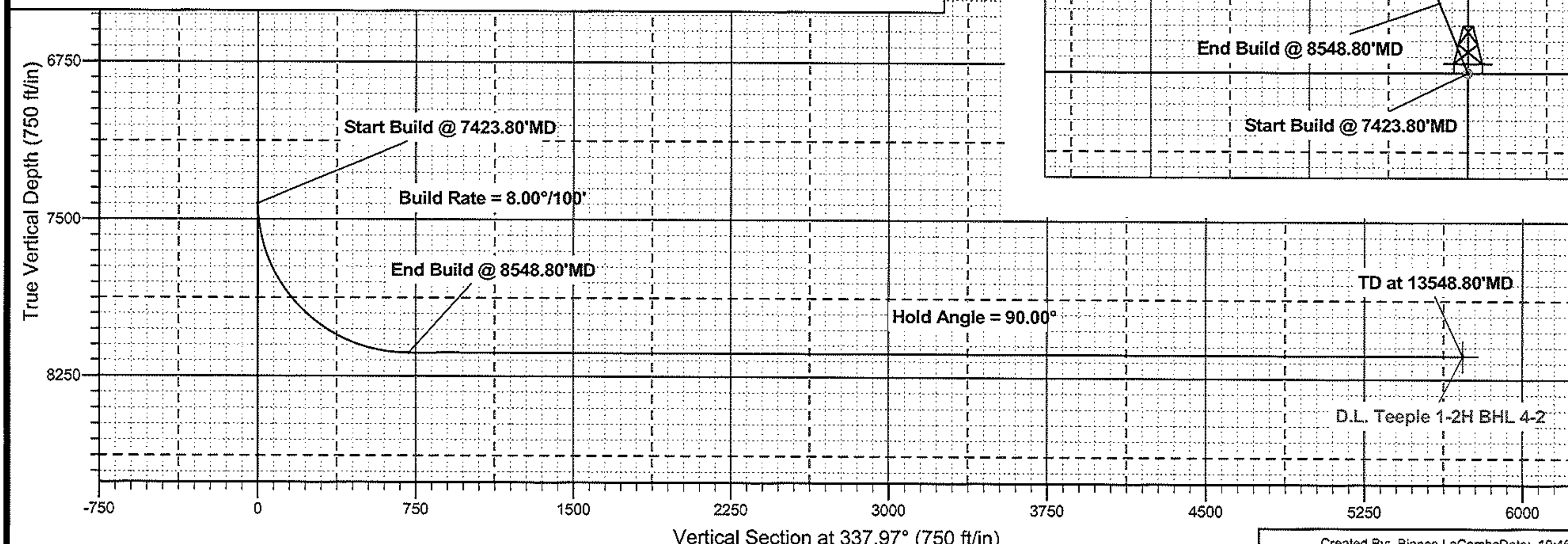
WELLBORE TARGET DETAILS (MAP CO-ORDINATES)

Name	TVD	+N/-S	+E/-W	Northing	Easting	Shape
D.L. Teeple 1-2H BHL 4-2	8140.00	5298.92	-2143.91	619110.02	2662858.79	Point

SECTION DETAILS

MD	Inc	Azi	TVD	+N/-S	+E/-W	DLeg	TFace	VSec	Annotation
0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	
7423.80	0.00	0.00	7423.80	0.00	0.00	0.00	0.00	0.00	Start Build
8548.80	90.00	337.97	8140.00	663.92	-268.62	8.00	337.97	716.20	End Build
13548.80	90.00	337.97	8140.00	5298.92	-2143.91	0.00	0.00	5716.20	TD





Created By: Bianca LaCombeDate: 10:46, April 02 2010

137-20018

5500-PM-OG0002 Rev. 9/2008

pennsylvania
DEPARTMENT OF ENVIRONMENTAL PROTECTION

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
OIL AND GAS MANAGEMENT PROGRAM

WELL LOCATION PLAT

(Attachment, if needed)

DEP USE ONLY	Auth ID #: 127-20018

Use only if you need additional space for listings.

Applicant / Well Operator Name	DEP ID#	Well (Farm) Name	Well #	Serial #
Newfield Appalachia PA LLC	277879	D.L. Teeple	1-2H	

Surface Owner or Water Purveyor with a Water Supply within 1000 feet	Approximate Course and Distance to Water Supply	Owner, Lessee, or Operator of Workable Coal Seam	Name of Coal Seam Owned, Leased or Operated
Cynthia F Rowe	N 66d 11' 3.82" W 866 '	N/A	N/A

DRBC Engagement in Natural Gas Exploration and Development

William J. Muszynski, P.E., Manager
Water Resources Management Branch
Delaware River Basin Commission

Marcellus Shale Meeting
Media, PA
January 19, 2010

Delaware River Basin Commission

Delaware River Basin Commission

- Founded in 1961
- Five Members:
  - Delaware
  - New Jersey
  - Pennsylvania
  - New York State
  - Federal Government

May 19, 2009 Executive Director Determination
Natural Gas Well Activates Within the Drainage Area of SPW

- **Shale formations within the drainage area of SPW**
- **Natural gas well activities (NGWA) covered regardless of DRBC thresholds in RPP and Water Code (WC)**
- **RPP Section 2.3.5.B.6. Water Code Section 3.40**
- **NGWA may not commence without obtaining DRBC approval**

DRBC Role in Natural Gas Activities

1. **Water Withdrawal**
2. **Well Site Activities**
3. **Wastewater Storage, Treatment and Disposal.**

Natural Gas Well Wastewater

Wastewater Generated During Development of the Natural Gas Well

- **Domestic Wastewater**
- **Non-domestic Wastewater**

Domestic Wastewater

Typical sanitary wastewater generally from on-site septic tanks/portable toilets. Likely to be treated at domestic wastewater treatment plants located near natural gas well sites.

Non-Domestic Wastewater

1. Brine generated during well construction.
2. Drilling fluids
3. Flowback from Well Stimulation
   - Vast majority of wastewater generated.
   - 18% to 30% of stimulation fluids used are expected to return as flowback (estimated 2-3 million gallons per well)
   - Flowback contains water, sand, and chemicals used in stimulation process and absorbed from geologic formation.

Non-Domestic Wastewater Characteristics

Characteristics will vary with well site and geologic formation stimulated.

Total Dissolved Solids (TDS) - may potentially contain 2-300,000 mg/l TDS.

Concentrations of metals, chlorides, and organic chemicals.

Levels of radioactivity contributed by the target geologic formation.

DRBC Regulates at the Well Site

Monitoring and characterization of wastewater generated at site.

Storage, tracking, and transportation of wastewater generated.

Disposal of Wastewater

Wastewater Sources and Treatment and Disposal Sites

Sources of non-domestic wastewater and wastewater treatment and disposal can be:

- **Inside of the Delaware River Basin (DRB) Only at DRBC/state approved sites.**

- **Outside of the DRB only at state approved Sites**

In-Basin Non-Domestic Wastewater Treatment Facilities

Currently, there are no DRBC approved non-domestic wastewater treatment facilities.

Only one application in house for approval (DELCORA)

Wastewater treatment facilities must receive DRBC/state approval.

Facility must demonstrate compliance with the more stringent of state or DRBC effluent standards or water quality standards (WQS)

Effluent requirements are set for all domestic or industrial wastewater facilities-technology based

WQS

- Basin wide standards
- In-stream specific standards to protect designated use

Critical Demonstration and Effluent Requirements

1. Total Dissolved Solids (TDS)
2. Acute/Chronic Toxicity (in estuary waters)

Demonstration shall be performed for specific discharge location

TDS *Basin-Wide Standard*

Demonstration that discharge will not exceed 133% of background in stream to receive discharge.

<u>OR</u>

Effluent shall not exceed 1,000 mg/l.

Stream specific – Standards may be more restrictive

Estuary Toxicity Standards

Aquatic Health

Human Health

Location Specific

Radioactivity Standards

Stream Specific WQS for Radioactivity

e.g. Zone 4 – Max. 3 pCi/l alpha emitters
1,000 pCi/l beta emitters

DRBC Review/Decision Process

Receipt of Application for Project

Notice to Interested Parties (IP's)

Development and Review of Draft Docket or Recommendation to DRBC Commissioners

Public Notice

- **Generally 10-days prior to Commission hearing of docket**
- **Includes notice to IP's**

Commission Public Hearing

Appeal Provisions

Check in with the Commission early in the process:

Water Resources Management Branch
Project Review Section
Chad Pindar
David Kovach
Eric Engle
609-883-9500 ext. 216

Regulations and applications are available on the Commission's website:

www.drbc.net

Delaware River Basin Commission

Thank you.

Delaware River Basin Commission

Vision Statement

CHARTING THE FUTURE

PREAMBLE

The Delaware River Basin Commission was formed in 1961 by the signatory parties to the Delaware River Basin Compact (Delaware, New Jersey, New York, Pennsylvania, and the United States) to share the responsibility of managing the water resources of the Basin. Since its formation, the Commission has provided leadership in restoring the Delaware River and protecting water quality, resolving interstate water disputes without costly litigation, allocating and conserving water, managing river flow, and providing numerous other services to the signatory parties. The success of the past serves as a promise for the future as the Commission and the region move into the 21st century. In implementing the Compact, we will be guided by our Vision, Mission and Core Values.

VISION OF THE DELAWARE RIVER BASIN COMMISSION

The Commission will be the leader in protecting, enhancing, and developing the water resources of the Delaware River Basin for present and future generations. In performing this leadership role, the Commission will serve as a policy-maker, regulator, planner, manager and mediator on behalf of the Signatories to the Delaware River Basin Compact and the citizens of the Basin.

MISSION

We will:

- **Provide comprehensive watershed management.**
- **Act as stewards of the Basin's water resources particularly with respect to:**
  - **Surface water quality, including both point and nonpoint sources of pollution;**
  - **Ground and surface water quantity, including water demands, water withdrawals, water allocations, water conservation, and protected areas;**
  - **Drought management; and**
  - **In-stream flow management**
- **Promote effective inter-agency coordination to prevent duplication of efforts.**
- **Seek increased public involvement.**

By:

- **Serving primarily basinwide and interstate interests; and national, statewide, regional, and local watershed interests as the need arises.**
- **Resolving interstate disputes through mediation.**
- **Regularly updating the Comprehensive Plan.**
- **Adopting and implementing policies to manage the Basin's water resources in an integrated, planned fashion.**
- **Integrating environmental and economic needs.**
- **Basing decisions on sound science.**
- **Providing meetings, conferences, seminars, and other opportunities for public education, information exchange, involvement, and resolution of issues.**

CORE VALUES

We believe in:

- **Serving the public.**
- **Treating everyone with fairness and respect.**
- **Acting in an open, honest and professional manner.**
- **Listening and responding to our constituents.**
- **Encouraging innovative, creative solutions to water management problems.**
- **Improving our expertise.**
- **Enjoying and respecting the magnificent resource that is the watershed of the Delaware River.**

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DRBC Home Page

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Recommendations for Pennsylvania's Proposed Changes to Oil and Gas Well Construction Regulations

Report to:

Earthjustice and Sierra Club

Prepared by:

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Oil & Gas, Environmental, Regulatory Compliance, and Training

March 1, 2010

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Contents

1. Introduction

This analysis responds to a request by Earthjustice and Sierra Club for a review of proposed revisions to the Pennsylvania's regulations governing construction of oil and gas wells [25 Pa.Cod Ch. 78 (Chapter 78)]. The purpose of this review is to examine whether the revisions proposed by the Pennsylvania Department of Environmental Protection (DEP or the Department) are: best practice, protective of human health and the environment, and consistent with DEP's stated goals of: (1) minimizing public concerns associated with gas migration into public drinking water supplies; (2) updating material specifications and performance testing requirements; and (3) revising design, construction, operations, monitoring, plugging, water supply replacement, and gas migration reporting requirements.

Analysis Approach

This analysis examined DEP's proposed changes to Chapter 78 and makes recommendations on whether those proposed changes are best practice and protective of human health and the environment. Additionally, this analysis examined sections of Chapter 78 that DEP did not propose to amend in order to identify further changes that would serve to achieve DEP's stated goals.

Recommendations made in this report are based on 23 years of experience as a Petroleum and Environmental Engineer and are highlighted in blue text boxes.

2. Subchapter A, General Provisions, Definitions § 78.1

Casing Seat. DEP has revised the definition to read:

> *"The depth to which the surface casing or coal protection casing or intermediate casing is set. In wells without surface casing, the casing seat shall be equal to the depth of casing which is typical for properly constructed wells in the area."*

The second sentence in this definition is not consistent with standard industry practice for construction of an oil and gas well. Surface casing, and in some cases an additional string of intermediate casing is used to protect ground water aquifers, provide the structure to support blowout prevention equipment, and provide a conduit for drilling fluids when drilling the subsequent section of the well. The second sentence of this definition should be deleted, or DEP should explain how an oil and gas well could be drilled safely, and protect ground water resources, without surface casing.

> **Recommendation No. 1**: Delete the second sentence of the proposed casing seat definition.

Surface Casing. DEP has revised the definition to read:

> *"Casing used to isolate the wellbore from fresh groundwater and to prevent the escape or migration of gas, oil and other fluids from the wellbore into fresh groundwater. The surface casing is also commonly referred to as the water string or water casing."*

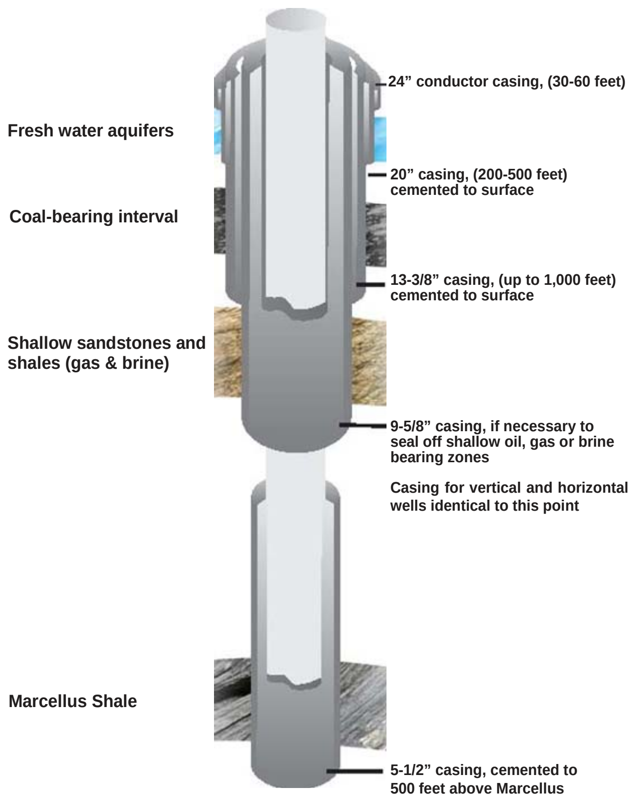
In addition to protecting ground water, surface casing also provides the very important structural support required to install blowout prevention equipment and provides a conduit for drilling fluids when drilling the subsequent section of the well.

Recommendation No. 2: The surface casing definition should clarify that the surface casing also provides the structural support required to install blowout prevention equipment and provides a conduit for drilling fluids when drilling the subsequent section of the well.

Intermediate Casing. DEP has added a new definition that reads:

> *"A string of casing other than production casing that is used in the wellbore to isolate, stabilize or provide well control to a greater depth than that provided by the surface casing or coal protection casing."*

Generalized casing design for a Marcellus Shale gas well to protect the environment



Intermediate casing does play an important role in the structural stability of the wellbore, but it also provides a very important additional protective barrier of pipe and cement across shallow freshwater aquifer zones. In other words, it provides a second protective barrier, in addition to the surface casing and cement, when a well passes through a fresh water aquifer.

Intermediate casing may be set to provide a transition from the surface casing to the production casing for protection of oil, gas, and freshwater zones, and to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. A drilling engineer may need to set hundreds or thousands of feet of intermediate casing to: isolate unstable hole sections (to prevent collapse); isolate high or low pressure zones; isolate geologic "thief" zones prone to robbing mud from the well bore (lost circulation); put gas or saltwater zones behind pipe before drilling into the production zone; or provide additional wellbore structure. Intermediate casing is typically set prior to drilling through the hydrocarbon-bearing zone, and may be cemented behind the entire casing string from the top of the well to the bottom of the casing shoe if the intermediate casing depth is shallow enough.

Recommendation No. 3: The intermediate casing definition should clarify that intermediate casing also provides a very important additional protective barrier of pipe and cement across shallow freshwater aquifer zones, and provides a transition from the surface casing to the production casing for protection of oil, gas, and freshwater zones, and to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards.

Casing Use Requirement. DEP's regulations at Chapter 78, and definitions at § 78.1, provide latitude in the amount and type of surface casing that can be run. Yet, industry trade groups operating in Pennsylvania recognize the importance of running both surface casing and intermediate casing in areas where freshwater resource protection is of critical importance, to provide a sound structural barrier that contains stimulation fluids when conducting large slickwater fracture treatments (e.g. Marcellus Shale).

For example, a typical wellbore diagram[1] of the casing program recommended by the oil and gas industry and industry trade groups operating in the Marcellus Shale in Pennsylvania[2] is shown on the previous page. Industry recommends three sets of casing (conductor, surface, and intermediate), all cemented to the surface, which puts freshwater behind three layers of casing and cement. Industry also recommends a fourth layer of production casing.

> **Recommendation No. 4**: Consistent with the recommendations of industry trade groups operating in Pennsylvania, DEP regulations should require the use of ***surface*** casing ***and intermediate*** casing in areas where freshwater resource protection is of critical importance. Casing and cement barriers also provide a sound structural barrier that contains stimulation fluids when conducting large slickwater fracture treatments.

Cement. DEP's current definition for cement reads:

> *"A mixture of materials for bonding or sealing that attains a 7-day maximum permeability of 0.01 millidaricies and a 24-hour compressive strength of at least 500 psi in accordance with applicable API standards and specifications."*

DEP's definition for cement sets a 24-hour compressive strength standard of at least 500 psi; however, other states, such as Texas, have found that standard insufficient to prevent vertical migration of fluids or gas behind pipe. Texas requires operators to have knowledge of the location and extent of all usable-quality water zones, and requires a higher cement quality to protect these zones. For example, Texas requires an **additional** 72-hour compressive strength standard of at least 1,200 psi across critical zones of cement. For example, Texas regulations define the critical zone as "all usable-quality water zones," and define the "critical zone of cement" as the bottom 20% of the casing string (at least 300', but no more than 1000').[3] This places a section of high strength cement at the bottom of the casing seat where the highest pressures and stresses are likely to be encountered.

Additionally, Texas requires the API free water separation to average no more than six milliliters per 250 milliliters of cement, tested in accordance with the current API RP 10B. The Texas commission[4] overseeing oil and gas development may require a better quality of cement mixture to be used in any well or any area if evidence of local conditions (which must be provided by the permit applicant) indicates a better quality of cement is necessary to prevent pollution or to provide safer conditions in the well or area.

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[1] http://www.pamarcellus.com/images/pdfs/casing_graphic-with_copy.pdf.
[2] http://www.pamarcellus.com/about.php. "Founded in 2008, the Marcellus Shale Committee is an organization committed to the responsible development of natural gas from the Marcellus Shale geological formation in Pennsylvania and the enhancement of the Commonwealth's economy that can be realized by this clean-burning energy source. The members of the committee bring the strength of the Pennsylvania Oil and Gas Association and the Independent Oil and Gas Association of Pennsylvania together to address concerns with regulators, government officials and the people of the Commonwealth about all aspects of drilling and extracting natural gas from the Marcellus Shale formation."
[3] 16 TAC Part 1.
[4] Texas Railroad Commission

Texas cement quality standards read:

"Surface casing strings must be allowed to stand under pressure until the cement has reached a compressive strength of at least 500 psi in the zone of critical cement before drilling plug or initiating a test. The cement mixture in the zone of critical cement shall have a 72-hour compressive strength of at least 1,200 psi. … In addition to the minimum compressive strength of the cement, the API free water separation shall average no more than six milliliters per 250 milliliters of cement tested in accordance with the current API RP 10B. The commission may require a better quality of cement mixture to be used in any well or any area if evidence of local conditions indicates a better quality of cement is necessary to prevent pollution or to provide safer conditions in the well or area.[5]

"Compressive strength tests. Cement mixtures for which published performance data are not available must be tested by the operator or service company. Tests shall be made on representative samples of the basic mixture of cement and additives used, using distilled water or potable tap water for preparing the slurry. The tests must be conducted using the equipment and procedures adopted by the American Petroleum Institute, as published in the current API RP 10B. Test data showing competency of a proposed cement mixture to meet the above requirements must be furnished to the commission prior to the cementing operation. To determine that the minimum compressive strength has been obtained, operators shall use the typical performance data for the particular cement used in the well (containing all the additives, including any accelerators used in the slurry) at the following temperatures and at atmospheric pressure. (i) For the cement in the zone of critical cement, the test temperature shall be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of the zone of critical cement. (ii) For the filler cement, the test temperature shall be the temperature found 100 feet below the ground surface level, or 60 degrees Fahrenheit, whichever is greater.[6]*"*

Recommendation No. 5: Revise the cement definition to include a 72-hour compressive strength standard of 1,200 psi for cement mixtures in the zone of critical cement. Also, require conformance with the API free water separation standard of no more than six milliliters per 250 milliliters of cement tested in accordance with the current API RP 10B. Provide a provision for the Department to set more stringent local standards if needed for pollution prevention, and establish quantitative temperature limits for water used in cement mixing. The cement definition should clarify that it applies to cement used for surface, intermediate, and production casing.

Cement Ticket. DEP's has added a new definition that reads:

"Cement ticket – A written record that documents the procedures and specifications of the cementing operation and the chemical composition of the cement for each cemented casing string. The record shall include the amount and composition of the cement slurry, the amount of cement returned to the surface, if any, the amount and type of additives to the cement slurry mixture. Slurry properties must include weight, yield, density, water requirements, compressive strength, fluid loss. Cementing operation information shall include a description of the stages and sequence of events during the cementing operation, calculations employed, and wellbore and casing information such as casing diameter and depth and hole size and depth and pump time."

[5] 16 TAC Part 1 §3.13(b)(2)(C)
[6] 16 TAC Part 1 §3.13(b)(2)(D)

DEP's recommendation to add a new definition for cement ticket is useful. However, it is recommended that the definition be expanded to include the recommendations listed below.

Recommendation No. 6: Expand the cement ticket definition to include: (a) a requirement for the operator to test the mixing water pH and temperature and note it on the cement ticket (this is standard industry practice and aids in determining cement quality); (b) a record of the Waiting on Cement [WOC] time, which is the time required to achieve the calculated compressive strength standard before the casing is disturbed in any way [described in the cement definition comments above]; and (c) a certification statement that requires the operator to certify, under penalty of law, that the cement job was completed in compliance with Pennsylvania regulatory requirements.

3. Subchapter C, Environmental Protection, Performance Standards, Protection of Water Supplies, § 78.51

DEP has proposed a number of important revisions to the regulations at § 78.51 to clarify what constitutes an adequately restored or replacement water supply. However, DEP did not recommend any revisions to the portion of § 78.51(c) that sets a timeframe for acting upon a complaint filed by a landowner, water purveyor, or affected person suffering pollution or diminution of a water supply as a result of drilling, altering, or operating an oil or gas well. DEP's regulations at § 78.51(c) currently allow a delay of up to 10 calendar days before an investigation must be completed.

If a violation of DEP standards is suspected, and that violation results in pollution or diminution of a water supply, or has the potential to threaten a water supply, immediate investigation by DEP is essential, not merely response within a 10-day time period. It is recommended that this regulation be revised to require an immediate investigation to commence within 24 hours of notification, and that if DEP's investigation team finds evidence to support the complaint, the noncompliant activity should be immediately shut down. Additionally, all potentially affected users of the water supply should be immediately notified and provided alternative water supplies until the DEP completes a final investigation and a final remedy is resolved with the non-compliant operator. Keep in mind that most wells take 14 - 30 days to drill, depending on depth; and depending on where the operator is within the drilling cycle when the problem begins, drilling rig operations could be completely packed up and moved off location before a DEP investigation team arrives on the site 10 days later. The same holds true for stimulation procedures such as fracture treatments that may take a few hours to a few days, depending on the number of stages and complexity.

It is unlikely that the operator or equipment will be on location, or any evidence can be examined or collected by an investigation team, 10 days after a report of a violation is made. Most importantly, if the agency is notified of a threat to a water supply, immediate action is necessary. A technical team should be sent out into the field without delay to examine the situation and determine whether action is needed to shut down operations. That same initial investigation team can collect the information, records, and evidence required to complete the formal written determination due in at least 45 days.

Recommendation No. 7: Revise § 78.51(c) to read: Within 24 hours of the receipt of the investigation request, the Department will send a technical team to the field site to examine the situation and determine whether immediate action is needed to shut down operations. The technical team will also collect the information, records, and evidence required to complete the investigation. If the technical team finds that there is any potential threat or impact to a water supply, the operator will be ordered to immediately cease operations, and the Department will immediately notify all potential affected users of the water supply and require the operator to provide alternative water supplies until the Department completes a final investigation and a final remedy is resolved with the non-compliant operator.

Within 45 days of receipt of the investigation request, the Department will issue a formal written determination. If the Department finds that pollution or diminution was caused by drilling, alteration, or operation activities, or if it presumes the well operator responsible for polluting the water supply of the landowner or water purveyor under section 208(c) of the act (58 P. S. § 601.208(c)), the Department will issue orders to the well operator necessary to assure compliance with this section.

DEP proposes to add a new requirement at § 78.51(i) that requires a well operator to notify DEP if a water supply contamination complaint has been received from a landowner, water purveyor, or affected person, within 10 calendar days. A 10-day notification period is too long. Notification should be made within 24 hours, followed by a written report via electronic communication or facsimile within a 24-hour period. This way the DEP is promptly notified and can send a technical team to the site to commence the investigation while the factors that may have contributed to the complaint are still present.

Recommendation No. 8: Revise the notification period in § 78.51(i) to 24 hours.

DEP proposes a new regulation § 78.51(e) that clarifies what constitutes an adequate restoration or replacement of a polluted water supply. This regulation is useful. However, the new language proposed for § 78.51(e)(2) appears to include redundant language, as well as language somewhat contradictory to the existing §78.51(d) regulation. It is recommended that these regulatory sections be combined and clarified.

The language proposed at § 78.51(e)(2) could allow an operator to construct a new, replacement water supply at a standard less than the Pennsylvania Safe Drinking Water Act if it were replacing a water source that originally did not meet the Pennsylvania Safe Drinking Water Act. All newly constructed water sources, especially those constructed to remedy a compliance violation, should meet the minimum water quality standards of the Pennsylvania Safe Drinking Water Act.

Recommendation No. 9: Revise § 78.51(e)(2) and § 78.51(d) to meet this stated intent: All ***restored*** water supplies must be at least equal to the quality of the water supply before it was affected by the operator. If the quality of the water supply, before it was affected by the operator, cannot be affirmatively established, the operator shall demonstrate that the concentrations of substances in the restored water supply meet the Pennsylvania Safe Drinking Water Act standards. Any new, ***replacement*** water supply must meet the Pennsylvania Safe Drinking Water Act standards.

4. Subchapter C, Environmental Protection, Performance Standards, Predrilling or Prealteration Survey, § 78.52

DEP regulations allow an operator to obtain water supply samples prior to drilling. The purpose of this "baseline" water quality assessment is to establish whether pollution already exists. The right to conduct the sampling is described in § 78.52(a). DEP's sampling instructions are found at § 78.52(c):

> *"(c) The survey shall be conducted by an independent certified laboratory. A person independent of the well owner or well operator, other than an employee of the certified laboratory, may collect the sample and document the condition of the water supply, if the certified laboratory affirms that the sampling and documentation is performed in accordance with the laboratory's approved sample collection, preservation and handling procedure and chain of custody."*

The sampling instructions at § 78.52(c) do not specify what type of tests must be completed, when the testing must be completed, or what testing procedures must be followed. A standard suite of water quality tests and procedures should be specified and required by DEP. Baseline testing should be completed over a full hydrologic cycle (multiple samples). Additionally, in areas where industrial activity has already occurred; testing should include examination of chemicals used by the oil and gas industry. See additional recommendations on this topic at § 78.122(b)(6).

DEP's reporting instructions are found at § 78.52(e):

> *" (e) The report describing the results of the survey must contain the following information:*
>
> *(1) The location of the water supply and the name of the surface landowner or water purveyor.*
>
> *(2) The date of the survey, and the name of the certified laboratory and the person who conducted the survey.*
>
> *(3) A description of where and how the sample was collected.*
>
> *(4) A description of the type and age, if known, of the water supply, and treatment, if any.*
>
> *(5) The name of the well operator, name and number of well to be drilled and permit number if known.*
>
> *(6) The results of the laboratory analysis."*

The reporting instructions at § 78.52(e)(6) are very generic. DEP only requests the "results of the laboratory analysis" to be provided with no clear instructions on what tests must be reported, at a minimum, or what test methods must be followed, along with evidence that quality control and quality assurance procedures were followed.

The report should include a summary, in layman's terms, verifying whether any contamination was found. If contamination was found, the report should clearly describe the amount of contamination found and by what factor it exceeds Pennsylvania's Safe Drinking Water Act.

This report should be made available to the public, and should be provided to all agencies responsible for ground water protection (e.g. county boards, commissions).

Additionally, DEP should require annual water quality testing (at a minimum) to verify the water supply condition while drilling, completion and production operations continue.

Recommendation No. 10: Revise the sampling instructions at § 78.52(c) to specify the type of tests and testing procedures that must be followed, and when samples must be obtained. A minimum standard suite of water quality tests and procedures should be required. Baseline testing should be completed over a full hydrologic cycle (multiple samples). In areas where industrial activity has already occurred, testing should include examination of chemicals used by the oil and gas industry. Revise the reporting instructions at § 78.52(e)(6) to ensure the report includes: test results; test methods; evidence that quality control and quality assurance procedures were followed; a summary, in layman's terms, verifying whether any contamination was found. If contamination was found, the report should clearly describe the amount of contamination found and by what factor it exceeds Pennsylvania's Safe Drinking Water Act. Require the test reports to be made available to the public, and to be provided to all agencies responsible for ground water protection (e.g. county boards, commissions). Require annual water quality testing (at a minimum) to verify the water supply condition while drilling, completion and production operations continue.

5. Subchapter C, Environmental Protection, Performance Standards, Control and Disposal Plan, § 78.55

DEP did not propose any changes to § 78.55; however, it is recommended that a revision be made to require operators to submit their control and disposal plans to DEP for review and approval. Currently, the plans are prepared by the operator, but there is no agency review for compliance with Pennsylvania Environmental Protection Standards.

Recommendation No. 11: Revise § 78.55 to require well operators to submit a copy of their control and disposal plan for DEP review and approval prior to commencing operations to ensure compliance with Pennsylvania Environmental Protection Standards.

6. Subchapter D, Well Drilling, Operation and Plugging, Use of Safety Devices, Well Casing, § 78.71

DEP proposes to revise § 78.71 (a) to read:

> *"(a) The operator shall equip the well with one or more strings of casing of sufficient cemented length and strength to prevent blowouts, explosions, fires and casing failures during installation, completion and operation."*

DEP's stated goal of revising the well casing requirements to enhance ground water protection and to minimize public concerns associated with gas migration into public drinking water supplies is not reflected in the regulations at § 78.71(a).

Recommendation No. 12: Amend § 78.71(a) to clearly state that sufficient casing and cement must be installed in the well to prevent contamination of ground water resources, in addition to the other purposes already listed.

7. Subchapter D, Well Drilling, Operation and Plugging, Use of Safety Devices, Blowout Equipment, § 78.72

A Blowout Preventer (BOP) cannot be installed until surface casing is set and cemented; therefore a gas flow diverter system should be installed to provide for personnel and public safety during the initial stages of well drilling and setting surface casing. Once surface casing is set, a BOP can be installed to control the well as it is drilled deeper into higher pressure zones. The proposed DEP regulations do not set standards for diverter systems, except later, at § 78.73, which states that excess gas encountered during drilling should be diverted away from the drilling rig in a manner that does not create a hazard to public health or safety. Yet, DEP provides no criteria or standards for what constitutes an acceptable design for a drilling diverter system. Shallow gas hazards are well known in the oil and gas industry to be the root cause of many well blowouts and explosions. Many of these situations could have been prevented by a more rigorous diverter system design. It is recommended that DEP improve the safety device regulations at § 78.72 to include diverter system specifications.

Recommendation No. 13: It is recommended that DEP improve the safety device regulations at § 78.72 to add the following diverter system specifications.

A diverter system should be at least as large as the diameter of the hole that will be drilled, and the system should include a remotely operated annular pack-off device, a full-opening vent line valve, and a diverter vent line with a diameter appropriately sized for geological conditions, rig layout, and surface facility constraints.

The diverter vent line outlet should be located below the annular pack-off device, either as an integral part of the annular pack-off device or as a vent-line outlet spool immediately below it. The actuating mechanism for the vent line valve should be integrated with the actuating mechanism for the annular pack-off device in a fail-safe manner so that the vent line valve automatically opens before full closure of the annular pack-off device. The diverter system vent line should extend at least 100 feet away from any potential sources of ignition and the drilling rig substructure, and should be secured. The diverter system area should be well marked as a "warning zone" at the vent line tip, prohibiting ignition sources, equipment, or personnel in this area.

DEP has revised the applicability standard of § 78.72 to specify the types of wells that are required to install a BOP when drilling. The proposed applicability standard includes four criteria:

1. Marcellus Shale gas wells;
2. wells where an operator anticipates pressures or flows that may result in a blowout;
3. wells drilled in areas where there is no previous pressure data; and
4. wells regulated by the Oil and Gas Conservation Law.

Criteria #1 & #3 are clear. BOPs are required on all Marcellus Shale gas wells and all wells drilled in areas where there is no previous pressure data.

Criterion #2 provides the operator with broad discretion to determine whether wellhead pressures or natural open flows that may occur during drilling operations could pose a threat of blowout. There are no safety or hazard criteria established to guide the operator as to when a BOP is required.

Criterion #4 is clear in that it requires BOPs on all wells regulated by the Oil and Gas Conservation Law, but that law excludes wells that do not penetrate the Onondaga horizon. The law also excludes wells that do not exceed a depth of 3,800 feet beneath the surface, including wells located in areas where the Onondaga horizon is nearer to the surface than 3,800 feet. Therefore, it is not clear if Criterion #4 conflicts with Criteria #1, #2 or #3.

Industry standard practice is to design, size, and install a BOP to handle wellhead pressures expected to be encountered while drilling (with a sufficient safety factor). Operators that propose to drill wells without BOPs should provide a technical and safety justification to DEP as part of their permit to drill application. This justification should be reviewed and approved by the Department. A BOP should be required on all wells, and BOP waivers should be the exception rather than the rule.

Blowouts are very serious human health, work safety, and environmental situations. Blowouts may result in human injury, fire, explosion, oil spills, gas venting, equipment damage, etc.

Recommendation No. 14: Revise § 78.72 to require all wells to be drilled with a BOP once surface casing is installed and cemented. Allow exceptions to that rule only if the operator submits a sufficient technical and safety justification to warrant drilling without a BOP.

The operator should be required to submit a copy of its blowout preventer (BOP), diverter, and related equipment plans, along with its proposed casing and cementing design plan, to DEP for review and approval, as part of permit to drill applications.

DEP regulations at § 78.72 do not specify the type of BOPs required. Typically for rotary drilling operations with a maximum potential surface pressure of 3,000 psi or less, the BOP must have at least three preventers, including: one equipped with pipe rams that fit the size of the drill pipe, tubing, or casing that is being used; one with blind rams; and one annular type. In rotary drilling rig operations with a maximum potential surface pressure of 3,000 psi or greater, the BOP typically has at least four preventers, including: two equipped with pipe rams that fit the size of the drill pipe, tubing, or casing that is being used; one with blind rams; and one annular type.

Regulations typically specify that the rated working pressure of the BOP and other well control equipment must exceed the maximum potential surface pressure to which it may be subjected. Interestingly, existing DEP regulations at § 78.72 (c) require operators to select the appropriate pressure rating for all pipe fittings, valves, and other connections to the BOPS, but DEP's regulations do not specify that the BOPs themselves must be capable of withstanding the maximum potential surface pressure to which it may be subjected. BOPs come in various sizes and pressure ratings. Larger, higher-pressure rated BOPs are more expensive to purchase and operate; therefore, it is important that this point be specified in regulation.

Recommendation No. 15: Revise § 78.72 to provide specific BOP type and pressure rating criteria.

DEP proposes a new requirement at § 78.72 (c) that reads:

> *"(c) The controls for the blow-out preventer shall be accessible to allow actuation of the equipment in the event of an emergency. Controls for a blow-out preventer with a pressure rating of greater than 3,000 psi should be located a safe distance from the drilling rig."*

This regulation requires BOP controls to be accessible during an emergency; this is logical. However, the second sentence of the proposed regulation, which instructs the operator to place the BOP controls at a safe distance away from the drilling rig, does not instruct the operator to have BOP controls on the rig itself. BOP controls need to be accessible **both** on the rig and at a location a safe distance away from the drilling rig.

> **Recommendation No. 16**: DEP regulations at § 78.72(c) should be revised to clarify that BOP controls are also needed on the rig.

DEP regulations at § 78.72(d) and (e) require BOPs to be tested; however, the regulations do not specify that a "pass" rate is required to continue drilling operations, although this is surely DEP's intent. It would be useful to clarify that drilling operations must cease if a BOP fails a test. The BOP must be repaired or replaced, and successfully retested, prior to resuming drilling.

> **Recommendation No. 17**: DEP regulations at § 78.72(d) and (e) should be revised to clearly state that drilling operations must cease if a BOP fails a test. The BOP must be repaired or replaced, and successfully retested, prior to resuming drilling.

8. Subchapter D, Well Drilling, Operation and Plugging, General Provisions for Well Construction and Operation, § 78.73

DEP proposes a more stringent casing pressure limitation in the new regulations at § 78.73(c), by adding an additional safety factor, and by expanding that safety factor to include protection at the intermediate casing seat, in addition to the surface casing seat. Both changes are safety and environmental improvements. DEP proposes § 78.73(c) to read:

> *"(c) After a well has been completed, recompleted, reconditioned or altered the operator shall prevent shut-in pressure and producing back pressure at the surface casing seat, coal protective casing seat or intermediate casing seat when the intermediate casing is used in conjunction with the surface casing to isolate fresh groundwater from exceeding 80 percent (80%) of the hydrostatic pressure of the surrounding fresh groundwater system in accordance with the following formula. The maximum allowable shut-in pressure and producing back pressure to be exerted at the casing seat may not exceed the pressure calculated as follows: Maximum pressure = (0.8 x 0.433 psi/foot) multiplied by (casing length in feet)."*

The proposed regulation applies to wells **after** they have been "completed, recompleted, reconditioned or altered." While it is understandable that this requirement does not apply while drilling, casing, and cementing are underway, it is important to clarify that this requirement will be in place during any testing, stimulation, or other well operations.

Most drilling is completed using overbalanced drilling fluid systems of sufficient density to counteract any potential hydrostatic pressures in the wellbore; therefore, it would not be possible to adhere to the proposed pressure limits during these operations. However, once the drilling is "completed" and the casing is set and cemented in place, the pressure limitation should apply to all subsequent operations to protect ground water resources.

The term "completion" is often more broadly defined by industry to include casing, cementing, and well stimulation operations. The regulation should be clear that the pressure limitation will apply to testing and stimulation treatments, and other well operations, because high pressure is exerted on the casing seat during these operations.

Recommendation No. 18: DEP regulations at § 78.73 (c) should be revised to make it clear that the pressure limit will apply to all well activities after the casing is cemented in place.

DEP's revised regulation at § 78.73(d) requires the operator to take action to prevent the migration of gas and other fluids from lower formations into fresh groundwater in the event that the hydrostatic pressure exceeds the newly proposed 80% safety factor, described in § 78.73(c). Requiring the operator to take action in the event that the hydrostatic pressure was exceeded is a good step; yet, the proposed regulations do not provide any instruction on what course of action is required to remedy mechanical defects in the wellbore construction, nor does it require the operator to notify the DEP of the problem, report the resolution, or notify anyone who may be potentially affected (e.g. by groundwater impacts).

Recommendation No. 19: DEP regulations at § 78.73(c) should be revised to require the operator to notify DEP of any pressure exceedance within 24 hours, followed by a written plan of action to be submitted to DEP for review and approval. The regulations should also include a requirement for the operator to work with DEP to notify any potentially affected parties.

DEP proposes a new regulation at § 78.73(e) that requires operators to ensure that excess gas encountered during drilling, completion, or stimulation be flared, captured, or diverted away from the drilling rig in a manner that does not create a public health or safety hazard. The proposed regulation does not mandate or encourage operators to select the most environmentally preferable, lowest impact methods available. While flaring and venting have been commonly used in the oil and gas industry to deal with unwanted, potentially explosive vapors, both federal and state governments have taken steps over the past two decades to enact regulations that limit flaring and venting of natural gas.[7] Initially, the motive was to conserve hydrocarbon resources to maximize federal and state revenue and gas supply. More recently, focus on greenhouse gas (GHG) emission reduction has prompted additional innovation to further reduce flaring and venting. Reducing flaring and venting to the lowest level technically achievable is widely considered best practice.

Drilling & Completions: Flares may be used during well drilling, completion, and testing to safely combust hydrocarbon gases that cannot be collected because gas processing and pipeline systems have not yet been installed. If gas processing equipment and pipeline systems are in place, gas flaring can be avoided in all cases except equipment malfunction.

During the drilling and completion phase of the first well on a well pad, a gas pipeline may not be installed. Gas pipelines are typically not installed until it is confirmed that an economic gas supply is found. Therefore, gas from the first well is often flared or vented during drilling and completion activities because there is not a pipeline to route it to. However, subsequent wells drilled on that same pad would be in a position to implement Reduced Emission Completion (REC), also called "green completion," which involves routing gas to a pipeline. Green completions require equipment to be brought to the well site to process wet gas from the well (during well completion activities) to ensure the gas meets pipeline specifications.

Gas Production: High pressure gas buildup may require gas venting via a pressure release valve, or gas may need to be routed to a flare during an equipment malfunction. At natural gas facilities, continuous flaring or venting may be associated with the disposal of waste streams[8] and gaseous by-product streams[9]

[7] Global Gas Flaring Reduction Partnership (GGFR), Guidance on Upstream Flaring and Venting Policy and Regulation, Washington D.C., March 2009.
[8] For example, acid gas from the gas sweetening process and still-column overheads from glycol dehydrators.

that are uneconomical to conserve.[10] Venting or flaring may also occur during manual or instrumented depressurization events, compressor engine starts, equipment maintenance and inspection, pipeline tie-ins, pigging, sampling activities, and removal of hydrates from pipelines.[11]

Best practices for flaring and venting during gas production should limit flaring and venting to the smallest amount needed for safety. Gas should be collected for sale, used as fuel, or reinjected for pressure maintenance, unless it is proven to be technically and economically unfeasible.

DEP should adopt very clear regulations limiting flaring and venting during gas production operations. If gas collection, use, sale, or reinjection is not possible, DEP should require operators to flare gas as a preferred method over venting. Gas flaring is environmentally preferable over venting because flaring reduces hazardous air pollutants, volatile organic compound emissions, and GHG emissions.[12]

Several states (e.g. Alaska and California) require operators to keep accurate records of gas venting and flaring to ensure that the amount is limited to safety related needs. Some states and the federal government (in the Outer Continental Shelf) require operators to pay royalty and taxes on flared and vented gas not authorized for safety purposes. This encourages investment in gas collection and control devices to conserve natural gas.[13]

Best Practices for Flares: When flare use is necessary for safety, the following best practices should be instituted:

- Minimize the risk of flare pilot blowout by installing a reliable flare system;
- Ensure sufficient exit velocity or provide wind guards for low/intermittent velocity flare streams;
- Ensure use of a reliable ignition system;
- Minimize liquid carry over and entrainment in the gas flare stream by ensuring a suitable liquid separation system is in place; and
- Maximize combustion efficiency by proper control and optimization of flare fuel/air/steam flow rates.

Best Practices for Venting and Fugitive Emissions: Best Practices for controlling venting and fugitive emissions include:

- Leak Detection and Repair (LDAR) programs, including acoustic detectors and infrared technology to detect odorless and colorless leaks;
- Use of low bleed pneumatic instruments,[14] and use of instrument air, electric or solar powered control devices;
- Use of dry centrifugal compressor seals;
- Use of smart automation plunger lifts for liquid unloading;
- Early installation of pipelines; and
- REC methods for gas well completions.

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[9] For example: instrument vent gas; stabilizer overheads; and process flash gas.

[10] The Global Gas Flaring Reduction partnership (GGFR) and the World Bank, Guidelines on Flare and Vent Measurement, September 2008.

[11] The Global Gas Flaring Reduction partnership (GGFR) and the World Bank, Guidelines on Flare and Vent Measurement, September 2008.

[12] Fugitive and Vented methane has 21 times the global warming potential as combusted methane gas. Methanetomarkets.org, epa.gov/gasstar.

[13] Global Gas Flaring Reduction Partnership (GGFR), Guidance on Upstream Flaring and Venting Policy and Regulation, Washington D.C., March 2009.

[14] Process controllers, chemical pumps, and glycol pumps often vent pressurized natural gas used for pneumatic actuation.

In most cases these best practices improve safety and collect marketable gas for sale. For example, green completions provide an immediate revenue stream by routing gas that would otherwise be vented to a sale line. Industry has demonstrated that green completions are both best environmental practice and profitable. Green completion equipment has a short economic payout. A green completion requires the operator to bring in gas processing equipment to the well pad to clean up wet gas, improving it to gas pipeline quality. Typically, portable gas dehydration units, gas-liquid-sand separator traps, and additional tanks are required.[15] Most companies report a one-to-two-year payout for investment in their own green completion equipment, and substantial profit thereafter, depending on the gas flow rate.[16] It is also possible for smaller operators to rent green completion equipment. A recent New York State study for the Marcellus Shale found that equipment payouts may be as short as three months, and more than $65 million in profits was made on a national level in 2005 by companies conducting green completions.[17] Natural Gas STAR also provided technical advice to New York State recommending green completions as a technically feasible economic method. The best practice of green completions should be codified in DEP regulation.

Recommendation No. 20: DEP should develop regulations to restrict flaring, venting, and fugitive emissions to the lowest level technically feasible, and require the use of Reduced Emission Completions ("green completions") whenever technically feasible.

DEP proposes a new requirement at § 78.73(f) that reads:

> *"(f) Casing which is attached to a blow-out preventer with a pressure rating of greater than 3,000 psi shall be pressure tested. A passing pressure test shall be holding 120 percent of the highest expected working pressure of the casing string being tested for 30 minutes with not more than a 10 percent change. Certification of the pressure test shall be confirmed by entry and signature of the person performing the test on the driller's log."*

This regulation requires casing to be pressure tested only when it is attached to a BOP of a pressure rating greater than 3,000 psi. Industry standard practice is to pressure test casing whenever a BOP is installed on casing, not just on BOPs with more than a 3,000 psi rating.

Typically the casing must be able to hold a surface pressure at least equal to 50% of the required working pressure of the BOP. Specifying a surface pressure of at least 50% of the working pressure of the BOP is an easily quantifiable, verifiable value.

Pressure testing the casing is a very important step in groundwater protection. A failed pressure test indicates an integrity problem that could potentially provide a conduit from the well to adjacent aquifers.

Recommendation No. 21: DEP regulations at § 78.73(f) should be revised to require pressure testing of all casing at a surface pressure of 50% of the required working pressure of the BOP.

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[15] EPA, Green Completion, Partner Reported Opportunities (PROs) for Reducing Methane Emissions, Fact Sheet No. 703, 2004.
[16] Reduced Emissions Completions, Lessons Learned from Natural Gas STAR, Producers Technology Transfer Workshop, Casper Wyoming, August 30, 2005.
[17] DSGEIS, Appendix 25.

9. Subchapter D, Well Drilling, Operation and Plugging, Casing and Cementing, Use of Conductor Pipe, § 78.82

DEP proposes to revise § 78.82 to read:

> *"If the operator installs conductor pipe in the well, the following provisions shall apply:*
> *(i) The operator may not remove the pipe.*
> *(ii) Conductor pipe shall be installed in a manner that prevents infiltration of surface water or fluids from the operation into groundwater.*
> *(iii) Conductor pipe shall be made of steel."*

The proposed changes are useful and provide additional instruction on conductor pipe, but should be expanded further. Regulations should provide specific instructions on how an operator should install conductor pipe to prevent infiltration of surface water or fluids from the operation into groundwater.

Most commonly the conductor casing is installed with a cement seal at the surface to prevent groundwater contamination. Cement is placed in the annulus (the space between the outside of the pipe and inside of the hole), to secure the pipe in the hole and ensure there is a continuous barrier. DEP should specify that conductor pipe be cemented from top to bottom and firmly affixed in a central location in the wellbore with a continuous, equally thick layer of cement around the pipe.

Alternatively, if surface geology allows, conductor casing can be driven by mechanical percussion methods into unconsolidated strata. In this case, there is no annulus, and the casing is not cemented. And in this case, a mechanical or cement seal needs to be installed at the surface to prevent the downward migration of surface pollutants.

DEP should also provide instruction on what type of drilling fluids should be used when excavating the conductor casing hole, because this section of the well is being drilled through freshwater resources. Drilling fluids should be limited to air, fresh water, or water-based mud, and exclude oil based muds or use of other chemical lubricants.

Recommendation No. 22: DEP regulations at § 78.82 should include specific instructions on how an operator should install conductor pipe to prevent infiltration of surface water or fluids from the operation into groundwater. DEP should specify that conductor pipe be cemented from top to bottom and firmly affixed in a central location in the wellbore with a continuous, equally thick layer of cement around the pipe. A mechanical or cement seal should be installed at the surface to prevent the downward migration of surface pollutants. Drilling fluids should be limited to air, fresh water, or water-based mud, and exclude oil based muds or use of other chemical lubricants.

10. Subchapter D, Well Drilling, Operation and Plugging, Casing and Cementing, Surface and Coal Protective Casing and Cementing Procedures, § 78.83

DEP has proposed a number of important changes to the regulations at § 78.83. Revisions to this section of the regulations are most critical to DEP's stated goal of minimizing public concerns associated with gas migration into public drinking water supplies.

DEP proposes to revise § 78.83 to read:

“ (a) For wells drilled, altered, reconditioned or recompleted after [effective date], surface casing or any casing functioning as a water protection casing shall not be utilized as production casing except if one of the following applies:

(1) In oil wells where the operator does not produce any gas generated by the well and the annulus between the surface casing and the production pipe is left open.

(2) The operator demonstrates that the pressure in the wellbore at the casing seat is no greater than the pressure permitted by § 78.73(c) and demonstrates that all gas and fluids will be contained within the well.”

The proposed rule at § 78.83(a) starts off clear and robust. Clearly stated, casing functioning as a water protection casing shall not be utilized as production casing. This approach is logical, and important to groundwater resource protection. Water protection casing should be an ***additional*** string of piping, cemented from top to bottom and firmly affixed in a central location in the wellbore with a continuous, equally thick layer of cement around the pipe. By contrast with the clear initial prohibition, however, the two proposed exceptions to this rule at § 78.83(a)(1)-(2) do not make sense, and serve to compromise the protective barrier that surface casing is intended to create.

As drafted, § 78.83(a)(1) proposes to allow the surface casing to serve as production casing in an oil well where no gas is generated by the well and the annulus between the surface casing and the “production pipe” is left open. The term “production pipe” is not defined in DEP regulation at § 78.1, and it is not clear what piping string DEP is referencing. Is this DEP’s term for production tubing? This proposed exemption is not clear or technically supported.

As drafted, § 78.83(a)(2) proposes to allow the surface casing to serve as production casing in all wells if an operator demonstrates that the casing seat pressure does not exceed § 78.73(c) (which the operator is required to do anyway so this is not an incremental requirement) and if the operator demonstrates that all gas and fluids will be contained within the well. Yet DEP sets no criteria or approval process for making this showing. The proposed exemption at § 78.83(a)(2) defeats the purpose of requiring § 78.83(a).

Recommendation No. 23: DEP regulations at § 78.83(a) should be revised to read: Surface casing or any casing functioning as a water protection casing shall not be utilized as production casing.

Exemptions proposed at § 78.83(a)(1)-(2) should be deleted or further technical justification should be provided by DEP to explain why these proposed requirements are more protective of human health and the environment.

DEP’s proposed regulations at § 78.83(c) require an operator to set surface casing 50’ below the deepest fresh ground water or into consolidated rock, whichever is deeper. The technical basis for selecting a 50’ depth is not explained.

New York State has instituted more restrictive Fresh Water Aquifer Supplementary Permit Conditions on permits to drill for wells that pass through primary and principal aquifers, including setting surface casing at least 100' below the deepest fresh water zone and at least 100' into bedrock. Similar to DEP’s proposal later at § 78.83(f), NYS allows for this setting depth to be adjusted to ensure the casing seat is set above any hydrocarbon interval. DEP should provide a technical basis to show how the 50’ depth criteria is sufficient to protect water resources, or DEP should increase it to the more protective standard of 100’.

> **Recommendation No. 24**: DEP regulations at § 78.83(c) should be revised to increase the surface casing setting depth to 100’ below the deepest fresh water zone and at least 100' into bedrock. Correspondingly, DEP’s proposed regulation at § 78.83(f) needs to be adjusted to increase the 50’ criterion to 100’.

DEP’s proposed regulations at § 78.83(f) reads:

> *“The operator shall permanently cement the surface casing by placing the cement in the casing and displacing it into the annular space between the wall of the hole and the outside of the casing.”*

This language does not clearly require a continuous, equally thick layer of cement around the pipe. Nor does this language clarify that cement must be placed behind the casing from the bottom of the casing (casing seat) to the surface.

The most common methods of placing cement behind surface casing are the pump and plug or displacement methods that use sufficient cement to ensure a protective cement bond is achieved from the bottom of the casing to the top of the hole. To ensure that a continuous, equally thick layer of cement is achieved, with no void spaces, industry standard practice is to pump excess cement and verify its return at the surface. Pumping a minimum of 25% excess cement is common. If the excess cement does not return at the surface, a bond was not achieved behind the entire section of surface casing. In this case, steps must be taken to remedy the failed cement job. A common method is to install a cement basket and pump cement down the annulus from the surface. A cement bond log should be run to verify cement integrity prior to proceeding further in the wellbore.

> **Recommendation No. 25**: The following language should be added to DEP regulations at § 78.83(f): Surface casing must be cemented from top to bottom and firmly affixed in a central location in the wellbore with a continuous, equally thick layer of cement around the pipe. Cement must be placed behind surface casing by the pump and plug or displacement method and a sufficient amount of cement (at least 25% excess) must be used to ensure a protective cement bond is achieved from the bottom of the casing to the top of the hole. If the excess cement does not return at the surface, the operator must take steps to remedy the failed cement job, including pumping cement down the annulus from the surface to fill any void spaces. A cement bond log must be run to verify cement integrity prior to proceeding further in the wellbore. If the cement bond long does not verify placement of a continuous, solid layer of cement behind the surface casing from the bottom of the casing to the top of the hole, an additional string of casing must be set pursuant to § 78.83b(a)(1).

DEP’s regulations at § 78.83(g) reads:

> *“If additional fresh groundwater is encountered in drilling below the permanently cemented surface casing, the operator shall protect the additional fresh groundwater by installing and cementing a subsequent string of casing or other procedures approved by the Department to completely isolate and protect fresh groundwater. The string of casing may also penetrate zones bearing salty or brackish water with cement in the annular space being used to segregate the*

various zones. Sufficient cement shall be used to cement the casing at least 20 feet into the permanently cemented casing."

This regulation essentially says that if an operator sets surface casing too early,[18] and then continues to drill through freshwater, the operator must set another string of protective casing to "*completely isolate and protect the fresh groundwater*." The requirement to set a second set of casing is appropriate. This second set of casing is called "intermediate casing" and is a defined term in DEP regulations. The regulations should use this term for clarity.

The last line of this regulation requires the operator to place cement only 20' behind the intermediate casing, just above the casing shoe. This amount of cement is inadequate to "*completely isolate and protect the fresh groundwater*."

Depending on the intermediate casing seat depth, it may be possible to place cement behind the entire casing string. As explained above, industry trade groups operating in the Marcellus Shale in Pennsylvania[19] recommend 13-3/8" intermediate casing at depths up to 1,000' be cemented behind the entire section. Intermediate casing provides a second protective barrier across a freshwater aquifer. However, it is not usually possible to cement the entire intermediate casing string if it is more than a few thousand feet deep. In this case, intermediate casing strings are partially cemented in place to secure the lower section of the pipe. Most states specify a minimum number of feet of cement be placed behind intermediate casing (e.g. 500-600'). It is recommended that DEP apply similar standards.

Of note, § 78.83(g) conflicts with the new proposed regulation at § 78.83c for intermediate casing requiring cementing of at least 600' (which is more consistent with current regulatory practices in other states).

Recommendation No. 26: DEP regulation at § 78.83(g) should be revised to remove the last line and replace it with a requirement to install cement behind the entire section of the intermediate casing string, unless the operator can demonstrate it is not technically feasible to circulate cement all the way to the surface due to the depth of intermediate casing. In that case, a minimum of 600' of cement must be placed behind the casing, above the casing shoe. In all cases, the cement must be firmly affixed in the wellbore in a central location with a continuous, equally thick layer of cement around the pipe.

Inconsistencies between regulations at § 78.83(g) and § 78.83c should be remedied, because both seem to be addressing intermediate casing.

DEP's existing regulation at § 78.83(f) reads:

"Where potential oil or gas zones are anticipated to be found at depths within 50 feet below the deepest fresh groundwater, the operator shall set and permanently cement surface casing prior to drilling into a stratum known to contain, or likely containing, oil or gas."

As recommended above at § 78.83 (c) the 50' depth should be increased to 100', and the regulation should be clear that surface casing should stop above any significant pressure zone or hydrocarbon zone, to ensure the blowout preventer can be installed prior to drilling into a pressured zone or hydrocarbon

[18] Or in the in the case that freshwater intervals are separated by intervals of shallow gas requiring multiple casing strings to be set.

[19] *See* note 2, *supra.*

zone; and surface casing needs to be set to provide a protective barrier to prevent hydrocarbons from contaminating freshwater aquifers when the well is drilled deeper (below the surface casing).

Recommendation No. 27: Revise § 78.83(f) to read: Where potential oil or gas zones are anticipated at depths within 100 feet below the deepest fresh groundwater, the operator shall set and permanently cement surface casing prior to drilling into a stratum known to contain, or likely containing, oil or gas, to provide a protective barrier to prevent hydrocarbons from contaminating the fresh water aquifers when the well is drilled deeper. A blowout preventer must be installed prior to drilling into a pressured hydrocarbon zone.

DEP's existing regulation at § 78.83(c) and (h) require the use of centralizers. Centralizers are necessary to center the casing in the hole and ensure that a concentric cement ring is placed around the pipe, sealing the annular space between the wellbore and the casing. Once the casing is set, there is still drilling fluid inside the casing and in the annular space between the casing and the wellbore wall. Drilling mud is displaced out of the hole by pumping cement down the inside of the casing and up the back side of the annulus. Poorly centralized casing will allow the cement to bypass the drilling fluid, following the path of least resistance (usually down the wide side of the annulus), leaving drilling fluid behind the casing on the narrow side of the annulus; if this happens, a section of the annulus is not properly cemented/sealed. Centralizers serve many functions including: centering the casing; preventing drag while casing is run in the hole; minimizing differential sticking; aiding in mud displacement; and reducing mud channeling when cementing is underway. Centralizers need to be installed either on a casing collar or a mechanical stop collar. American Petroleum Institute Specification (API) 10D is the industry standard for proper selection, design, and placement of centralizers. It is recommended that this standard be referenced in the regulations, because the distance between centralizers is only one of the design criteria that should be considered when properly selecting, installing, and running casing centralizers.

Recommendation No. 28: Revise § 78.83(c) and (h) to include American Petroleum Institute Specification (API) 10D standard for centralizers.

DEP has proposed three new regulatory sections at § 78.83, and has labeled them § 78.83a, § 78.83b, and § 78.83c. Presumably these sections also apply to surface and coal protective casing and cementing procedures, although this is not clear and should be stated, or these requirements should just be added by expanding the existing standard at § 78.83 beginning at the letter (l) where the last regulation left off.

This numbering scheme has the potential to cause confusion with existing regulations at § 78.83(a), § 78.83(b) and § 78.83(c) and is not consistent with DEP's numbering scheme. As proposed, DEP's numbering scheme will include regulations labeled § 78.83(a) and § 78.83a(a).

Recommendation No. 29: Revise the § 78.83a, § 78.83b, and § 78.83c numbering scheme for consistency with existing DEP regulation format. DEP should clarify that these new standards apply to surface and coal protective casing and cementing procedures.

DEP has proposed a whole new regulatory section at § 78.83a that requires the operator to prepare and maintain a casing and cementing plan. DEP's proposed regulation at § 78.83a reads:

> *"§ 78.83a Casing and Cementing Plan*
> *(a) The operator shall prepare and maintain a casing and cementing plan showing how the well will be drilled and completed. The plan shall demonstrate compliance with this subchapter and include the following information:*

(1) The anticipated depth and thickness of any producing formation, expected pressures, and anticipated fresh groundwater zones.
(2) Diameter of the well bore,
(3) Casing type, depth, diameter, wall thickness and burst pressure rating.
(4) Cement type, additives and estimated amount.
(5) Estimated location of centralizers.
(6) Alternative methods or materials as required by the Department as a condition of the well permit.

(b) The plan shall be available at the well site for review by the Department.
(c) Upon request, the operator shall provide a copy of the well specific casing and cementing plan to the Department for review and approval.
(d) Any revisions to the plan made as a result of on-site modification must be documented by the operator and be available for review by the Department"

The proposed regulation is unclear. § 78.83a(a) requires the operator to prepare and maintain a casing and cementing plan, but does not require this plan to be submitted to DEP for review or approval.

Since the casing and cementing plan is not reviewed by DEP as part of the well permit (unless per § 78.83a(c) and DEP specifically requests it), how does DEP develop a list of "alternative methods or materials required" for the casing and cementing plan under § 78.83a(a)(6)? And how does DEP include that information in the well permit as described under § 78.83a(a)(6), if it doesn't normally review and approve casing and cementing plans?

Simply put, due to the importance of properly installing casing and cementing to protect groundwater, casing and cementing plans should be submitted to DEP as part of the well permit application, so that DEP can review, approve, and provide informed technical guidance to the operator in advance. Too often, regulators get involved in the tail end of the process, when the casing has been run, and the cement job has failed. Efficient and economic corrections are difficult to achieve at this stage. Advance review and approval is appropriate.

DEP proposes that the casing and cementing plan at § 78.83a(a)(1-6) include specific information. At § 78.83a(a)(3) DEP requests information on the casing burst pressure rating. Pipe strength information should be expanded beyond burst strength, to include collapse resistance and tensile strength, because to design a reliable casing string you must know the strength of the pipe under different load conditions.[20]

At § 78.83a(a)(3) DEP requests information on the casing type. This information should be expanded to include whether the casing is new or used casing, and if used, the date, condition, and location of prior use and prior service history should be recorded. As noted later in comments at §78.84, it is strongly recommended that no used casing be allowed for surface casing or intermediate casing, when its primary function is to protect groundwater. New casing should be used in these cases. However, in cases where used casing may be allowed by DEP (e.g. production casing), it is critical that DEP have a very thorough understanding of the service history and quality prior to allowing reuse.

The casing and cementing plan should include a quality control and quality assurance section that ensures the design specifications established by the engineering team, and approved by DEP, are followed in the field, and cement bond logs and pressure tests are run to verify integrity.

[20] Petroleum Engineering Handbook, Volume II, Drilling Engineering, Society of Petroleum Engineers, 2006.

Recommendation No. 30: Revise § 78.83a(a) to require the operator to prepare and submit a casing and cementing plan to DEP for review and approval as part of the well permit application.

DEP should review and approve a complete well drilling and completion plan application including a casing and cementing plan, as part of the well permitting process, so that appropriate permit stipulations may be placed in the permit.

Expand § 78.83a(a)(3) to include information on the casing's collapse resistance and tensile strength. Also require information on casing age, condition, location of prior use, and prior service history.

The casing and cementing plan should include a quality control and quality assurance section and should demonstrate conformance with the objectives of § 78.71, and procedures and standards of §§ 78.81-87.

The same recommendations regarding excess cement returns made at § 78.83(f) apply here at §78.83b(a).

Recommendation No. 31: Revise § 78.83b(a) to include the recommendations made at § 78.83(f) regarding a minimum 25% excess cement return.

The newly proposed regulations at § 78.83b(a)(1)-(2) and (b) are confusing, inconsistent with best practices for protecting groundwater, and conflict with the newly proposed intermediate casing regulations at § 78.83c(a)-(c).

The newly proposed regulations at § 78.83b(a)(1)-(2) read:

" (a) If cement used to permanently cement the surface or coal protective casing is not circulated to the surface, the operator shall do one of the following:

(1) Run an additional string of casing at least 50 feet deeper than the surface casing and cement the second string of casing back to the seat of the surface or coal protective casing and vent the annulus of the additional casing string to the atmosphere at all times unless closed for well testing or maintenance.

(2) if the additional string of casing is the production casing, the operator shall set the production casing on a packer and vent the annulus of the production casing to the atmosphere at all times unless closed for well testing or maintenance.

(a) If cement used to permanently cement the surface or coal protective casing is not circulated to the surface cement, the Department may require the operator to determine the amount of casing that was cemented by logging or other suitable method."

Under § 78.83b(a) when surface casing is set, if a cement job fails, and another set of casing (called intermediate casing) must be run, the operator would then go to the new section of the regulations at §78.83c(a)-(c) that provides instruction on how to install intermediate casing. This makes the new regulation at § 78.83b(a)(1) unnecessary. And as explained in the earlier recommendations at § 78.83, it may be possible to cement the entire section of intermediate casing, depending on depth. If possible, the entire length should be cemented in place.

§ 78.83b(a)(2), as proposed, does not make sense. It proposes to allow **production casing** to serve as a **groundwater protection** casing in the event surface casing is run, and the cement job fails. The reason this does not make sense is that an operator with a failed surface casing cement job would have to drill into a hydrocarbon bearing zone to set production casing, potentially exposing groundwater to hydrocarbon contamination.

Simply put, production casing cannot serve as groundwater protection casing. **Groundwater protection casing must be set below the groundwater, but above the hydrocarbon zone**, firmly anchored. If the first set of surface casing was not cemented in place properly, a second set (intermediate casing) must be run and cemented in place to ensure groundwater protection, prior to entering the hydrocarbon zone.

The production casing, by DEP's own definition at § 78.1, is: *"A string of pipe other than surface casing and coal protective casing which is run for the purpose of confining or conducting hydrocarbons and associated fluids from one or more producing horizons to the surface."* To set production casing, the operator would have to drill into the hydrocarbon-bearing zone; meanwhile, keep in mind that if the surface casing was not properly cemented, drilling into the production zone creates a potential pathway for hydrocarbons to reach groundwater behind improperly cemented casing.

§ 78.83b(b) is even more perplexing, because after reading § 78.83b(a), where the operator is clearly instructed to run another string of casing after a failed surface casing and cement job, § 78.83b(b) requests the operator to further examine the cement condition by logging or other methods. A more logical progression, and a more common progression, is the one explained above in the surface casing regulations. The surface casing cementing program should be designed with at least 25% excess cement. Excess cement should be observed at the surface. Cement bond logs should be run as a normal suite of quality control and assurance, to verify cement quality prior to proceeding. If necessary, additional cementing may be needed to fill voids (if any). If the cement job cannot be remedied, with routine cementing procedures, it may be necessary to run a string of intermediate casing and cement it in place.

Recommendation No. 32: Revise § 78.83b to clearly state that if surface casing is not properly cemented in place with at least 25% excess cement returns at the surface, intermediate casing must be run and cemented in place following the recommendations made above at § 78.83. Cement bond logs should be run to verify cement quality. The proposal to allow an operator to continue drilling into a hydrocarbon bearing zone to set production casing, in the presence of a known failed surface casing cement job, is technically unsound and environmentally hazardous, and should be deleted.

11. Subchapter D, Well Drilling, Operation and Plugging, Casing and Cementing, Casing Standards, § 78.84

DEP's casing standard requirement at § 78.84(a) should include a requirement to design and install casing to withstand the effects of corrosion and erosion, in addition to the other factors listed. This can included using coated piping, higher grade pipe, or thicker walled pipe with a higher corrosion allowance.

Recommendation No. 33: Revise § 78.84(a) to include a requirement to design and install casing to withstand the effects of corrosion and erosion.

DEP has added a new regulation at § 78.84(b) that reads:

> *"(b) Surface casing shall be a string of new pipe with a pressure rating that is at least 20 percent greater than the anticipated maximum pressure. Used casing may be approved for use but must be pressure tested after cementing and before continuation of drilling. A passing pressure test is holding the anticipated maximum pressure for 30 minutes with not more than a 10 percent change in pressure."*

This standard allows the use of new or used surface casing. The quality of intermediate casing is not addressed.

Surface casing should not be constructed of used casing. Surface casing and intermediate casing should be made of new, high-quality piping. Keep in mind that surface casing and intermediate casing both play an important role in: preventing the contamination of freshwater; confining fluids to the wellbore; preventing migration of fluids and hydrocarbons from one stratum to another; ensuring control of well pressures encountered; and providing well control until the next casing is set. Oil and gas wells may be subject to elevated temperatures, pressures, erosion, corrosion, and other factors that reduce the operating life of the casing string, and its ability to protect groundwater supplies. Installation of new piping maximizes public and environmental protection, by extending the life cycle of the well.

> **Recommendation No. 34**: DEP regulation at § 78.84(b) should be revised to read: (b) Surface and intermediate casing shall be a string of new casing with a pressure rating that is at least 20 percent greater than the anticipated maximum pressure.

Similarly, DEP should revise § 78.84(c) to require new welded piping for surface and intermediate casing strings.

The exemption for not obtaining API welder's certification at § 78.84(c)(3) appears to have a typo. Should it be "within **90 days** of the effective date," instead of "within **9** of the effective date"? The justification for the welding certification exemption is not clear. API welder's certifications were developed to improve the quality and consistency of casing and other types of piping welds. There are rigorous training and qualification requirements, and quality control and assurance procedures that must be followed. If a welder is not API certified, DEP should evaluate if there is an equivalent state welding certification training program in Pennsylvania that could be substituted. Alternatively, DEP should consider if a Pennsylvania certification program could be developed to test and certify those with existing experience, to validate their training, experience, and quality control and quality assurance procedures.

The technical basis for grandfathering in welders with 10 years or more experience is not clear. While these welders may have many years of welding experience, the concern is that they may not be familiar with the new quality control and quality assurance procedures that have been developed. Certification programs provide continuing education opportunities and information on new techniques as they are developed.

> **Recommendation No. 35**: Revise § 78.84(c) to require new welded piping for surface and intermediate casing strings and API welder's certification. Alternatively, consider substitution of the API certification with an equivalent state welding certification training program. Allow a reasonable transition period to allow welders time to obtain this new certification.

12. Subchapter D, Well Drilling, Operation and Plugging, Casing and Cementing, Cement Standards, § 78.85

DEP's revised cement standard at § 78.85 (a) reads:

> *"(a) The operator shall use cement that meets or exceeds the ASTM International C 150, type I, II or II standard. The cement shall also:*
> *(1) Secure the casing in the well bore,*
> *(2) Isolate the wellbore from fresh groundwater,*
> *(3) Contain any pressure from drilling, completion and production,*
> *(4) Protect the casing from corrosion, and*
> *(5) Resist degradation by the chemical and physical conditions in the well.*
> *(6) Prevent gas migration"*

The proposed language at § 78.85 (a) appears to have a few typos: type II is listed twice; in subsection (4), the word "and" should be deleted; in subsection (5), the period should be replaced with a comma, followed by the word "and"; and subsection (6) should close with a period.

In addition to preventing gas migration, as noted at § 78.85 (a)(6), cement should also prevent migration of fluids and hydrocarbons from one stratum to another.

Recommendation No. 36: Revise § 78.85(a) to correctly reference the ASTM International Standard for Portland Cement. Correct the typographical errors in Revise § 78.85 (a)(4)-(6). Revise § 78.85(a)(6) to read: Prevent migration of fluids and hydrocarbons, including gas, from one stratum to another.

DEP's existing regulation at § 78.85(b) includes a 350 psi compressive strength standard. As recommended, and described in detail in the comment on the definition of "cement" at § 78.81, DEP should consider a higher compressive strength standard to protect groundwater, especially in the critical zone of cement.

Recommendation No. 37: Revise § 78.85(b) to increase the compressive strength standard, consistent with the recommendations made at § 78.81.

13. Subchapter D, Well Drilling, Operation and Plugging, Casing and Cementing, Mechanical Integrity of Operating Wells, § 78.88

DEP has proposed a new section of regulations for operating wells at § 78.88. The proposed regulations at § 78.88(a) require quarterly well inspections to verify the operating condition of the well, identify maintenance and repair needs, and take corrective action. Routine well integrity monitoring is best practice. Quarterly inspections, however, are too infrequent. Daily, or at least weekly, inspections are recommended.

Recommendation No. 38: Revise § 78.88(a) to increase the operating well inspection frequency to daily, or at least weekly.

DEP's proposed regulation at § 78.88(b)(3) requires the operator to determine if gas is escaping from the well, and the amount. DEP's proposed regulation at § 78.88(b)(4) requires the operator to determine if there is evidence of progressive corrosion, rusting, or other signs of equipment deterioration. Yet, DEP does not require the operator to take any action to stop the gas leak or remedy the corrosion, or equipment deterioration, except to take action to meet § 78.73(c) (to minimize pressure at the casing seat) or report the mechanical integrity problem at § 78.88(e).

Recommendation No. 39: Revise §7 8.88 to require wells with mechanical integrity problems to be repaired, shut in, or plugged and abandoned, as appropriate and safe to protect human health and the environment. The annual mechanical integrity report required at § 78.88(e) should summarize both the compliance status of each well and what action was taken to remedy non-compliant wells.

14. Subchapter D, Well Drilling, Operation and Plugging, Casing and Cementing, Stray Gas Mitigation Response, § 78.89

DEP has proposed a new section of regulations for stray gas mitigation response at § 78.89. A stray gas mitigation response regulation is an excellent addition; however, the title should be expanded beyond "stray gas" to address the broad range of responses described and anticipated in § 78.89 (a), including "oil" and "other fluids" (presumably chemicals and well stimulation fluids).

Recommendation No. 40: Revise § 78.89 throughout, to address potential leaks and/or contamination from "stray gas," "oil," and/or "other fluids," including but not limited to chemicals and well stimulation fluids.

DEP's proposed regulation at §78.89(b) requires the operator to "immediately" notify DEP and conduct an investigation when the operator becomes aware of a "stray gas incident". Yet there is no timeframe designated for when the operator and DEP need to respond to the situation. The notification requirement and response action obligation should be extended to incidents including "oil" and "other fluids".

Recommendation No. 41: Revise the last sentence of § 78.89(b) to read: The operator, in conjunction with the Department and local emergency response agencies, shall **immediately** take measures to ensure public health, safety, and welfare. The requirements proposed at § 78.89(b) should be extended to oil and other chemicals.

15. Subchapter D, Well Drilling, Operation and Plugging, Casing and Cementing, Plugging, § 78.91-98

Properly plugging and abandoning a well is critical to the protection of groundwater resources. In addition to DEP regulations at §§ 78.91-78.98, DEP should consider enhancing the regulations to require longer and additional cement barriers to ensure that hydrocarbons and freshwater are confined to their respective indigenous strata, and are prevented from migrating into other strata or to the surface. For example, while

DEP uses a 50' cement barrier, other states like Alaska require double the protection at 100'.[21] Texas requires an operator to submit a plugging procedure for agency review and approval.[22]

Recommendation No. 42: Revise the regulations at §§ 78.91-78.98 to include the following:

Plugging a wellbore must be performed in a manner that ensures that all hydrocarbons and freshwater are confined to their respective indigenous strata and are prevented from migrating into other strata or to the surface.

All hydrocarbon-bearing strata should be permanently sealed off by installing a cement barrier at least 100 feet below the base to 100 feet above the top of all hydrocarbon-bearing strata.

Plugging of a well must include effective segregation of uncased and cased portions of the wellbore to prevent vertical movement of fluid within the wellbore. A continuous cement plug must be placed from at least 100 feet below to 100 feet above the casing shoe.

The operator is required to submit records to DEP to demonstrate that the well was plugged in compliance with DEP regulations.

16. Subchapter D, Well Drilling, Operation and Plugging, Casing and Cementing, Well Record and Completion Report, § 78.122

DEP regulations at § 78.122(a)(6) should be expanded to include intermediate casing.

Recommendation No. 43: Revise the regulations at § 78.122(a)(6) to include intermediate casing.

DEP regulations at § 78.122(a)(7) should be expanded to include the requirement to submit an electronic copy of the cement bond log to verify cement integrity behind any casing used to protect groundwater resources, including surface and intermediate casing.

Recommendation No. 44: Revise the regulations at § 78.122(a)(7) to require submission of an electronic copy of the cement bond log.

DEP regulations at § 78.122(a) should be expanded to address waste.

Recommendation No. 45: Revise the regulations at § 78.122(a) to require a list of waste generated during drilling and workover operations, and a description of the waste handling and disposal methods and locations.

DEP revised the regulations at § 78.122(b)(6) to require additional information on stimulation procedures. It is recommended that the "composition" of stimulation fluids, including a list of all additives, identifying all chemical components, be reported.

[21] 20 AAC 25.
[22] 16 TAC Part 1§3.14

The lowest environmental impact methods should be considered. Possible methods for further DEP examination include:

1. Waste minimization (drilling mud recycle and reuse when possible);
2. Use of drilling mud additives with lower environmental impact;
3. Beneficial reuse of uncontaminated drilling wastes;
4. Use of closed loop tank systems to transport waste, versus use of reserve pits;
5. Burial (e.g. landfills, or reserve pits);
6. Commercial treatment and disposal facilities; and/or
7. Underground injection.

Recommendation No. 46: Revise the regulations at § 78.122(b)(6) to include information on the chemical additives, including all chemical components. Reported information should include biodegradability, bioaccumulation potential, toxicity, and any detrimental mutagenic or reproductive affects. Best practices would include a requirement to forbid chemicals that have low biodegradability, high bioaccumulation potential, high acute toxicity, or detrimental mutagenic or reproductive affects.

DEP regulations at § 78.122(b) should be expanded to provide a list of all waste generated during well completion operations, and a description of waste handling and disposal methods and locations. See waste management methods for consideration in Recommendation 45 above.

Recommendation No. 47: Revise the regulations at § 78.122(b) to require a list of waste generated during well completion operations, and a description of the waste handling and disposal methods and locations.

17. Copyrighted Standards

DEP should obtain a public access license to all copyrighted standards (e.g. API, ASTM) that are not available in the public domain. Regulations should be available for public review and comment, without having to purchase very expensive copies of copyrighted standards to understand the criteria and requirements that DEP is proposing. It is useful to reference technical standards and best practices when they serve to provide clear instruction; however, the public must be able to read and understand the regulations without an unreasonable financial burden. The cost to obtain a copy of these copyrighted standards can range up to several hundred dollars per standard.

Recommendation No. 48: Ensure that the public has access to all technical standards and criteria referenced in DEP's regulations. A public access version should be made available on the DEP website.

18. Inspection and Enforcement Program

Drafting new regulations to minimize contamination from oil and gas development in Pennsylvania is an important first step. New regulations must be accompanied by a rigorous inspection and enforcement program. It would be very useful for DEP to provide information on how it plans to expand and enhance its current inspection and enforcement program. DEP should provide more information on the following topics: budget, number of inspectors, inspector qualifications and expertise, frequency of inspections, type of inspections, and enforcement procedures and guidelines.

DEP should demonstrate that it has sufficient resources to oversee, inspect, and enforce the proposed enhanced regulations. This increases public confidence that a plan is not only required, but that DEP will ensure that it is followed.

Recommendation No. 49: DEP should provide information on how it plans to expand and enhance its current inspection and enforcement program to ensure regulatory compliance.

Federal Register

Wednesday,

January 14, 2009

Part II

Securities and Exchange Commission

17 CFR Parts 210, 211 et al.

Modernization of Oil and Gas Reporting; Final Rule

SECURITIES AND EXCHANGE COMMISSION

17 CFR Parts 210, 211, 229, and 249

[Release Nos. 33–8995; 34–59192; FR–78; File No. S7–15–08]

RIN 3235–AK00

Modernization of Oil and Gas Reporting

AGENCY: Securities and Exchange Commission.

ACTION: Final rule; interpretation; request for comment on Paperwork Reduction Act burden estimates.

SUMMARY: The Commission is adopting revisions to its oil and gas reporting disclosures which exist in their current form in Regulation S–K and Regulation S–X under the Securities Act of 1933 and the Securities Exchange Act of 1934, as well as Industry Guide 2. The revisions are intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves, which should help investors evaluate the relative value of oil and gas companies. In the three decades that have passed since adoption of these disclosure items, there have been significant changes in the oil and gas industry. The amendments are designed to modernize and update the oil and gas disclosure requirements to align them with current practices and changes in technology. The amendments concurrently align the full cost accounting rules with the revised disclosures. The amendments also codify and revise Industry Guide 2 in Regulation S–K. In addition, they harmonize oil and gas disclosures by foreign private issuers with the disclosures for domestic issuers.

DATES: *Effective Date:* January 1, 2010.

Comment Date: Comments on the Paperwork Reduction Act Analysis should be received on or before February 13, 2009.

ADDRESSES: Comments may be submitted by any of the following methods:

Electronic Comments

- Use the Commission's Internet comment form (*http://www.sec.gov/rules/proposed.shtml*); or
- Send an e-mail to *rule-comments@sec.gov*. Please include File Number S7–15–08 on the subject line; or
- Use the Federal e-Rulemaking Portal *http://www.regulations.gov*. Follow the instructions for submitting comments.

Paper Comments

- Send paper submissions in triplicate to Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090.

All submissions should refer to File Number S7–15–08. This file number should be included on the subject line if e-mail is used. To help us process and review your comments more efficiently, please use only one method. The Commission will post all comments on the Commission's Internet Web site (*http://www.sec.gov/rules/concept.shtml*). Comments also are available for public inspection and copying in the Commission's Public Reference Room, 100 F Street, NE., Washington, DC 20549, on official business days between the hours of 10 a.m. and 3 p.m. All comments received will be posted without change; we do not edit personal identifying information from submissions. You should submit only information that you wish to make available publicly.

FOR FURTHER INFORMATION CONTACT: Ray Be, Special Counsel, Office of Chief Counsel at (202) 551–3500; Dr. W. John Lee, Academic Petroleum Engineering Fellow, or Brad Skinner, Senior Assistant Chief Accountant, Office of Natural Resources and Food at (202) 551–3740; Leslie Overton, Associate Chief Accountant, Office of Chief Accountant for the Division of Corporation Finance at (202) 551–3400, Division of Corporation Finance; or Mark Mahar, Associate Chief Accountant, Jonathan Duersch, Assistant Chief Accountant, or Doug Parker, Professional Accounting Fellow, Office of the Chief Accountant at (202) 551–5300; U.S. Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–3628.

SUPPLEMENTARY INFORMATION: We are adopting amendments to Rule 4–10 [1] of Regulation S–X [2] and Items 102, 801 and 802 [3] of Regulation S–K.[4] We also are adding new Subpart 1200, including Items 1201 through 1208, to Regulation S–K.

Table of Contents

[1] 17 CFR 210.4–10.

[2] 17 CFR 210.

[3] 17 CFR 229.102, 17 CFR 229.801, and 17 CFR 229.802.

[4] 17 CFR 229.

I. Introduction

A. Background

On June 26, 2008, the Commission issued a proposing release (Proposing Release) seeking public comment on proposed amendments to the disclosure requirements regarding oil and gas companies.[5] These proposals encompassed issues that were previously addressed more generally in a concept release that the Commission issued on December 12, 2007 (Concept Release),[6] which solicited comment on possible revisions to the oil and gas reserves disclosure requirements specified in Rule 4–10 of Regulation S–X[7] and Item 102 of Regulation S–K.[8] The Proposing Release also contained proposals not addressed by the Concept Release related to the updating and codification of Industry Guide 2.

We initially adopted our oil and gas disclosure requirements in 1978 and 1982.[9] Since that time, there have been significant changes in the oil and gas industry and markets, including technological advances, and changes in the types of projects in which oil and gas companies invest their capital.[10] Prior to our issuance of the Concept Release and the Proposing Release, many industry participants had expressed concern that our disclosure rules are no longer in alignment with current industry practices and therefore limit their usefulness to the market and investors.[11]

B. Issuance of the Concept Release

The Concept Release addressed the potential implications for the quality, accuracy and reliability of oil and gas disclosure if the Commission were to:

- Revise the definition of ''proved reserves'' in our rules, in particular, the criteria used to assess and quantify resources that can be classified as proved reserves; and
- Expand the categories of resources that may be disclosed in Commission filings to include resources other than proved reserves.

In addition, the Concept Release questioned whether our revised disclosure rules should be modeled on any particular resource classification framework currently being used within the oil and gas industry. We also asked how any revised disclosure rules could be made flexible enough to address future technological innovation and changes within the oil and gas industry. The Concept Release sought further comment on whether the Commission should require independent third-party assessments of reserves estimates that a company includes in its filings.

In response to the Concept Release, commenters submitted 80 comment letters.[12] We received comment letters from a variety of industry participants such as accounting firms, engineering consulting firms, domestic and foreign oil and gas companies, federal government agencies, individuals, law firms, professional associations, public interest groups, and rating agencies. We considered these comments and addressed many of them in issuing the Proposing Release.

C. Overview of the Comment Letters Received on the Proposing Release

The Proposing Release sought significantly more detailed comment on issues raised in the Concept Release, as well as proposed amendments to the disclosure items in our rules and Industry Guide 2. In response to the Proposing Release, we received 65 comment letters, again from a variety of constituents with interests in oil and gas industry disclosure.

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[5] Release No. 33–8935 (June 27, 2008) [73 FR 39181].

[6] Release No. 33–8870 (Dec. 12, 2007) [72 FR 71610].

[7] 17 CFR 210.4–10. See Release No. 33–6233 (Sept. 25, 1980) [45 FR 63660] (adopting amendments to Regulation S–X, including Rule 4–10). The precursor to Rule 4–10 was Rule 3–18 of Regulation S–X, which was adopted in 1978. See Accounting Series Release No. 253 (Aug. 31, 1978) [43 FR 40688]. See also Accounting Series Release No. 257 (Dec. 19, 1978) [43 FR 60404] (further amending Rule 3–18 of Regulation S–X and revising the definition of proved reserves).

[8] Item 102 of Regulation S–K [17 CFR 229.102]. In 1982, the Commission adopted Item 102 of Regulation S–K. Item 102 contains the disclosure requirements previously located in Item 2 of Regulation S–K. See Release No. 33–6383 (March 16, 1982) [47 FR 11380]. The Commission also ''recast * * * the disclosure requirements for oil and gas operations, formerly contained in Item 2(b) of Regulation S–K, as an industry guide.'' See Release No. 33–6384 (Mar. 16, 1982) [47 FR 11476].

[9] The disclosure requirements were introduced pursuant to a directive in the Energy Policy and Conservation Act of 1975 (the ''EPCA''). The EPCA directed the Commission to ''take such steps as may be necessary to assure the development and observance of accounting practices to be followed in the preparation of accounts by persons engaged, in whole or in part, in the production of crude oil or natural gas in the United States.'' See 42 U.S.C. 6201–6422.

[10] See, for example, Daniel Yergin and David Hobbs: ''The Search for Reasonable Certainty in Reserves Disclosure,'' Oil and Gas Journal (July 18, 2005).

[11] See, for example, Greg Courturier, ''Standard & Poor's Urges SEC to Change Disclosure Rules,'' International Oil Daily (Dec. 3, 2007); Steve Levine, ''Tracking the Numbers: Oil Firms Want SEC to Loosen Reserves Rules,'' Wall Street Journal Online (Feb. 7, 2006); Christopher Hope, ''Oil Majors Back Attack on SEC Rules,'' The Daily Telegraph (London) (Feb. 24, 2005); Barrie McKenna, ''Rules undervalue reserves report says: Volumes buried in Canada's oil sands not counted by SEC's measure,'' The Globe & Mail (Canada) (Feb. 24, 2005); and ''Deloitte Calls on Regulators to Update Rules for Oil and Gas Reserves Reporting,'' Business Wire Inc. (Feb. 9, 2005).

[12] The public comments we received are available for inspection in the Commission's Public Reference Room at 100 F St., NE., Washington, DC 20549 in File No. S7–29–07. They are also available on-line at *http://www.sec.gov/comments/s7-29-07/s72907.shtml*.

Almost all commenters supported some form of revision to the current oil and gas disclosure requirements, particularly given the length of time that has elapsed since the requirements were initially adopted.[13] Commenters provided significantly more detailed comments on the Proposing Release than on the Concept Release, which did not include specific proposed regulatory text. We discuss those comments in detail in the relevant sections of this release. However, in general, commenters focused on several key issues raised by the Proposing Release. These issues included the following:

• The proposal to permit disclosure of probable and possible reserves;

• The proposed use of average historical prices to represent existing economic conditions to determine the economic producibility of oil and gas reserves for disclosure purposes while continuing to use a single day year-end price to determine the economic producibility of reserves for accounting purposes;

• The proposed inclusion of bitumen, oil shales, and other resources in the definition of ''oil and gas producing activities'';

• The proposed provision to broaden the types of technology that a company may use to establish reserves estimates and categories;

• The proposed change in the definition of proved undeveloped reserves to eliminate the ''certainty'' requirement; and

• The increased detail of disclosure that would be required as a result of our proposed definition of ''geographic location.''

II. Revisions and Additions to the Definition Section in Rule 4–10 of Regulation S–X

A. Introduction

The revisions and additions to the definition section in Rule 4–10(a) of Regulation S–X [14] update our reserves definitions to reflect changes in the oil and gas industry and markets and new technologies that have occurred in the decades since the current rules were adopted. Many of the definitions are designed to be consistent with the Petroleum Resource Management System (PRMS).[15] Among other things, the revisions to these definitions address four issues that have been of particular interest to companies, investors, and securities analysts:

• The use of single-day year-end pricing to determine the economic producibility of reserves;

• The exclusion of activities related to the extraction of bitumen and other ''non-traditional'' resources from the definition of oil and gas producing activities;

• The limitations regarding the types of technologies that an oil and gas company may rely upon to establish the levels of certainty required to classify reserves; and

• The limitation in the current rules that permits oil and gas companies to disclose only their proved reserves.

The revisions of, and additions to, the Rule 4–10 definitions attempt to address these issues without sacrificing clarity and comparability, which provide protection and transparency to investors. In addition, to the extent appropriate, we have revised our proposals so that the final definitions are more consistent with terms and definitions in the PRMS to improve compliance and understanding of our new rules.

B. Pricing Mechanism for Oil and Gas Reserves Estimation

1. 12-Month Average Price

The final rules define the term ''proved oil and gas reserves'' in part as ''those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.'' The definition states that the economic producibility of a reservoir must be based on existing economic conditions. It specifies that, in calculating economic producibility, a company must use a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.[16]

Most commenters supported the use of a 12-month average price to serve as a proxy for existing economic conditions to determine the economic producibility of reserves.[17] Some noted that a 12-month average price is considered to reflect ''current economic conditions'' by PRMS.[18] They noted that the use of an average price would reduce the effects of short term volatility [19] and seasonality,[20] while

[13] See letters from American Association of Petroleum Geologists (''AAPG''), American Clean Skies Foundation (''American Clean Skies''), American Petroleum Institute (''API''), AngloGold Ashanti Ltd. (''AngloGold''), Apache Corporation (''Apache''), BHP Billiton Petroleum (''BHP''), BP Plc. (''BP''), Brookwood Petroleum Advisors, Ltd. (''Brookwood''), Canadian Association of Petroleum Producers (''CAPP''), Canadian Natural Resources Ltd. (''Canadian Natural''), Center for Audit Quality (''CAQ''), Center for Corporate Policy (''CCP''), CFA Institute Centre for Financial Market Integrity (''CFA''), Chesapeake Energy Corporation (''Chesapeake''), Chevron Corporation (''Chevron''), Coeur d'Alene Mines Corporation (''Coeur''), Cunningham, Peter (''Cunningham''), Davis, Polk & Wardwell (''Davis Polk''), Deloitte & Touche (''Deloitte''), Devon Energy Corporation (''Devon''), EnCana Corporation (''EnCana''), Energen Corporation (''Energen''), Energy Information Administration (of DOE) (''EIA''), Eni S.p.A. (''Eni''), Equitable Resources, Inc. (''Equitable''), Ernst & Young (''E&Y''), Evolution Petroleum Corporation (''Evolution''), ExxonMobil Corporation (''ExxonMobil''), Federal Energy Regulatory Commission (''FERC''), Graff Consulting Group LLC (''Graff Consulting''), Grant Thornton (''Grant Thornton''), Imperial Oil Ltd. (''Imperial''), Independent Petroleum Association of America (''IPAA''), KPMG (''KPMG''), Luscher, Brian (''Luscher''), Magoto, Joseph (''Magoto''), McMoRan Exploration Co. (''McMoRan''), Newfield Exploration Company (''Newfield''), Nexen, Inc. (''Nexen''), Peabody Energy Corporation (''Peabody''), Petro-Canada (''Petro-Canada''), Petroleo Brasileiro S.A. (''Petrobras''), Petroleos Mexicanos (''PEMEX''), PRA International Ltd. (''PRA''), PriceWaterhouseCoopers (''PWC''), Questar Market Resources (''Questar''), RepsolYPF, S.A. (''Repsol''), Ross Petroleum Ltd. (''Ross''), Ryder Scott Company, L.P. (''Ryder Scott''), Sasol Ltd. (''Sasol''), Senator Robert Menendez, Senator Russell D. Feingold, and Senator Bernard Sanders, U.S. Senate (''Three Senators''), Shearman & Sterling (''Shearman & Sterling''), Shell International B.V. (''Shell''), Society of Exploration Geophysicists (''SEG''), Society of Petroleum Engineers (''SPE''), Society of Petroleum Evaluation Engineers (''SPEE''), Southwestern Energy Production Company (''Southwestern''), Standard Advantage (''Standard Advantage''), StatoilHydro (''StatoilHydro''), Swift Energy Company (''Swift''), Talisman Energy Inc. (''Talisman''), Total, S.A. (''Total''), van Wyk, Mike (''van Wyk''), Wagner, Robert (''Wagner''), Zakaib, Geoff (''Zakaib'').

[14] 17 CFR 210.4–10(a).

[15] The Petroleum Resources Management System is a widely accepted standard for the management of petroleum resources developed by several industry organizations. See Society of Petroleum Engineers, the World Petroleum Council, American Association of Petroleum Geologists, and the Society of Petroleum Evaluation Engineers, *Petroleum Resources Management System,* SPE/WPC/AAPG/SPEE (2007).

[16] See Rule 4–10(a)(22)(v) [17 CFR 210.4–10(a)(22)(v)].

[17] See letters from AngloGold, Apache, API, BHP, BP, Canadian Natural, CAPP, Chesapeake, Chevron, Devon, EIA, EnCana, Equitable, Evolution, ExxonMobil, Newfield, Nexen, Petrobras, Petro-Canada, PWC, Questar, Repsol, Ryder Scott, Sasol, Shell, Southwestern, SPE, Total, and Wagner.

[18] See letters from AngloGold, BHP, Equitable, Ryder Scott, and SPE.

[19] See letters from Apache, API, BHP, BP, Canadian Natural, CAPP, Chesapeake, EIA, EnCana, Equitable, Evolution, ExxonMobil, Imperial, IPAA, Newfield, Petrobras, Petro-Canada, Repsol, Ryder Scott, SPE, Total, and Wagner.

[20] See letters from Apache, Canadian Natural, Devon, EnCana, Evolution, IPAA, Petro-Canada, Repsol, and Ryder Scott.

maintaining comparability of disclosures among companies.[21]

Seven commenters recommended the use of first-of-the-month prices [22] instead of the proposed use of end-of-the-month prices because the use of first-of-the-month prices would provide companies with more time to estimate their reserves [23] and they thought that these prices better reflect the actual price received under typical natural gas contracts.[24] Conversely, six commenters recommended the use of a 12-month daily average price [25] because they thought that a daily average price would be more appropriate than a monthly average price. These commenters noted that oil sales contracts often are based on daily averages.[26] Two commenters expressed concern that end-of-the-month prices are not representative of actual prices because commodity traders often ''clear their books'' at the end of the month.[27]

One commenter opposed the use of average prices stating that, conceptually, the use of average prices is poor regulatory policy and may encourage the market to pressure standard setters to use historical average prices for financial instruments and other assets and liabilities associated with volatile markets.[28] It noted that volatility reflects the underlying economics of the oil and gas industry.[29]

The objective of reserves estimation is to provide the public with comparable information about volumes, not fair value, of a company's reserves available to enable investors to compare the business prospects of different companies. The use of a 12-month average historical price to determine the economic producibility of reserves quantities increases comparability between companies' oil and gas reserve disclosures, while mitigating any additional variability that a single-day price may have on reserve estimates. Although oil and gas prices themselves are subject to market-based volatility, the estimation of reserves quantities based on any historical price assumption determines those reserves quantities as if the oil or gas already has been produced, even though they have not, and these measures do not attempt to portray a reflection of their fair value. If the objective of reserve disclosures were to provide fair value information, we believe a pricing system that incorporates assumptions about estimated future market prices and costs related to extraction could be a more appropriate basis for estimation.

In order to provide disclosures which are more consistent with the objective of comparability, the amendments state that the existing economic conditions for determining the economic producibility of oil and gas reserves include the 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period.[30] For example, a company with a reporting year end of December 31 would determine its reserves estimates for its annual report based on the average of the prices for oil or gas on the first day of every month from January through December. Therefore, the use of a 12-month average price provides companies with the ability to efficiently prepare useful reserve information without sacrificing the objective of comparability. We believe that the revised definition of the term ''proved oil and gas reserves'' will provide investors with improved reserves information thereby enhancing their ability to analyze the disclosures.

2. Prices Used for Disclosure and Accounting Purposes

A proposal that resulted in significant comment was the use of a 12-month average price to estimate reserves for disclosure purposes, but a single-day, year-end price for accounting purposes.[31] All commenters addressing the issue of using different prices to determine reserves for disclosure and accounting opposed the proposal.[32] We are not adopting this aspect of the proposal. Instead, we are revising both our disclosure rules and our full-cost accounting rules related to oil and gas reserves to use a single price based on a 12-month average.[33] We also will continue to communicate with the FASB staff to align their accounting standards with these rules.

Commenters pointed out that the use of two different prices for disclosure and accounting purposes could:

- Confuse investors and other users of financial statements.[34]
- Create misleading information; [35]
- Harm comparability; [36]
- Decrease transparency; [37]
- Increase costs and burden significantly; [38]
- Increase the complexity of disclosures; [39]
- Double recordkeeping burden; [40]
- Require more disclosure to explain the differences in reserves estimates; and [41]
- Break the connection between disclosures and accounting.[42]

Some commenters noted that the disclosure and accounting rules and guidance do not use a different pricing method in other situations.[43] In addition, several commenters believed that changing to the use of an average price to estimate proved reserves would have a minimal impact on depreciation and net income.[44] We believe that changing the rules to use a 12-month average price in reserves estimations is

[21] See letters from BHP, Canadian Natural, CAPP, Deloitte, Devon, IPAA, Newfield, Petro-Canada, Total, and Wagner.

[22] See letters from Apache, BP, Chesapeake, Chevron, Devon, Repsol, and Shell.

[23] See letters from Chesapeake, Devon, and Shell.

[24] See letters from Apache, Newfield, and Repsol.

[25] See letters from Canadian Natural, CAPP, EnCana, Nexen, Petro-Canada, and Repsol.

[26] See letter from Newfield.

[27] See letters from Apache and Shell.

[28] See letter from CFA.

[29] See letter from CFA.

[30] See new Rule 4–10(a)(22)(v) of Regulation S–X [17 CFR 210.4–10(a)(22)(v)].

[31] Currently, companies use a single-day, year-end price to determine the quantity of its proved reserves. From an accounting perspective, the quantity of those reserves, while not included on the balance sheet, is used to determine the depreciation, depletion and amortization of certain capitalized costs included on the balance sheet. If the final rule retained a single-day, year-end price for determining reserves for accounting purposes (i.e. , for determining depreciation, depletion and amortization), then companies would effectively be required to calculate reserves twice, using two different pricing assumptions—once for disclosure purposes and once for accounting purposes. Similarly, under the full cost rules, the full cost ceiling test, as described in Section III of this release, would have similar implications.

[32] See letters from Apache, API, Audit Quality, BHP, BP, Canadian Natural, CAPP, CFA, Chesapeake, Chevron, Deloitte, Devon, E&Y, EnCana, Energen, Eni, Equitable, Evolution, ExxonMobil, Grant Thornton, Imperial, KPMG, McMoRan, Newfield, Nexen, PEMEX, Petrobras, Petro-Canada, PWC, Questar, Repsol, Ross, Ryder Scott, Sasol, Shell, Southwestern, SPEE, StatoilHydro, Swift, Talisman, Total, and Wagner.

[33] See Rule 4–10.

[34] See letters from Audit Quality, BHP, Canadian Natural, CAPP, Chesapeake, Deloitte, Devon, Evolution, ExxonMobil, Imperial, Newfield, Nexen, Petrobras, Petro-Canada, PWC, Questar, Repsol, Ryder Scott, Shell, Swift, Talisman, Total, and Wagner.

[35] See letters from BP, CFA, Devon, Eni, Nexen, Repsol, and Wagner.

[36] See letters from Apache, Canadian Natural, CAPP, Questar, StatoilHydro, and Wagner.

[37] See letters from Canadian Natural, CAPP, ExxonMobil, Shell, Swift, and Wagner.

[38] See letters from Apache, Audit Quality, BHP, Canadian Natural, CAPP, Chevron, Deloitte, Devon, Eni, Equitable, Evolution, ExxonMobil, Imperial, McMoRan, Newfield, Nexen, Petrobras, Questar, Petro-Canada, PWC, Ryder Scott, Shell, Swift, Total, and Wagner.

[39] See letters from CAPP, CFA, and Devon.

[40] See letters from Apache, Chesapeake, Eni, Equitable, and Imperial.

[41] See letters from CAPP, Devon, Eni, ExxonMobil, Imperial, and Wagner.

[42] See letters from Apache, Audit Quality, CAPP, CFA, Deloitte, E&Y, Energen, Eni, ExxonMobil, Imperial, KPMG, Newfield, PWC, Repsol, and Total.

[43] See letters from API, CAPP, and Shell.

[44] See letters from API, Canadian Natural, EnCana, ExxonMobil, and Total.

not inconsistent with the principles and objectives of financial reporting in authoritative accounting guidance.

With respect to accounting pronouncements that currently make reference to a single-day pricing regime with respect to oil and gas reserves, we are communicating with the FASB staff to align the standards used in its pronouncements with the 12-month average price used in our new rules, as several commenters recommended.[45] As discussed in more detail below, we are adopting a compliance date that will provide sufficient time to coordinate such activities with the FASB. However, as we discuss our revisions with the FASB, we will consider whether to delay the compliance date further.

3. Alternate Pricing Schemes

Some commenters on the Proposing Release believed that oil and gas futures prices, or management's forecast of future prices, would better represent the value of the reserves[46] and be better aligned with fair value of the reserves.[47] They indicated that management uses futures prices, not historical prices, in its planning and day-to-day decision making.[48] They suggested that the use of futures prices, combined with disclosure of how management made the estimates, would provide greater transparency[49] and comparability of disclosure.[50] One noted that historical prices have little to do with a company's future investments and values.[51] Another commenter noted that differentials can be calculated through established accounting procedures under SFAS 157.[52]

However, other commenters argued that futures prices are not available for all reserves locations[53] and that applying differentials to prices would require subjective estimates and reduce comparability among companies.[54] Two commenters noted that standard prices are not consistently available in some geographic regions.[55] Similarly, two commenters were concerned that futures price estimates would have to be accompanied by estimates of future costs, which they thought would be very subjective and not comparable for determining future economic conditions.[56] One commenter asserted that the use of future prices would require companies to document assumptions about future costs, or else the disclosure would be very inconsistent among reporting companies.[57] Three commenters believed that futures prices are more subject to market perceptions than market realities and are seldom used in actual physical trading of oil and gas.[58]

We share the concerns of many of these commenters that determinations of expected future prices could require significant estimations which could fall into a wide, albeit reasonable, range. For example, in many situations and parts of the world, natural gas is sold through longer term contracts where observable market inputs are not widely available. As a result, there could be less comparability among different companies depending on their assumptions, which are inherent in determining futures prices. Difference in assumptions between companies could reduce the comparability of reserves information between those companies.

We believe that the purpose of disclosing reserves estimates is to provide investors with information that is both meaningful and comparable. The reserves estimates in our disclosure rules, however, are not designed to be, nor are they intended to represent, an estimation of the fair market value of the reserves. Rather, the reserves disclosures are intended to provide investors with an indication of the relative quantity of reserves that is likely to be extracted in the future using a methodology that minimizes the use of non-reserves-specific variables. By eliminating assumptions underlying the pricing variable, as any historical pricing method would do, investors are able to compare reserves estimates where the differences are driven primarily by reserves-specific information, such as the location of the reserves and the grade of the underlying resource. We recognize that energy markets are continuing to develop. Therefore, we are not adopting a rule that requires companies to use futures prices to estimate reserves at this time.

4. Time Period Over Which the Average Price Is To Be Calculated

Numerous commenters on the Proposing Release recommended that the 12-month period used to calculate the average price for estimating reserves should not coincide with the fiscal year, as we proposed.[59] Most of these commenters recommended a 12-month period running from the beginning of the fourth quarter of the prior fiscal year through the end of the third quarter of the present fiscal year. For example, for a company with a fiscal year end of December 31, the relevant 12-month period would span from October 1 of the prior year to September 30 of the fiscal year covered by the annual report.[60] Several commenters suggested that we provide a two-month buffer between the end of the measurement period and the end of the company's fiscal year so that reserves estimates would be based on prices from November 1 through October 31 by a company with a fiscal year ending on December 31.[61] Commenters attributed the need for a buffer period to the accelerated filing dates for annual reports[62] and stated that they expected that the additional time would result in better, more accurate disclosure.[63] Others noted that some agreements, like production sharing contracts and other complex concession agreements, can make calculations difficult.[64] One commenter also noted that shifting the relevant measurement period so that it ends three-months prior to the fiscal-year end would align economic calculations with technical calculations, which typically occur at the end of the third quarter.[65]

As noted above, we have considered all of these recommendations. We are adopting a pricing formula based on the average of prices at the beginning of each month in the 12-month period prior to the end of the reporting period. A number of commenters believed that the use of first-of-the-month prices essentially would provide companies with one month more to prepare the reserves disclosures,[66] while still

[45] See letters from Apache, BHP, Canadian Natural, CAPP, CFA, Deloitte, McMoRan, Newfield, Nexen, Questar, Southwestern, Talisman, and Total.

[46] See letters from CFA, Deloitte, Grant Thornton, and McMoRan.

[47] See letters from CFA and Deloitte.

[48] See letters from CFA, Grant Thornton, and McMoRan.

[49] See letter from Deloitte.

[50] See letters from Deloitte and McMoRan.

[51] See letter from McMoRan.

[52] See letter from CFA.

[53] See letters from ExxonMobil and Wagner.

[54] See letters from EnCana, Evolution, ExxonMobil, Newfield, Ryder Scott, and Total.

[55] See letters from Ryder Scott and Total.

[56] See letters from SPE and Total.

[57] See letter from SPE.

[58] See letters from Evolution, Ryder Scott, and Wagner.

[59] See letters from Apache, API, BP, Canadian Natural, CAPP, EnCana, Eni, ExxonMobil, PEMEX, Petro-Canada, Repsol, Ryder Scott, Sasol, Shell, Total, van Wyk, and Wagner.

[60] See letters from Apache, API, BP, Canadian Natural, CAPP, Devon, Eni, ExxonMobil, PEMEX, Petro-Canada, Repsol, Ryder Scott, Sasol, Shell, Total, van Wyk, and Wagner.

[61] See letters from Canadian Natural, CAPP, Eni, Nexen, and Petro-Canada.

[62] See letters from API, Canadian Natural, CAPP, Devon, Evolution, PEMEX, Petrobras, Ryder Scott, Sasol, Shell, Total, and Wagner.

[63] See letters from Canadian Natural, CAPP, Nexen, Petrobras, Petro-Canada, Ryder Scott, Sasol, and Wagner.

[64] See letters from API and Shell.

[65] See letter from Shell.

[66] See letters from API, Devon, Eni, Evolution, ExxonMobil, PEMEX, Petrobras, PWC, Repsol, and Total.

aligning the time period with the fiscal year.[67] We agree with the commenters that such an average will provide companies more time to prepare more accurate disclosure, while still tying the pricing formula to the period covered by the annual report.

C. Extraction of Bitumen and Other Non-Traditional Resources

1. Definition of ''Oil and Gas Producing Activities''

Our current definition of ''oil and gas producing activities'' explicitly excludes sources of oil and gas from ''non-traditional'' or ''unconventional'' sources, that is, sources that involve extraction by means other than ''traditional'' oil and gas wells.[68] These other sources include bitumen extracted from oil sands, as well as oil and gas extracted from coal and shales, even though some of these resources are sometimes extracted through wells, as opposed to mining and surface processing. However, such sources are increasingly providing energy resources to the world due in part to advancements in extraction and processing technology.[69] Therefore, the rules we adopt today revise the definition of ''oil and gas producing activities'' to include such activities.[70]

All commenters on this issue supported including the extraction of unconventional resources as oil and gas producing activities.[71] They believed that such inclusion would greatly improve the quality and completeness of the disclosures.[72] Eight commenters noted that inclusion would better align disclosure with the way that companies view their operations.[73] Some noted that, although the distinction was reasonable decades ago when traditional resources dominated oil and gas production, the reality of today is that such unconventional resources are mainstream and companies invest significant amounts of capital to develop these resources.[74]

The revised definition of ''oil and gas producing activities'' that we adopt today includes the extraction of the non-traditional resources described above.[75] This amendment is intended to shift the focus of the definition of ''oil and gas producing activities'' to the final product of such activities, regardless of the extraction technology used. The amended definition states specifically that oil and gas producing activities include the extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.[76]

Currently, two types of natural resources pose a unique problem to establishing oil and gas reserves. Coal and, to a lesser degree, oil shale are used both as direct fuel and as feedstock to be converted into oil and gas. In response to our request for comment on how best to treat these resources, several commenters recommended that the extraction of coal[77] and oil shale[78] be categorized based on the final product. One commenter noted that investment decisions are based on the value and disposition of the final product.[79] We agree with these commenters and have revised the proposal to require a company to include coal and oil shale that is intended to be converted into oil and gas as oil and gas reserves. The adopted rules also, however, prohibit a company from including coal and oil shale that is not intended to be converted into oil and gas as oil and gas reserves.

2. Disclosure by Final Products

We proposed that disclosure of reserves would be organized based on the pre-processed resource extracted from the ground. For example, under the proposal, a company that extracted bitumen and processed that bitumen into synthetic crude oil in its own processing plant would have had to base its reserves disclosure on the amount of bitumen that was economically producible, not taking into account the economics of the processing plant. This proposal was consistent with our traditional separation of ''upstream'' activities such as drilling and producing oil and gas from ''downstream'' activities such as refining. Distinguishing between traditional resources and unconventional resources can be significant to investors because unconventional resources often involve significantly different economics and company resources than oil and gas from traditional wells.

Several commenters disagreed with our proposal, recommending that the determining factor should be the final product.[80] They believed that a company should be able to consider the prices of self-processed resources when estimating oil and gas reserves because the economics of the processing plant are critical to the registrant's evaluation of the economic producibility of the resources.[81] One commenter was concerned that distinguishing bitumen or other intermediate product from traditional oil and gas creates a false and misleading sense of comparability because producers that upgrade bitumen and sell synthetic crude do not face the same risks and rewards as do producers who sell the bitumen itself.[82]

We are persuaded by these commenters. However, we believe that the distinction between a company's traditional and unconventional activities is an important one from an investor's perspective because many of the unconventional activities are costlier and, therefore, have a much higher threshold of economic producibility. Therefore, we are revising the proposed table in Item 1202 to require separation of reserves based on final product, but distinguishing between final products that are traditional oil or gas from final products of synthetic oil or gas. We believe that with this separate disclosure, investors will be able to identify resources in projects that produce synthetic oil or gas that may be more sensitive to economic conditions from other resources.

In addition, as proposed, we are amending the definition of ''oil and gas producing activities'' to include activities relating to the processing or upgrading of natural resources from which synthetic oil or gas can be

[67] See letters from Devon and ExxonMobil.

[68] See Rule 4–10(a)(1)(ii)(D) [17 CFR 210.4–10(a)(1)(ii)(D)].

[69] Commenters noted that unconventional resources currently represent 45% of natural gas production in the U.S. See letters from American Clean Skies and IPAA.

[70] See Rule 4–10(a)(16) [17 CFR 210.4–10(a)(16)].

[71] See letters from American Clean Skies, Apache, API, Canadian Natural, CAPP, CAQ, CFA, Davis Polk, Devon, E&Y, EnCana, ExxonMobil, FERC, Imperial, IPAA, KPMG, Nexen, Petrobras, Petro-Canada, PRA, PWC, Repsol, Ryder Scott, Sasol, Shell, SPE, StatoilHydro, Talisman, Total, and Wagner.

[72] See letters from API, CAPP, CAQ, ExxonMobil, Imperial, PWC, Repsol, Ryder Scott, Total, and Wagner.

[73] See letters from API, CAQ, E&Y, ExxonMobil, Imperial, Petro-Canada, PWC, and Total.

[74] See letters from Imperial, IPAA, Repsol, and Total.

[75] See Rule 4–10(a)(16) [17 CFR 210.4–10(a)(16)].

[76] A hydrocarbon product is saleable if it is in a state in which it can be sold even if there is no ready market for that hydrocarbon product in the geographic location of the project. The absence of a market does not preclude the activity from being considered an oil and gas producing activity. However, in order to claim reserves for that hydrocarbon product from a particular location, there must be a market, or a reasonable expectation of a market, for that product.

[77] See letters from CAPP, ExxonMobil, Ryder Scott, Sasol, Shell, StatoilHydro, and Wagner.

[78] See letters from CAPP, ExxonMobil, Shell, StatoilHydro, and Wagner.

[79] See letter from ExxonMobil.

[80] See letters from Apache, Nexen, Petrobras, and Ryder Scott.

[81] See letters from Apache, CAQ, and Nexen.

[82] See letter from Nexen.

extracted. However, the definition would continue to exclude:

- Transporting, refining, processing (other than field processing of gas to extract liquid hydrocarbons by the company and the upgrading of natural resources extracted by the company other than oil or gas into synthetic oil or gas) or marketing oil and gas;
- The production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; and
- The production of geothermal steam.

D. Proved Oil and Gas Reserves

We proposed to significantly revise the definition of ''proved oil and gas reserves.'' We are adopting that definition, substantially as proposed.[83] However, as noted above, we have decided to base the price used to establish economic producibility on the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period.

One commenter recommended against using an average price to calculate existing economic conditions if the price is set by contractual arrangements.[84] We agree that under such circumstances, the appropriate price to use for establishing economic producibility is the price set by those contractual arrangements. Therefore, we have revised the definition to reflect that situation.[85]

The existing definition of the term ''proved oil and gas reserves'' incorporates certain specific concepts such as ''lowest known hydrocarbons'' which limit a company's ability to claim proved reserves in the absence of information on fluid contacts in a well penetration,[86] notwithstanding the existence of other engineering and geoscientific evidence.[87] We proposed revisions to the definition that would permit the use of new reliable technologies to establish the reasonable certainty of proved reserves. The proposed revisions to the definition of ''proved oil and gas reserves'' also included provisions for establishing levels of lowest known hydrocarbons and highest known oil through reliable technology other than well penetrations. We are adopting those revisions as proposed.

We also are adopting, as proposed, revisions that permit a company to claim proved reserves beyond those development spacing areas that are immediately adjacent to developed spacing areas if the company can establish with reasonable certainty that these reserves are economically producible.[88] These revisions are designed to permit the use of alternative technologies to establish proved reserves in lieu of requiring companies to use specific tests. In addition, they establish a uniform standard of reasonable certainty that applies to all proved reserves, regardless of location or distance from producing wells.

E. Reasonable Certainty

Both the existing definition of the term ''proved oil and gas reserves,'' and the definition of that term that we are adopting in this release, rely on the term ''reasonable certainty,'' which previously was not defined in Rule 4–10. In the Proposing Release, we proposed to define the term ''reasonable certainty'' as ''much more likely to be achieved than not'' to avoid ambiguity in that term's meaning. However, several commenters recommended that the rules mirror the PRMS definition more closely.[89] Four commenters were concerned that a different definition from the PRMS would cause confusion. They recommended using the PRMS standard of ''high degree of confidence that the quantities will be recovered.''[90] One commenter recommended that, because the proposed definition is new, the Commission should adopt a safe harbor, to avoid potential uncertainty until a court interprets the phrase.[91] But others believed that the proposed definition is consistent with the PRMS definition.[92] One commenter opined that the concept of estimated ultimate recovery (EUR) is appropriate to establish proved oil and gas reserves.[93]

We believe that the terms ''high degree of confidence'' from the PRMS and ''much more likely to be achieved than not'' in our proposal have the same meaning. Our proposed language was not intended to change the level of certainty required to establish reasonable certainty. However, we agree that the use of terminology that is consistent with the PRMS will assist in the understanding of those terms. Therefore, we are adopting the ''high degree of confidence'' standard that exists in the PRMS. We also are clarifying that having a ''high degree of confidence'' means that a quantity is ''much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease'' to provide elaboration to the definition of reasonable certainty.

We are adopting a definition of ''reasonable certainty'' that addresses, and permits the use of, both deterministic methods and probabilistic methods for estimating reserves, as proposed. Nine commenters supported permitting the use of either deterministic methods or probabilistic methods.[94] One commenter believed that each method may be more appropriate for different situations.[95] Other commenters also supported the proposed alignment of the definitions of those terms with the definitions in the PRMS definitions.[96] The definition that we are adopting states that, if deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered.[97] Consistent with the PRMS definition, if probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

F. Developed and Undeveloped Oil and Gas Reserves

We proposed to revise the definitions of the terms ''proved developed oil and gas reserves'' and ''proved undeveloped oil and gas reserves.'' One commenter noted that the terms ''developed'' and ''undeveloped'' are not restricted to proved oil and gas reserves, but could apply to all classifications of reserves, including probable and possible reserves.[98] We agree with that

[83] See Rule 4–10(a)(22) [17 CFR 210.4–10(a)(22)].

[84] See letter from SPE.

[85] See Rule 4–10(a)(22)(v) [17 CFR 210.4–10(a)(22)(v)].

[86] In certain circumstances, a well may not penetrate the area at which the oil makes contact with water. In these cases, the company would not have information on the fluid contact and must use other means to estimate the lower boundary depths for the reservoir in which oil is located.

[87] See previous Rule 4–10(a)(2)(i) [17 CFR 210.4–10(a)(2)(i)].

[88] See Rule 4–10(a)(22) [17 CFR 210.4–10(a)(22)]. See Section II.G for a more detailed discussion regarding this provision.

[89] See letters from EIA, ExxonMobil, and Zakaib.

[90] See letters from Apache, EIA, Energen, and SPE.

[91] See letter from Evolution.

[92] See letters from EnCana, ExxonMobil, Petrobras, and Ryder Scott.

[93] Total.

[94] See letters from Apache, Devon, Evolution, Petro-Canada, Ryder Scott, Shell, SPE, Total, and Wagner.

[95] See letter from Wagner.

[96] See letters from AAPG, SPE, and Southwestern.

[97] See Rule 4–10(a)(24) [17 CFR 210.4–10(a)(24)].

[98] See letter from SPE. We note that with respect to oil and gas reserves, the term ''classification'' is

commenter. Although the development of a prospect may provide the company with more information and data to determine reserves amounts more accurately, companies may estimate proved, probable, and possible volumes regardless of the development stage. In the past, these terms were linked to the concept of proved reserves because our disclosure rules permitted the disclosure only of proved reserves. In light of our revision to allow disclosure of probable and possible reserves, the final rules define the terms ''developed oil and gas reserves'' and ''undeveloped oil and gas reserves'' to indicate that the development status of the reserves is relevant to all classifications of oil and gas reserves.[99]

1. Developed Oil and Gas Reserves

Other than the change discussed above to eliminate ''proved'' from the term being defined, we are adopting a definition of ''developed oil and gas reserves'' substantially as proposed. We proposed to define the term ''proved developed oil and gas reserves'' as proved reserves that:

• In projects that extract oil and gas through wells, can be expected to be recovered through existing wells with existing equipment and operating methods; and

• In projects that extract oil and gas in other ways, can be expected to be recovered through extraction technology installed and operational at the time of the reserves estimate.

Two commenters suggested that, consistent with the PRMS, reserves should be considered developed if the cost of any required equipment is relatively minor compared to the cost of a new well or the installed equipment.[100] Again, we agree that consistency with PRMS would improve compliance with our rules. In addition, such a revision is consistent with our existing definition of the term ''proved undeveloped reserves'' which includes reserves on which a well exists, but a relatively ''major'' expenditure is required for recompletion.[101] Therefore, the final rules provide that reserves also are developed if the cost of any required equipment is relatively minor compared to the cost of a new well.[102]

2. Undeveloped Oil and Gas Reserves

In the Proposing Release, we proposed a significantly revised definition of the term ''proved undeveloped oil and gas reserves.'' The most significant aspect of the proposed revision was the replacement of the existing ''certainty'' test for areas beyond one offsetting drilling unit [103] from a productive well with a ''reasonable certainty'' test. Currently, the definition of the term ''proved undeveloped reserves'' imposes a ''reasonable certainty'' standard for reserves in drilling units immediately adjacent to the drilling unit containing a producing well and a ''certainty'' standard for reserves in drilling units beyond the immediately adjacent drilling units.[104] All commenters on this issue supported the proposal.[105] Three commenters noted that a single standard-reasonable certainty-should apply to all proved reserves.[106] We are adopting this aspect of the definition as proposed.

Many commenters opposed the proposed language that would have imposed a five-year limit on maintaining undeveloped reserves unless ''unusual'' circumstances existed.[107] They asserted that large projects, projects in remote areas, and projects in continuous accumulations, such as oil sands, typically take more than five years to develop, but they do not view such projects as ''unusual.'' [108] One commenter noted that the proposed rule is not consistent with the PRMS, which uses the term ''specific circumstances,'' rather than ''unusual circumstances.'' [109] Other commenters suggested that we require the company to explain why it has not developed any undeveloped reserves for more than five years.[110] The intent of the proposal was not to exclude projects that typically take more than five years to develop from being considered reserves. We agree that the rule should allow the recognition of reserves in projects that are expected to run more than five years, regardless of whether ''unusual'' circumstances exist. Therefore, we have revised the rule to replace the term ''unusual'' with the term ''specific.'' [111] We note that, as proposed, Item 1203 of Regulation S–K would require disclosure regarding why such undeveloped reserves have not been developed.[112]

We also proposed to broaden the definition of the term ''proved undeveloped reserves'' to permit a company to include, in its undeveloped reserves estimates, quantities of oil that can be recovered through improved recovery projects and to expand the technologies that a company can use to establish reserves. Under the existing definition, a company can include such quantities only if techniques have been proved effective by actual production from projects in the area and in the same reservoir. As proposed, we are expanding this definition of the term ''undeveloped oil and gas reserves'' to permit the use of techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or ''by other evidence using reliable technology that establishes reasonable certainty.'' [113]

We also are making other, less substantive revisions to the definition of ''undeveloped oil and gas reserves.'' First, commenters suggested that we use the term ''development spacing'' [114] or ''drainage areas'' [115] instead of ''drilling units'' because the term ''drilling units'' is only relevant in jurisdictions that establish such units. They noted that many foreign jurisdictions do not establish such units. We concur with those commenters and have replaced the term ''drilling units'' with the term ''development spacing areas.''

One commenter also noted that the PRMS guidance on the use of analogs for improved recovery projects does not limit such use to ''within the immediate area'' and recommended that we delete this phrase from the definition.[116] Again, we agree that consistency with PRMS would be beneficial in this instance and have deleted that phrase

used to indicate the level of certainty that estimated amounts will be recovered. Thus, although the terms ''developed'' and ''undeveloped'' may be considered means in which to generically ''classify'' reserves, for clarity, we use that term to be consistent with industry usage.

99 See Rules 4–10(a)(6) and (31) [17 CFR 210.4–10(a)(6) and (31)].

100 See letters from SPE and Total.

101 See previous Rule 4–10(a)(4) [17 CFR 210.4–10(a)(4)].

102 See Rule 4–10(a)(6) [17 CFR 210.4–10(a)(6)].

103 As noted later in this section of the release, we are replacing the term ''drilling unit'' with the term ''development spacing area'' in the final rules. However, for purposes of discussing the proposal and the existing rules, we continue to use the term ''drilling unit'' because that is the term used in the proposal and the existing rules.

104 See previous Rule 4–10(a)(4) [17 CFR 210.4–10(a)(4)]. A drilling unit refers to the spacing between wells required by some local jurisdictions to prevent wasting resources and optimize recovery.

105 See letters from American Clean Skies, Apache, API, Canadian Natural, CAPP, Chesapeake, Devon, Evolution, ExxonMobil, McMoRan, Petro-Canada, Questar, Repsol, Southwestern, Shell, SPE, Total, and Wagner.

106 See letters from Devon, EnCana, and Equitable.

107 See letters from American Clean Skies, Apache, CAPP, Chesapeake, EnCana, ExxonMobil, Luscher, Newfield, Nexen, Petrobras, Petro-Canada, Ryder Scott, Shell, SPE, and Total.

108 See letters from American Clean Skies, CAPP, Chesapeake, EnCana, ExxonMobil, Newfield, Nexen, Petrobras, Petro-Canada, Ryder Scott, Shell, and Total.

109 See letter from SPE.

110 See letters from Devon, Ryder Scott, and Wagner.

111 See Rule 4–10(a)(31) [17 CFR 210.4–10(a)(31)].

112 See Item 1203(d) [17 CFR 229.1203(d)].

113 See Rule 4–10(a)(31) [17 CFR 210.4–10(a)(31)].

114 See letter from Total.

115 See letter from SPE.

116 See letter from SPE.

from the definition. We also have eliminated two paragraphs of the proposed definition because they were largely repetitive of other aspects of the definition and were unnecessary.[117]

G. Reliable Technology

1. Definition of the Term ''Reliable Technology''

We are adopting, substantially as proposed, a new definition of ''reliable technology'' that would broaden the types of technologies that a company may use to establish reserves estimates and categories. All commenters on this topic supported the proposed principles-based definition for reliable technology.[118]

The current rules limit the use of alternative technologies as the basis for determining a company's reserves disclosures. For example, under the current rules, a company must use actual production or flow tests to meet the ''reasonable certainty'' standard necessary to establish the proved status of its reserves.[119] Similarly, the current rules provide bright line tests for determining fluid contacts, such as lowest known hydrocarbons and highest known oil, which establish the volume of the hydrocarbons in place.

We recognize that technologies have developed, and will continue to develop, improving the quality of information that can be obtained from existing tests and creating entirely new tests that we cannot yet envision. Thus, the new definition of the term ''reliable technology'' permits the use of technology (including computational methods) that has been field tested and has demonstrated consistency and repeatability in the formation being evaluated or in an analogous formation. This new standard will permit the use of a new technology or a combination of technologies once a company can establish and document the reliability of that technology or combination of technologies.

We are adopting certain revisions to our proposed definition of the term ''reliable technology.'' The proposal also would have required reliable technology to be ''widely accepted.'' However, some commenters were concerned that this requirement would exclude proprietary technologies that companies develop internally that have proven to be reliable.[120] We concur with these commenters and have removed the ''widely accepted'' requirement from the final rule.

We also proposed to define the term ''reliable technology,'' expressed in probabilistic terms, as technology that has been proven empirically to lead to correct conclusions in 90% or more of its applications. Several commenters expressed concern that this proposed 90% threshold would be difficult to verify and support on an ongoing basis.[121] We agree that a bright line test would be difficult to apply to a particular technology or mix of technologies to determine their reliability. Therefore, we are not adopting the 90% threshold as part of the definition.

2. Disclosure of Technologies Used

The proposal would have required a company to disclose the technology used to establish reserves estimates and categories for material properties in a company's first filing with the Commission and for material additions to reserves estimates in subsequent filings because, under the proposal, a company would be able to select the technology or mix of technologies that it uses to establish reserves. Two commenters supported the proposal because they believed that disclosure of the technologies used is reasonable if the definition of ''reliable technology'' is principles-based.[122] However, many other commenters were concerned that the proposed requirement to disclose the technologies used to establish levels of certainty for reserves estimates would lead to very complex, technical disclosures that would have little meaning to investors.[123] Others were concerned that disclosure of the technology, or the mix of technologies, might cause competitive harm.[124]

As an alternative, some commenters recommended that the rule require a more general overview of the technologies used.[125] We are clarifying that the required disclosure would be limited to a concise summary of the technology or technologies used to create the estimate.[126] A company would not be required to disclose proprietary technologies, or a proprietary mix of technologies, at a level of specificity that would cause competitive harm. Rather, the disclosure may be more general. For example, a company may disclose that it used a combination of seismic data and interpretation, wireline formation tests, geophysical logs, and core data to calculate the reserves estimate. As noted, however, the Commission's staff, as part of the review and comment process, may continue to request companies to provide supplemental data, consistent with current practice,[127] which, under the new rules, may include information sufficient to support a company's conclusion that a technology or mix of technologies used to establish reserves meets the definition of ''reliable technology.''

Two commenters supported the proposal to limit the disclosures to technologies used to establish reserves in a company's first filing with the Commission and material additions to reserves.[128] We are adopting this limitation as proposed.[129] If the company has not previously disclosed reserves estimates in a filing with the Commission or is disclosing material additions to its reserves estimates, the company must disclose the technologies used to establish the appropriate level of certainty for reserves estimates from material properties included in the total reserves disclosed and the particular properties do not need to be identified. We believe that requiring such disclosure when reserves, or material additions to reserves, are reported for the first time will discourage the use of questionable technologies to establish reserves. However, we do not believe it is necessary to require a company to disclose the technology or technologies

[117] These paragraphs would have clarified (1) in a conventional accumulation, offsetting productive units must lie within an area in which economic producibility has been established by reliable technology to be reasonably certain and (2) proved reserves can be claimed in a conventional or continuous accumulation in a given area in which engineering, geoscience, and economic data, including actual drilling statistics in the area, and reliable technology show that, with reasonable certainty, economic producibility exists beyond immediately offsetting drilling units. We do not believe that these statements, based on the terms ''conventional accumulation'' and ''continuous accumulation'' which are no longer being defined continue to serve a helpful purpose. See Section II.J.5 of this release.

[118] See letters from AAPG, American Clean Skies, Apache, CFA, Davis Polk, Devon, EnCana, ExxonMobil, Petrobras, Ryder Scott, Sasol, Shell, SPE, Southwestern, and Wagner.

[119] However, in the past, the Commission's staff has recognized that flow tests can be impractical in certain areas, such as the Gulf of Mexico, where environmental restrictions effectively prohibit these types of tests. The staff has not objected to disclosure of reserves estimates for these restricted areas using alternative technologies.

[120] See letters from Chesapeake, ExxonMobil, Shell, and Total.

[121] See letters from AAPG, Apache, EIA, Evolution, Ryder Scott, Shell, SPE, and Wagner.

[122] See letters from Davis Polk and Sasol.

[123] See letters from API, Devon, Eni, ExxonMobil, PEMEX, Petro-Canada, Questar, Repsol, Ryder Scott, Shell, Southwestern, StatoilHydro, and Total.

[124] See letters from API, Devon, Evolution, ExxonMobil, Ryder Scott, StatoilHydro, and Total.

[125] See letters from EnCana, Eni, Evolution, Ryder Scott, and Shell.

[126] See Item 1202(a)(6) [17 CFR 229.1202(a)(6)].

[127] Currently, the Commission's staff requests supplemental data pursuant to Instruction 4 to Item 102 of Regulation S–K [17 CFR 229.102], Rule 418 [17 CFR 230.418], and Rule 12b–4 [17 CFR 240.12b–4]

[128] See letters from Southwestern and Wagner.

[129] See Item 1202(a)(6) [17 CFR 229.1202(a)(6)].

relied upon to establish reserves previously disclosed under our rules because the permitted technologies have been limited to those permitted by our existing rule. In addition, we believe that ongoing disclosure of the technologies used to establish all of a company's reserves would become unnecessarily cumbersome.

H. Unproved Reserves—''Probable Reserves'' and ''Possible Reserves''

As discussed more fully in Section IV.B.3 of this release addressing the disclosure requirements of new Subpart 1200, we are adopting the proposal to permit disclosure of probable and possible reserves. Therefore, we are adopting the proposed definitions of the terms ''probable reserves'' and ''possible reserves'' as proposed.

When producing an estimate of the amount of oil and gas that is recoverable from a particular reservoir, a company can make three types of estimates:

- An estimate that is reasonably certain;
- An estimate that is as likely as not to be achieved; and
- An estimate that might be achieved, but only under more favorable circumstances than are likely.

These three types of estimates are known in the industry as (1) proved, (2) proved plus probable, and (3) proved plus probable plus possible reserves estimates.

1. Probable Reserves

We are adopting the definition of the term ''probable reserves'' as proposed. It states that ''probable reserves'' are those additional reserves that are less certain to be recovered than proved reserves but which, in sum with proved reserves, are as likely as not to be recovered.[130] This definition provides guidance for the use of both deterministic and probabilistic methods. The definition clarifies that, when deterministic methods are used, it is as likely as not that actual remaining quantities recovered will equal or exceed the sum of estimated proved plus probable reserves. Similarly, when probabilistic methods are used, there must be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates. This definition was derived from the PRMS definition of the term ''probable reserves.'' Several commenters agreed with the proposed definition of this term, noting that it is roughly consistent with PRMS.[131]

[130] See Rule 4–10(a)(18) [17 CFR 210.4–10(a)(18)].

[131] See letters from Devon, EnCana, SPE, and StatoilHydro.

2. Possible Reserves

We also are adopting the definition of the term ''possible reserves'' as proposed. The new definition states that possible reserves include those additional reserves that are less certain to be recovered than probable reserves.[132] It clarifies that, when deterministic methods are used, the total quantities ultimately recovered from a project have a low probability to exceed the sum of proved, probable, and possible reserves. When probabilistic methods are used, there must be at least a 10% probability that the actual quantities recovered will equal or exceed the sum of proved, probable, and possible estimates. Several commenters noted that our proposed definition of the term ''possible reserves'' was consistent with PRMS, which also uses a 10% threshold.[133] One commenter recommended that the threshold for ''possible reserves'' should be a 25% likelihood of recovery because that percentage would be more meaningful than 10%.[134] We believe that a definition consistent with the PRMS will provide the most certainty and clarity for companies and investors.

I. Reserves

We proposed to add a definition of the term ''reserves'' to our rules. The proposed definition would have described the criteria that an accumulation of oil, gas, or related substances must satisfy to be considered reserves (of any classification), including non-technical criteria such as legal rights. Specifically, we proposed to define reserves as the estimated remaining quantities of oil and gas and related substances anticipated to be recoverable, as of a given date, by application of development projects to known accumulations based on:

- Analysis of geoscience and engineering data;
- The use of reliable technology;
- The legal right to produce;
- Installed means of delivering the oil, gas, or related substances to markets, or the permits, financing, and the appropriate level of certainty (reasonable certainty, as likely as not, or possible but unlikely) to do so; and
- Economic producibility at current prices and costs.

The proposed definition also would have clarified that reserves are classified as proved, probable, and possible according to the degree of uncertainty associated with the estimates. We are not adopting the definition as proposed. Four commenters recommended clarification that the term ''legal right to produce'' extends beyond the initial term of an oil and gas concession if there is a reasonable expectation that the concession will be renewed, consistent with the PRMS and current staff position.[135] We are adopting a definition of the term ''reserves'' that more closely parallels the PRMS definition of that term.

[132] See Rule 4–10(a)(17) [17 CFR 210.4–10(a)(17)].

[133] See letters from Devon, EnCana, SPE, and StatoilHydro.

[134] See letter from Evolution.

Our final rules define the term ''reserves'' as the estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations.[136] In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production of oil and gas, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

A note to the definition clarifies that reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible and that reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (*i.e.*, absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (*i.e.*, potentially recoverable resources from undiscovered accumulations).[137]

One notable difference between our final definition of ''reserves'' and the PRMS definition is that our definition is based on ''economic producibility'' rather than ''commerciality.'' One commenter believed that reserves must be ''commercial,'' as stated in the PRMS definition.[138] However, commerciality introduces a subjective aspect to the price used to establish existing economic conditions by factoring in the rate of return required by a particular company before it will commit resources to the project. This rate of return will vary among companies, reducing the comparability among disclosures. Therefore, the adopted definition of the term ''reserves'' relies on economic producibility, as proposed.

[135] See letters from API, CAQ, Grant Thornton, and KPMG.

[136] See Rule 4–10(a)(26) [17 CFR 210.4–10(a)(26)].

[137] See Note to Rule 4–10(a)(26) [17 CFR 210.4–10(a)(26)].

[138] See letter from StatoilHydro.

J. Other Supporting Terms and Definitions

We also proposed to define several other terms primarily to support and clarify the definitions of the key terms. We are adopting most of those supporting definitions as discussed in further detail below.

1. Deterministic Estimate

A company can derive two different types of reserves estimates depending on the method used to calculate the estimates. These two types of estimates are known as ''deterministic estimates'' and ''probabilistic estimates.'' [139] In the Proposing Release, we proposed to define the term ''deterministic estimate'' as an estimate based on a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation that is used in the reserves estimation procedure. We are adopting that definition as proposed.

2. Probabilistic Estimate

We are adopting a new definition of the term ''probabilistic estimate'' substantially as proposed. The new rule defines the term ''probabilistic estimate'' as an estimate that is obtained when the full range of values that could reasonably occur from each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.[140] In response to a comment received, however, we revised the definition so that it does not include the application of a range of values with respect to economic conditions because those conditions, such as prices and costs, are based on historical data, and therefore are an established value, rather than a range of estimated values.[141]

3. Analogous Reservoir

We proposed a definition of the term ''analogous formation in the immediate area.'' As noted above, we received comment indicating that the use of appropriate analogs should not be limited to the immediate area in which the reserves are being estimated.[142] Therefore, we have changed the defined term to ''analogous reservoir.'' [143] In addition, based on commenters' remarks, we are defining the term ''analogous reservoir'' in a manner that is more consistent with the PRMS, which addresses more specifically the types of reservoirs that may be used as analogues. The new definition of the term ''analogous reservoir'' states that analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery.[144] When used to support proved reserves, an ''analogous reservoir'' refers to a reservoir that shares the following characteristics with the reservoir of interest:

- Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
- Same environment of deposition;
- Similar geological structure; and
- Same drive mechanism.

As proposed, the new definition includes an instruction that clarifies that reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest. The new definition also clarifies that, although an analogous reservoir must be in the same geological formation as the reservoir of interest, it need not be in pressure communication with the reservoir of interest.

4. Definitions of Other Terms

We received no comment with regard to several of the proposed supporting definitions. We are adopting those definitions substantially as proposed without material changes. They include the following terms:

- ''Condensate''; [145]
- ''Development project''; [146]
- ''Economically producible''; [147]
- ''Estimated ultimate recovery,'' [148]
- ''Exploratory well''; [149]
- ''Extension well''; [150] and
- ''Resources.'' [151]

Most of these supporting terms and their definitions are based on similar terms in the PRMS. The definition of ''resources'' is based on the Canadian Oil and Gas Evaluation Handbook (COGEH).

In the Proposing Release, we solicited comment on whether we should adopt any other supporting definitions. One commenter submitted an appendix to its letter containing numerous other terms that it thought we should adopt.[152] We have decided not to adopt those additional definitions because we feel that they are unnecessary at this time. However, we have decided to adopt a definition for the term ''bitumen.'' We believe that providing a definition for this term will lead to more consistency among disclosures because there currently are several competing definitions of that term used in the industry.

We are defining the term ''bitumen'' as ''petroleum in a solid or semi-solid state in natural deposits. In its natural state, it usually contains sulfur, metals, and other non-hydrocarbons. Bitumen has a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis.'' [153] This definition is similar to the PRMS definition of ''natural bitumen.''

5. Proposed Terms and Definitions Not Adopted

We proposed definitions for the terms ''continuous accumulations'' and ''conventional accumulations'' to assist companies in disclosing segregated reserves based on these two types of accumulations. As noted elsewhere in this release, the final rules do not require disclosure based on the type of accumulation in which the reserves are found.[154] Therefore, there is no need to define these terms and we are not adopting the proposed definitions.

Similarly, we proposed a definition for the term ''sedimentary basin'' because it would have been part of our definition of the term ''by geographic area.'' As noted elsewhere in this release, we have substantially revised the definition of the term ''by geographic area'' [155] and the term ''sedimentary basin'' is no longer needed, so we are not adopting this proposed term and definition.

As noted above, one commenter recommended that we adopt a large glossary of terms and definitions that correspond with the PRMS definitions.[156] Rather than defining an extensive glossary of terms in our rules

[139] See Rules 4–10(a)(5) and (a)(19) [17 CFR 210.4–10(a)(5) and (a)(19)]. These definitions are based on the Canadian Oil and Gas Evaluation Handbook (COGEH). This handbook was developed by the Calgary Chapter of the Society of Petroleum Evaluation Engineers and the Petroleum Society of CIM to establish standards to be used within the Canadian oil and gas industry in evaluating oil and gas reserves and resources.

[140] See Rule 4–10(a)(19) [17 CFR 210.4–10(a)(19)].

[141] See letter from Shell.

[142] See letter from SPE.

[143] See Rule 4–10(a)(2) [17 CFR 210.4–10(a)(2)].

[144] See Rule 4–10(a)(2) [17 CFR 210.4–10(a)(2)].

[145] See Rule 4–10(a)(4) [17 CFR 210.4–10(a)(4)].

[146] See Rule 4–10(a)(8) [17 CFR 210.4–10(a)(8)].

[147] See Rule 4–10(a)(10) [17 CFR 210.4–10(a)(10)].

[148] See Rule 4–10(a)(11) [17 CFR 210–4–10(a)(11)].

[149] See Rule 4–10(a)(13) [17 CFR 210.4–10(a)(13)].

[150] See Rule 4–10(a)(14) [17 CFR 210.4–10(a)(14)].

[151] See Rule 4–10(a)(28) [17 CFR 210.4–10(a)(28)].

[152] See letter from SPE.

[153] See Rule 4–10(a)(3) [17 CFR 210.4–10(a)(3)].

[154] See Section III.B.3.c.

[155] See Section III.B.2.a.

[156] See letter from SPE.

and attempting to constantly update those definitions, we advise companies to look to definitions that are commonly accepted within the oil and gas industry to the extent such definitions are not in, or inconsistent with, our rules.

K. Alphabetization of the Definitions Section of Rule 4–10

We are alphabetizing the definitional terms in Rule 4–10(a) because we are adding a significant number of defined terms to this section.

III. Revisions to Full Cost Accounting and Staff Accounting Bulletin

As we noted in Section II.B.2 of this release, commenters unanimously opposed our proposal to use different prices for disclosure and accounting purposes. We agree with those commenters and are revising our proposal to use a 12-month average price for accounting purposes. These revisions primarily will appear under the full cost accounting method described in Rule 4–10(c) [157] of Regulation S–X. The full cost accounting method permits certain oil and gas extraction costs to accumulate on a company's balance sheet subject to a limitation test or a ''ceiling'' as described in Rule 4–10(c)(3)(4). Like reserve disclosures, these capitalized costs and the related limitation test are not fair value based measurements. Rather the capitalized costs represent the accumulated historical acquisition, exploration and development costs (net of any previously recorded depletion, amortization or ceiling test write downs) incurred for oil and gas producing activities, limited to a standardized mathematical calculation (the full cost ceiling) adopted over 25 years ago. Costs that do not exceed the limitation are deferred and amortized over time. The limitation test calculation on capitalized costs is not designed or intended to represent a fair valuation of the related oil and gas assets.[158]

Similar to the single-day, year-end pricing used under the successful efforts method,[159] the application of the full cost method of accounting in Rule 4–10(c) has used ''current prices,'' interpreted as single-day, year-end prices, as the basis for calculating the limitation on costs that may be capitalized under the full cost method. In order to further the objective of providing comparable oil and gas reserve quantities, our final rule clarifies that the term ''current prices'' as used in Rule 4–10(c) is consistent with the 12-month average price as calculated in Rule 4–10(a)(22)(v).[160]

However, since these calculations are not designed to result in a calculation of fair value and since the change to the full cost accounting method would effectively eliminate the anomalies caused by the single-day, year-end price currently used in the limitation test, the SEC staff will eliminate portions of Staff Accounting Bulletin (SAB) Topic 12:D.3.c that permit consideration of the impact of price increases subsequent to the period end on the ceiling limitation test.

The combination of adopting a 12-month average pricing mechanism and eliminating portions of SAB Topic 12:D.3.c could have the effect of requiring a company using the full cost accounting method to record a ceiling test write-down in income during periods of rising oil and gas prices. In that situation, it is possible that using a 12-month average price in the ceiling test calculation might result in a write-down that would not otherwise have been required had the full cost company been permitted to use the single-day, year-end price. Conversely, it is also possible that in periods of declining oil and gas prices, the application of this rule could result in the deferral of ceiling test write-downs. In that situation, it is possible that using a 12-month average price in the ceiling limitation test calculation might not result in a write-down in situations where a write down would have otherwise been required had the full cost company been required to use a single-day, year-end price in its ceiling limitation test calculation.

Because the application of the ceiling limitation test is not a fair-value-based calculation but rather a limit on the amount of certain oil and gas related exploration costs that can be capitalized, portions of which would have resulted in write-downs in prior periods under other methods of accounting, we believe the benefits of using a single pricing mechanism justify the potential changes to the timing of those ceiling test write-downs or amortizations amounts. However, as discussed in Section V of this release, we believe that the company should discuss such situations, if material, particularly when pricing trends indicate the possibility of future write-downs, in Management's Discussion and Analysis and, where appropriate, the notes to the financial statements.

IV. Update and Codification of the Oil and Gas Disclosure Requirements in Regulation S–K

The Proposing Release proposed to update and codify Securities Act and Exchange Act Industry Guide 2: Disclosure of Oil and Gas Operations (Industry Guide 2).[161] Industry Guide 2 currently sets forth most of the disclosures that an oil and gas company provides regarding its reserves, production, property, and operations. Regulation S–K references Industry Guide 2 in Instruction 8 to Item 102 (Description of Property), Item 801 (Securities Act Industry Guides), and Item 802 (Exchange Act Industry Guides). However, Industry Guide 2 itself does not appear in Regulation S–K or in the Code of Federal Regulations. The rules that we adopt today codify the contents of Industry Guide 2 in a new Subpart 1200 of Regulation S–K.

A. Revisions to Items 102, 801, and 802 of Regulation S–K

The instructions to Item 102 of Regulation S–K, as well as Items 801 and 802 of Regulation S–K, currently reference the industry guides. Because we are codifying the Industry Guide 2 disclosures in a new Subpart 1200 of Regulation S–K, we are revising the instructions to Item 102 to reflect this change.[162] We also are eliminating the references in Items 801 and 802 to Industry Guide 2 because that industry guide will cease to exist upon effectiveness of the amendments we adopt today.[163]

In addition, Instruction 5 to Item 102 of Regulation S–K currently prohibits the disclosure of reserves other than proved oil and gas reserves. Because we are adopting rules to permit disclosure of probable and possible oil and gas reserves, we are revising Instruction 5 to limit its applicability to extractive enterprises other than oil and gas producing activities, such as mining activities.[164] Similarly, Instruction 3 of

[157] 17 CFR 210.4–10(c).

[158] While not intended to represent fair value, costs that are written down because they exceed the ceiling limitation are accounted for in the same manner as impairments recognized under accounting generally. That is, once the asset is written down, it becomes the new historical cost basis and cannot be reinstated for subsequent increases in the ceiling. See Rule 4–10(c)(4)(i) of Regulation S–X [17 CFR 210–4–10(c)(4)(i)].

[159] The accounting guidance refers to our definition of proved reserves under existing Rule 4–10(a)(2), which currently uses a single-day, year-end price to establish reserves amounts.

[160] See Rule 4–10(c)(8) [17 CFR 210.4–10(c)(8)].

[161] Exchange Act Industry Guide 2 merely references, and therefore is identical to, Securities Act Industry Guide 2.

[162] See revised Instructions 4 and 8 to Item 102 [17 CFR 229.102].

[163] See revised Item 801 and 802 [17 CFR 229.801 and 802].

[164] See revised Instruction 5 to Item 102 [17 CFR 229.102]. Extractive enterprises include enterprises such as mining companies that extract resources from the ground.

Item 102, regarding production, reserves, locations, development and the nature of the company's interests, will no longer apply to oil and gas producing activities, so we also are limiting that instruction to mining activities.[165]

Finally, we are eliminating Instruction 4 to Item 102 regarding the ability of the Commission's staff to request supplemental information, including reserves reports. This instruction is duplicative of Securities Act Rule 418 [166] and Exchange Act 12b–4,[167] regarding the staff's general ability to request supplemental information.

B. Proposed New Subpart 1200 to Regulation S–K Codifying Industry Guide 2 Regarding Disclosures by Companies Engaged in Oil and Gas Producing Activities

1. Overview

We are adding a new Subpart 1200 to Regulation S–K that codifies the disclosure requirements related to companies engaged in oil and gas producing activities. This new subpart largely includes the existing requirements of Industry Guide 2. However, we have revised these requirements to update them, provide better clarity with respect to the level of detail required in oil and gas disclosures, including the geographic areas by which disclosures need to be made, and provide formats for tabular presentation of these disclosures. In addition, Subpart 1200 contains the following new disclosure requirements, many of which have been requested by industry participants:

- Disclosure of reserves from non-traditional sources (*e.g.*, bitumen, shale, coal) as oil and gas reserves;
- Optional disclosure of probable and possible reserves;
- Optional disclosure of oil and gas reserves' sensitivity to price;
- Disclosure of the development of proved undeveloped reserves;
- Disclosure of technologies used to establish additions to reserves estimates;
- Disclosure of a company's internal controls over reserves estimation and the qualifications of the business entity or individual preparing or auditing the reserves estimates; and
- Disclosure based on a new definition of the term ''by geographic area.''

We discuss each of these proposed new Items below.

2. Item 1201 (General Instructions to Oil and Gas Industry-Specific Disclosures)

We are adding new Item 1201 to Regulation S–K. This item sets forth the general instructions to Subpart 1200. The new item contains three paragraphs that perform the following tasks:

- Instruct companies for which oil and gas producing activities are material to provide the disclosures specified in Subpart 1200; [168]
- Clarify that, although a company must present specified Subpart 1200 information in tabular form, the company may modify the format of the table for ease of presentation, to add additional information or to combine two or more required tables;
- State that the definitions in Rule 4–10(a) of Regulation S–X apply to Subpart 1200; and
- Define the term ''by geographic area.''

a. Geographic Area

We received significant comments regarding the proposed definition of the term ''by geographic area.'' We proposed to require disclosure by continent, country containing 15% of more of the company's reserves, and sedimentary basin or field containing 10% or more of the company's reserves. Several commenters were concerned that the proposed definition would add too much detail to the disclosures, particularly at the basin or field level.[169] They were concerned that this amount of detail would make disclosures too complex and incoherent.[170] They were particularly concerned with the extension of this standard to disclosures other than reserves, such as production, wells, and acreage.[171] Commenters also believed that the disclosures, in particular by field, could cause competitive harm in future property sales transactions, unitization agreements, and other asset transfers.[172]

Some commenters also believed that some of these disclosures may be prohibited by foreign governments.[173] One commenter noted that separate determination of field or basin reserves within a larger production sharing agreement may not be possible due to concession-wide cost sharing terms.[174] Eight commenters recommended that the determination of appropriate geographic disclosure should remain with management, consistent with Statement of Financial Accounting Standard No. 69 (SFAS 69).[175] However, two commenters indicated that a country-by-country breakdown would be adequate.[176]

Four commenters supported the proposed percentage thresholds for geographic disclosure, stating that they would increase understanding of the total energy supply, leading to better decisions by policy makers.[177] One commenter supported the 15% threshold for countries.[178]

As we noted in the Proposing Release, there have been differing interpretations among oil and gas companies as to the level of specificity required when a company is breaking out its reserves disclosures based on geographic area as required by Instruction 3 of Item 102 of Regulation S–K.[179] Some companies currently broadly organize their reserves only by hemisphere or continent. SFAS 69 requires reserves disclosure to be separately disclosed for the company's home country and foreign geographic areas. It defines ''foreign geographic areas'' as ''individual countries or groups of countries as appropriate for meaningful disclosure in the circumstances.'' Since SFAS 69 was issued, the operations of oil and gas companies have become much more diversified globally. For many large U.S. oil and gas producers, the majority of reserves are now overseas, with material amounts in individual countries and even individual fields or basins.

We think that greater specificity than simply disclosing reserves within ''groups of countries'' would benefit investors and, in certain cases, may be necessary to meet the requirements of Item 102 of Regulation S–K. Some countries in which many of these companies operate and may have significant reserves are subject to unique risks, such as political instability.

[165] See revised Instruction 3 to Item 102 [17 CFR 229.102].

[166] 17 CFR 230.418.

[167] 17 CFR 240.12b–4.

[168] This paragraph would maintain the existing exclusion in Industry Guide 2 for limited partnerships and joint ventures that conduct, operate, manage, or report upon oil and gas drilling or income programs, that acquire properties either for drilling and production, or for production of oil, gas, or geothermal steam or water.

[169] See letters from Apache, CAPP, Devon, ExxonMobil, Imperial, Nexen, Repsol, Shell, and StatoilHydro.

[170] See letters from Apache, CAPP, ExxonMobil, Imperial, Nexen, and Repsol.

[171] See letters from ExxonMobil, Imperial, and Total.

[172] See letters from Apache, API, BHP, Canadian Natural, CAPP, Devon, EnCana, Eni, Newfield, Nexen, Petro-Canada, Shell, StatoilHydro, and Total.

[173] See letters from Apache, API, CAPP, Eni, Newfield, Petro-Canada, and Total.

[174] See letter from Apache.

[175] See letters from Apache, API, Canadian Natural, CAPP, Eni, ExxonMobil, Imperial, and Petro-Canada.

[176] See letters from ExxonMobil and Nexen.

[177] See letters from AAPG, CFA, Chesapeake, and E&Y.

[178] See letter from Shell.

[179] 17 CFR 229.102.

However, we recognize that disclosure that is too detailed may detract from the overall disclosure. Thus, we have revised the definition of the term ''by geographic area'' to mean, as appropriate for meaningful disclosure under a company's particular circumstances:

(1) By individual country;

(2) By groups of countries within a continent; or

(3) By continent.[180]

This definition is substantially the same as the definition currently provided in SFAS 69. However, as proposed, we are adopting specific percentage thresholds to the geographic breakdowns of reserves estimates and production. With respect to production, the final rules require disclosure of production in each country or field containing 15% or more of the company's proved reserves unless prohibited by the country in which the reserves are located. We are raising the proposed 10% threshold for field disclosure of production to 15% to make the threshold consistent. However, rather than requiring disclosure based on a percentage of the amount of the company's reserves of an individual product, as proposed, the final rules require disclosure based on a percentage of a company's total global oil and gas proved reserves, based on barrels of oil equivalent.[181]

With respect to reserves estimates, the final rules require disclosure of reserves in countries containing more than 15% of the company's proved reserves. As with the production disclosure, this 15% threshold would be based on the company's total global oil and gas proved reserves, rather than on individual products, as proposed.[182] A registrant need not provide disclosure of the reserves in a country containing 15% or more of the registrant's proved reserves if that country's government prohibits disclosure of reserves in that country.

We are not adopting the requirement that we proposed to disclose reserves by sedimentary basin or field. We share commenters' concerns that there is potential for competitive harm from such disclosure in future property sales transactions, unitization agreements, and other asset transfers. Moreover, we recognize that there may be situations in which a particular field may encompass a significant portion of a company's reserves in a foreign country. To avoid compelling a company to provide, in effect, field disclosure, the rule does not require disclosure of reserves in a country containing 15% of the company's reserves if that country prohibits disclosure of reserves in a particular field and disclosure of reserves in that country would have the effect of disclosing reserves in particular fields.[183] For example, if a company has 25% of its reserves in Country A and Country A's government prohibits disclosure of reserves by field within Country A, if almost all of that company's reserves in Country A are located in a single field, the company would not be required to specify the amount of its reserves located in Country A.

b. Tabular Disclosure

We proposed to require much of the reserves disclosures and other disclosures in Industry Guide 2 to be presented in tabular format. Two commenters encouraged using a standardized table for reserves disclosure.[184] Another believed that companies should be able to reorganize, supplement, or combine tables for better presentation of the company's strategy.[185] However, two commenters believed that the rules should not propose a specified tabular format in general.[186] These commenters believed that companies should have the flexibility to present data in a format that is most relevant and meaningful to investors, whether it is tabular or narrative.[187] We continue to believe that in certain circumstances, the required disclosures lend themselves to a tabular disclosure format. We believe that standardizing such tables will improve the readability and comparability of disclosures among companies. However, in response to comments received, we have made several revisions to the individual disclosure items, including whether the disclosure item must be presented in tabular format. We discuss each below.

3. Item 1202 (Disclosure of Reserves)

Existing Instruction 3 to Item 102 of Regulation S–K requires disclosure of an extractive enterprise's proved reserves. With respect to oil and gas producing companies, we are replacing this Instruction by adding a new Item 1202 to Regulation S–K that contains a similar disclosure requirement regarding a company's proved reserves.[188] However, new Item 1202 expands on the requirements of Item 102 by specifically permitting the disclosure of probable and possible reserves and permitting the disclosure of reserves from non-traditional sources. In addition, because we are no longer distinguishing between types of accumulations, the item contains only one table with separate columns for different final products, specifically, oil, gas, synthetic oil, synthetic gas, and other natural resources sold by the company.

a. Oil and Gas Reserves Tables

New Item 1202 requires disclosure, in the aggregate and by geographic area, of reserves estimates using prices and costs under existing economic conditions, for each product type, in the following categories:

- Proved developed reserves;
- Proved undeveloped reserves;
- Total proved reserves;
- Probable developed reserves (optional);
- Probable undeveloped reserves (optional);
- Possible developed reserves (optional); and
- Possible undeveloped reserves (optional).

A form of this table is set forth below:

SUMMARY OF OIL AND GAS RESERVES AS OF FISCAL-YEAR END BASED ON AVERAGE FISCAL-YEAR PRICES

Reserves category	Reserves				
	Oil (mbbls)	Natural gas (mmcf)	Synthetic oil (mbbls)	Synthetic gas (mmcf)	Product A (measure)
PROVED					
Developed:					
Continent A	....	....	....	....	....

[180] See Item 1201(d) [17 CFR 229.1201(d)].

[181] See Item 1204(a) [17 CFR 229.1204(a)].

[182] See Item 1202(a)(2) [17 CFR 229.1202(a)(2)].

[183] See Instruction 4 to Item 1202(a)(2).

[184] See letters from Devon and Petrobras.

[185] See letter from Petro-Canada.

[186] See letters from Apache and ExxonMobil.

[187] See letters from Apache and ExxonMobil.

[188] See Item 1202 [17 CFR 229.1202].

SUMMARY OF OIL AND GAS RESERVES AS OF FISCAL-YEAR END BASED ON AVERAGE FISCAL-YEAR PRICES—Continued

Reserves category	Reserves				
	Oil (mbbls)	Natural gas (mmcf)	Synthetic oil (mbbls)	Synthetic gas (mmcf)	Product A (measure)
Continent B	....	....	....	....	....
Country A	....	....	....	....	....
Country B	....	....	....	....	....
Other Countries in Continent	....	....	....	....	....
Undeveloped:					
Continent A	....	....	....	....	....
Continent B	....	....	....	....	....
Country A	....	....	....	....	....
Country B	....	....	....	....	....
Other Countries in Continent B	....	....	....	....	....
TOTAL PROVED	....	....	....	....	....
PROBABLE					
Developed	....	....	....	....	....
Undeveloped	....	....	....	....	....
POSSIBLE					
Developed	....	....	....	....	....
Undeveloped	....	....	....	....	....

i. Disclosure by Final Product Sold

The table requires disclosure by final product sold by the company, specifically, oil, gas, synthetic oil, synthetic gas, or other natural resource. Thus, if the company processes a natural resource that it has extracted, such as bitumen, into synthetic oil or gas prior to selling the product, it may include such reserves under the synthetic oil or gas columns. As noted below, we have revised the proposal that would have required disclosure by type of accumulation. In addition, in response to commenters, we have revised the definition of ''oil and gas producing activities'' so that a company can use the price of that synthetic oil or gas to determine the economic producibility of the reserves because the economics of the processing activity are relevant to the determination of whether to extract the underlying resource.[189]

However, if a company extracts a resource other than oil or gas, such as bitumen, and sells the product without processing it into synthetic oil or gas, it must disclose reserves of that other natural resource. Although that company's extractive activities would be considered an oil and gas producing activity under the definition of that term, such a company would not benefit from the economics of processing of that resource because the price that determines whether such a company extracts the resource is the price of the unprocessed resource and therefore the company may not establish reserves estimates based on the price of the upgraded product. Similarly, if the company does not itself extract the natural resource, but purchases the natural resource for processing or is paid to process the natural resource, it may not claim reserves either of the resource or of the processed product.

ii. Aggregation

As proposed, the reserves to be reported in these tables would be aggregations (to the company total level) of reserves determined for individual wells, reservoirs, properties, fields, or projects. Regardless of whether the reserves were determined using deterministic or probabilistic methods, the reported reserves should be simple arithmetic sums of all estimates at the well, reservoir, property, field, or project level within each reserves category. Eight commenters agreed that aggregation should not be permitted beyond the field, property or project level, consistent with PRMS.[190]

iii. Optional Disclosure of Probable and Possible Reserves

A company may, but is not required to, disclose probable or possible reserves in these tables. If a company discloses probable or possible reserves, it must provide the same level of geographic detail as it must with respect to proved reserves and must state whether the reserves are developed or undeveloped. In addition, Item 1202 requires the company to disclose the relative uncertainty associated with these classifications of reserves estimations. By permitting disclosure of all three of these classifications of reserves, our objective is to enable companies to provide investors with more insight into the potential reserves base that managements of companies may use as their basis for decisions to invest in resource development.

Most commenters addressing this issue supported permitting the disclosure of probable and possible reserves in filed documents.[191] They believed that such disclosure would provide a more complete picture of a company's full portfolio of opportunities.[192] One commenter noted that this information often is already available on company Web sites and in press releases.[193] However, several commenters supporting the proposal cautioned that there could be significant variability among disclosures.[194]

Other commenters expressed concern about disclosure of unproved reserves, but conceded that voluntary disclosure would be acceptable.[195] These commenters were concerned that such disclosure may confuse investors and expose companies to increased litigation because of the inherent uncertainty associated with probable and possible reserves.[196] They noted that various

[189] See Section II.C.2 of this release.

[190] See letters from Devon, Evolution, ExxonMobil, Ryder Scott, Shell, SPE, Talisman, and Wagner.

[191] See letters from CFA, Chesapeake, Deloitte, EnCana, Evolution, McMoRan, Newfield, Petrobras, Petro-Canada, Questar, Ryder Scott, Sasol, Ryder Scott, Shell, SPE, Three Senators, Wagner, and Zakaib.

[192] See letters from CFA, Evolution, Petro-Canada, Ryder Scott, and Wagner.

[193] See letter from Evolution.

[194] See letter from EnCana.

[195] See letters from API, ExxonMobil, Imperial, Repsol, and Total.

[196] See letters from API, ExxonMobil, Imperial, and Repsol.

technologies may be used to support these estimates.[197]

Several commenters opposed permitting disclosure of probable and possible reserves in Commission filings for similar reasons.[198] Again, they were concerned that the inherent uncertainty associated with such reserves estimates may lead to investor confusion and misunderstanding.[199] They believed that the broad range of technologies and methods used by companies to support these estimates would lead to inconsistent disclosure among companies.[200]

We note that numerous oil and gas companies already disclose unproved reserves on their Web sites and in press releases. This practice does not appear to have created confusion in the market. However, we understand commenters' concerns that probable and possible reserves estimates are less certain than proved reserves estimates and so may increase litigation risk. By making these disclosures voluntary, a company could exercise its own discretion as to whether to provide the market with this disclosure.

Some commenters were concerned that voluntary disclosure by some companies may raise confusion as to why other companies do not disclose these classifications of reserves.[201] One commenter was concerned that voluntary disclosure may increase market pressure on all companies to disclose probable and possible reserves estimates.[202] Considering the fact that many companies already make these disclosures public, we do not believe that this is an adequate reason for prohibiting from filings disclosure that may be helpful to investors.

iv. Resources Not Considered Reserves

Because we are permitting disclosure of probable and possible reserves, we are revising existing Instruction 5 to Item 102 of Regulation S–K to continue to prohibit disclosure of estimates of oil or gas resources other than reserves, and any estimated values of such resources, in any document publicly filed with the Commission, unless such information is required to be disclosed in the document by foreign or state law.[203] Five commenters recommended that the rules permit disclosure of all categories of resources, including those that do not qualify as reserves.[204] One commenter believed that the prohibition against disclosing all resources deprives public markets of significant information without meaningfully enhancing investor protection and ultimately may harm the efficiency and development of U.S. markets and U.S. companies raising capital.[205] That commenter also thought such a restriction could also encourage companies to form outside of the U.S.[206] Another commenter believed that the uncertainty of resource estimates is best communicated by reporting the full range of estimates.[207] In addition, another commenter believed that clear disclosure would allay concerns about investor misunderstanding of estimates of resources that do not qualify as reserves.[208] That commenter noted that excluding resources that are not reserves is inconsistent with international standards and the fact that these resources are disclosed in the U.S. on Web sites and in press releases.[209] We continue to be concerned that such resources are too speculative and may lead investors to incorrect conclusions. Therefore, we are adopting the proposal to prohibit disclosure of resources other than reserves.

However, consistent with existing Instruction 5, a company may continue to disclose such estimates of non-reserves resources in a Commission filing related to an acquisition, merger, or consolidation if the company previously provided those estimates to a person that is offering to acquire, merge, or consolidate with the company or otherwise to acquire the company's securities.[210] Several commenters recommended that the Commission maintain this exception so that the company's shareholders would not be at an informational disadvantage compared to the counterparty when assessing a merger.[211] We agree with these commenters and have retained the exception in the revised Instruction 5 adopted today.

b. Optional Reserves Sensitivity Analysis Table

The rules that we are adopting require a company to determine whether its oil or gas resources are economically producible based on a 12-month average price. We also proposed, and are adopting, an optional reserves sensitivity table. This table would permit companies to disclose additional information to investors, such as the sensitivity that oil and gas reserves have to price fluctuations. If a company chooses to provide such disclosure, it may choose the different scenario or scenarios, if any, that it wishes to disclose in the table, provided that it also discloses the price and cost schedules and assumptions on which the alternate reserves estimates are based.

Twelve commenters supported permitting such sensitivity analyses.[212] Some believed that this would provide investors with a better view of management's analysis of future prices.[213] One recommended providing a set price change of 10% for the sensitivity analysis.[214] Two other commenters believed that different circumstances may require different types of sensitivity analyses, both with respect to the range of prices used and the format of the presentation.[215] We agree that the appropriate range for a sensitivity analysis may vary depending on the situation, and therefore, as proposed, we are not specifying a range of prices to be used.

However, five commenters specifically opposed requiring such an analysis.[216] They believed that such a requirement would cause confusion and harm comparability.[217] Three commenters opposed such a sensitivity analysis because using different prices could mislead investors.[218] We are adopting this table, as proposed, as a voluntary disclosure rather than a requirement. However, as proposed, the table would require disclosure of the assumptions behind varying estimates. We believe this disclosure will mitigate any investor confusion.

In addition, we remind companies that Item 303 of Regulation S–K (Management's Discussion and Analysis of Financial Condition and Results of Operations)[219] requires discussion of

[197] See letters from API, ExxonMobil, and Imperial.

[198] See letters from Apache, Devon, Energen, Eni, and Southwestern.

[199] See letters from Apache, Devon, Eni, and Southwestern.

[200] See letters from Devon, Eni, and Southwestern.

[201] See letters from Apache and Total.

[202] See letter from Eni.

[203] See Instruction 5 to Item 102 [17 CFR 229.102].

[204] See letters from Davis Polk, Petro-Canada, Shearman & Sterling, SPE, and Zakaib.

[205] See letter from Shearman & Sterling.

[206] *Id.*

[207] See letter from SPE.

[208] See letter from Davis Polk.

[209] See letter from Davis Polk.

[210] *Id.*

[211] See letters from Devon, ExxonMobil, Shell, and Total.

[212] See letters from Canadian Natural, CAPP, CFA, Chesapeake, Deloitte, Devon, Evolution, ExxonMobil, McMoRan, Nexen, Petro-Canada, and Total.

[213] See letters from Chesapeake, Deloitte, and McMoRan.

[214] See letter from CFA.

[215] See letters from Evolution and Total.

[216] See letters from Canadian Natural, CAPP, Devon, EnCana, and ExxonMobil.

[217] See letters from EnCana and Ryder Scott.

[218] See letters from Apache, Petrobras, and Wagner.

[219] See Item 303 of Regulation S–K [17 CFR 229.303].

known trends and uncertainties, which may include changes to prices and costs. A form of this optional reserves sensitivity analysis table is set forth below.

SENSITIVITY OF RESERVES TO PRICES BY PRINCIPAL PRODUCT TYPE AND PRICE SCENARIO

Price case	Proved reserves			Probable reserves			Possible reserves		
	Oil Mbbls	Gas mmcf	Product A measure	Oil mbbls	Gas mmcf	Product A measure	Oil mbbls	Gas mmcf	Product A measure
Scenario 1	....	....	....	....	....	....	....	....	....
Scenario 2	....	....	....	....	....	....	....	....	....

c. Separate Disclosure of Conventional and Continuous Accumulations

Under the proposal, new Item 1202 would have required companies to disclose reserves from conventional accumulations separately from reserves in continuous accumulations. Nine commenters recommended disclosure based on the final product.[220] These commenters opposed segregating disclosure based on the type of accumulation that is involved.[221] They believed that such disclosure would be too complex and detailed and of little use to investors.[222] In addition, seven commenters pointed out that separation may be impossible because some fields contain both conventional and continuous accumulations.[223] This would make allocation of costs arbitrary.[224] However, four commenters supported the definitions and separate disclosure by type of accumulation.[225] One commenter believed that such disclosure would allow investors to assess the impact of unconventional sources on reserves.[226]

Although we agree conceptually that the focus of reserves disclosure should be on the final product, we also recognize that the production of oil and gas from varying sources can have significantly different economics. Extraction of oil and gas from continuous accumulations can be much more labor and resource intensive than extraction of oil and gas from traditional wells. They often require greater ongoing efforts and expense after the initial extraction equipment is in place, making such operations more sensitive to price fluctuations.

We agree with the commenters that disclosure based on the end product sold would provide a more effective basis for distinguishing reserves that disclosure based on the type of accumulation in which the reserves are held. Therefore, we have revised the disclosure to be based on the end product that is sold by the company.[227] However, with respect to the end product, new Item 1202 makes a distinction between oil and gas, on the one hand, and synthetic oil and gas, on the other. Synthetic products require processing of the raw resource material, either while it is still in the ground (''in situ'') or after it is extracted, before it can be used as refinery feedstock or as natural gas. Such processes currently include bitumen upgrading as well as coal liquefaction and gasification. However, resources from some continuous accumulations, such as coalbed methane, do not require such processing and therefore are not associated with the same level of ongoing costs once a well has been drilled because the in-ground resource is already oil or gas (in the case of coalbed methane, the in-ground resource is methane, trapped in a coalbed). Thus, coalbed methane would not be considered a synthetic product.

d. Preparation of Reserves Estimates or Reserves Audits

In the Proposing Release, we proposed to require a company to disclose whether or not the technical person[228] primarily responsible for preparing the reserves estimate possessed certain specified qualifications and was subject to a list of controls for maintaining objectivity. Most commenters addressing the issue opposed this proposed requirement.[229] However, many of these commenters appeared to believe that the disclosure requirement would pertain to every person involved with the estimation process.[230] If adopted, they noted that such disclosure would be voluminous, adding unnecessary complexity to disclosures.[231] Four commenters suggested that we clarify that the disclosure is limited to the chief technical person who oversees the company's overall reserves estimation process,[232] which was the intent of the proposal. Five commenters supported this disclosure because it helps users understand the objectivity and quality of reserves estimates.[233]

It was our intent to limit the disclosure to the technical person primarily responsible for overseeing the reserves estimates. However, there may have been confusion with respect to this point based on a footnote which stated that we sought disclosure about the person who ''is primarily responsible for the actual calculations and estimation or audit.'' By that term, we did not intend to include *any* person making ''actual calculations.'' We recognize that, ultimately, the reserves estimates are overseen by top management, which may or may not have reserves estimation expertise. The focus of the final rule is the primary technical person responsible for overseeing the preparation of the reserves estimation process. We have

[220] See letters from Apache, API, Canadian Natural, CAPP, EnCana, ExxonMobil, Imperial, Petro-Canada, and Total.

[221] See letters from Apache, API, CAPP, Chesapeake, Devon, ExxonMobil, Imperial, Repsol, and Shell.

[222] See letters from Apache, API, BP, CAPP, Chesapeake, Chevron, Devon, E&Y, EnCana, ExxonMobil, Imperial, Petro-Canada, Repsol, and Southwestern.

[223] See letters from BP, Canadian Natural, CAPP, EnCana, Petro-Canada, Ryder Scott, and Talisman.

[224] See letters from EnCana and Ryder Scott.

[225] See letters from Davis Polk, EIA, Petrobras, and Wagner.

[226] See letter from Wagner.

[227] See Item 1202 [17 CFR 229.1202].

[228] With regard to the objectivity of a technical person, the ''person'' could be an individual or an entity, as appropriate. However, with regard to the qualifications of a person, the disclosure would relate to the individual who is primarily responsible for the technical aspects of the reserves estimation or audit. Thus, this individual is not necessarily the individual generally overseeing the estimation or audit, but the individual who is primarily responsible for the actual calculations and estimation or audit.

[229] See letters from Apache, API, Chevron, Energen, Eni, ExxonMobil, Newfield, Nexen, PEMEX, Petro-Canada, Ryder Scott, Shell, and Total.

[230] See letters from Apache, API, ExxonMobil, Newfield, Nexen, PEMEX, Ryder Scott, and Total.

[231] See letters from Apache, API, ExxonMobil, Newfield, Nexen, PEMEX, Repsol, and Total.

[232] See letters from API, ExxonMobil, PEMEX, and Petro-Canada.

[233] See letters from CFA, Devon, EnCana, Southwestern, and Wagner.

revised the language in the rule to clarify this point.[234]

Two commenters noted that it was inconsistent to require such precise disclosure about reserves experts, but not other experts.[235] One of those commenters recommended that the rule require expert language, including clear disclosure of which portion of the reserves estimate the third party is expertising and filed consents.[236] The concept of an expert under the Securities Act is different from the disclosures that we seek regarding the qualifications and objectivity of persons responsible for the preparation or audit of oil and gas reserves. Under the Securities Act, disclosure must be made when the company represents that disclosure is based on the authority of an expert. Although the Securities Act concept of experts will continue to be relevant when the reserves disclosures are in, or incorporated into, a Securities Act filing and the company represents that disclosure is based on the authority of an expert, the new rules requiring disclosure about the reserves preparer or auditor in a company's Exchange Act reports are intended to help investors determine whether reserves estimates, which are highly technical, have been prepared by a qualified, objective person, regardless of whether that person is an employee of the company.

However, we agree with commenters that a prescribed list of qualifications and objectivity requirements may be too rigid for all situations. With respect to technical qualifications, several commenters noted that licensing requirements can vary greatly among jurisdictions.[237] Commenters also believed that disclosure of a person's objectivity was unnecessary because management is required to install appropriate internal controls to ensure the reliability of reserves estimates.[238] In fact, some commenters recommended that we limit the disclosure to a description of a company's internal controls, including the company's technical assessment routine, management and board review and approval processes, the internal audit process, the extent to which the company uses external parties to estimate or audit reserves estimates, and a summary description of the qualifications of the company's typical reserves estimators.[239] We are following these commenters' recommendations and adopting a rule that requires a company to provide a general discussion of the internal controls that it uses to assure objectivity in the reserves estimation process and disclosure of the qualifications of the technical person primarily responsible for preparing the reserves estimates or conducting the reserves audit if the company discloses that such a reserves audit has been performed, regardless of whether the technical person is an employee or an outside third party.[240]

We did not propose, but sought comment on, whether the rules should require a company to retain an independent third party to prepare, or conduct a reserves audit of, the company's reserves estimates. Most commenters urged the Commission not to adopt such a requirement.[241] They believed that a company's internal staff, particularly at larger companies, is generally in a better position to prepare those estimates[242] and that there is a potential lack of qualified third party engineers and other professionals available to conduct the increased work that would result from such a requirement.[243] We agree with these commenters and are not adopting a requirement that an independent third party prepare, or conduct a reserves audit of, the company's reserves estimates.

e. Reserve Audits and The Contents of Third-Party Reports

In the Proposing Release, we proposed that, if a company represents that its estimates of reserves are prepared or audited by a third party, the company must file a report of the third party as an exhibit to the relevant registration statement or report. Two commenters believed that a company description of the third party's report would be sufficient because the reports can contain sensitive information.[244] However, another commenter was concerned that not filing the report may lead to mischaracterizations by the company.[245] This commenter supported the filing of a report by the third party reserves estimator or auditor, but believed that the Commission should determine the contents of such a report.[246] Two commenters supported the filing of the report ''letter'' as an exhibit, but not the full reserves report because it may contain proprietary information.[247]

As proposed, we are adopting a new rule to require that if the company represents that a third party prepared the reserves estimate or conducted a reserves audit of the reserves estimates, the company must file a report of the third party as an exhibit to the relevant registration statement or report.[248] These reports need not be the full ''reserves report,'' which is often very detailed and voluminous. Rather, these reports could be shorter form reports that summarize the scope of work performed by, and conclusions of, the third party. These reports must include the following disclosure, based on the Society of Petroleum Evaluation Engineers's audit report guidelines:

- The purpose for which the report is being prepared and for whom it is prepared;
- The effective date of the report and the date on which the report was completed;
- The proportion of the company's total reserves covered by the report and the geographic area in which the covered reserves are located;
- The assumptions, data, methods, and procedures used to conduct the reserves audit, including the percentage of company's total reserves reviewed in connection with the preparation of the report, and a statement that such assumptions, data, methods, and procedures are appropriate for the purpose served by the report;
- A discussion of primary economic assumptions;
- A discussion of the possible effects of regulation on the ability of the registrant to recover the estimated reserves;
- A discussion regarding the inherent risks and uncertainties of reserves estimates;
- A statement that the third party has used all methods and procedures as it considered necessary under the circumstances to prepare the report; and
- The signature of the third party.

In addition, if the report is related to a reserves audit, it must contain a brief summary of the third party's conclusions with respect to the reserves estimates. Finally, if the disclosures are

[234] See Item 1202(a)(7) [17 CFR 229.1202(a)(7)].

[235] See letters from API and Deloitte.

[236] See letter from Deloitte.

[237] See letters from AAPG, API, Chevron, Eni, Petro-Canada, Questar, and SPE.

[238] See letters from API, Chevron, Energen, ExxonMobil, Newfield, Nexen, Petrobras, Ryder Scott, Shell, StatoilHydro, and Total.

[239] See letters from ExxonMobil, Nexen, Shell, and StatoilHydro.

[240] See Item 1202(a)(7) [17 CFR 229.1202(a)(7)].

[241] See letters from API, BHP, BP, CFA, CNOOC, Denbury, Devon, Eni, Energy Literacy, ExxonMobil, Imperial, R. Jones, D. McBride, Newfield, Nexen, Petro-Canada, Ross, D. Ryder, Sasol, Shell, Talisman, Total, and W. van de Vijver.

[242] See letters from API, Denbury, ExxonMobil, Imperial, Nexen, Shell, and Talisman.

[243] See letters from AAPG, API, BP, Devon, ExxonMobil, Imperial, D. McBride, Newfield, D. Ryder, and Sasol.

[244] See letters from Evolution and Petro-Canada.

[245] See letter from Wagner.

[246] See letter from Wagner.

[247] See letters from Devon and Ryder Scott.

[248] See Item 1202(a)(8) [17 CFR 229.1202(a)(8)].

made in, or incorporated into, a Securities Act registration statement, the company must file a consent of the third party as an exhibit to the filing.

In the Proposing Release, we proposed to define the term ''reserves audit'' as ''the process of reviewing certain of the pertinent facts interpreted and assumptions made that have resulted in an estimate of reserves prepared by others and the rendering of an opinion about the appropriateness of the methodologies employed, the adequacy and quality of the data relied upon, the depth and thoroughness of the reserves estimation process, the classification of reserves appropriate to the relevant definitions used, and the reasonableness of the estimated reserves quantities. In order to disclose that a 'reserves audit' has been conducted, the report resulting from this review must represent an examination of at least 80% of the portion of the registrant's reserves covered by the reserves audit.'' We are substantively adopting the first sentence of this definition as proposed.

However, in response to comments received, we are not adopting the proposed second sentence of the definition of the term ''reserves audit.'' Two commenters supported the proposed 80% threshold regarding the proportion of reserves that a reserves auditor must review in order for the company to characterize that auditor's work as a ''reserves audit.'' [249] Another commenter believed that the 80% threshold was appropriate for preparing reserves estimates.[250] But three commenters believed that an audit should simply disclose the percentage that was audited.[251] One of these noted that it has its reserves audit performed on a rolling basis.[252] We believe that disclosure of the work done in the required third-party report makes a bright-line percentage test unnecessary. If a company conducts its reserves audit on a rolling basis, it is appropriate for its shareholders to be aware of that fact. Therefore, we are not adopting the proposed 80% threshold. We believe that disclosure of the scope of the review will enable investors to assess the significance to attribute to a reserves audit.

f. Process Reviews

In the Proposing Release, we solicited comment regarding whether we should permit a company to disclose that it has hired a third party to perform a process review under the Society of Petroleum Engineers' (SPE's) reserves auditing standards.[253] Those standards define a process review as an investigation by a person who is qualified by experience and training equivalent to that of a reserves auditor to address the adequacy and effectiveness of an entity's internal processes and controls relative to reserves estimation. However, those standards also note that a process review should not include an opinion relative to the reasonableness of the reserves quantities and should be limited to the processes and control system reviewed. The SPE's standards state that, although such reviews may provide value to the entity, an external or internal process review is not of sufficient rigor to establish appropriate classifications and quantities of reserves and should not be represented to the public as being equivalent to a reserves audit.

Five commenters believed that internal process reviews are helpful in promoting accuracy and effectiveness, so companies should be permitted to disclose them.[254] However, one commenter was concerned that, although a process review can be helpful for a company, disclosure may give investors a false sense of security.[255] Two commenters suggested that, if a company discloses that it performed a process review, it should clearly disclose what a process review is.[256]

We agree that a process review can be helpful to the company and ultimately to investors. However, we also agree that if a company discloses that it has hired a third party to perform a process review, it must clearly disclose the details surrounding that process review. As such, the new rules treat a process review similar to a reserves audit. If the company discloses that it has hired a third party to conduct a process review, it must file a report of the third party as an exhibit to the relevant registration statement or report and, if the disclosures are made in, or incorporated into, a Securities Act registration statement, the company must file a consent of the third party as an exhibit to the filing.[257]

4. Item 1203 (Proved Undeveloped Reserves)

We proposed requiring tabular disclosure of the aging of proved undeveloped reserves (PUDs). Proposed Item 1203 would have required an oil and gas company to prepare a table showing, for each of the last five fiscal years and by product type, proved reserves estimated using current prices and costs in the following categories:

- Proved undeveloped reserves converted to proved developed reserves during the year; and
- Net investment required to convert proved undeveloped reserves to proved developed reserves during the year.[258]

Numerous commenters were concerned that the proposed five-year table would be too complex for investors to understand.[259] They expressed concern that the proposed table may mislead investors by not clearly attributing costs to the year in which the corresponding PUDs are converted because much of the costs may have been spent in previous years.[260] In addition, commenters noted that maintenance of such data would be costly [261] and that companies currently do not always capture this type of information because management does not use it to run the business.[262]

Eight commenters suggested an alternative of disclosing (1) the quantity of undeveloped reserves if material, (2) the progress in converting PUDs, and (3) any material changes in the current year.[263] Three U.S. Senators recommended requiring disclosure of development plans in addition to the table.[264] They believed that requiring reporting of investments and planned investments in oil and gas development would provide investors with certainty about companies' intentions to develop the federal lands that they have at their disposal.[265] However, three commenters opposed disclosure of a company's plans to drill and expected capital expenditures because disclosing their business plan may cause competitive harm and might expose them to litigation if results differ from their plan.[266] Six commenters supported the proposed table.[267]

[249] See letters from Evolution and Wagner.

[250] See letter from Ryder Scott.

[251] See letters from Devon, Ryder Scott, and Talisman.

[252] See letter from Talisman.

[253] See SPE Reserves Auditing Standards.

[254] See letters from Devon, ExxonMobil, Petro-Canada, Ryder Scott, and Shell.

[255] See letter from Wagner.

[256] See letters from Devon and Petro-Canada.

[257] See Item 1202(a)(8) [17 CFR 229.1202(a)(8)].

[258] See Item 1204 [17 CFR 229.1204].

[259] See letters from API, BP, Canadian Natural, CAPP, Chevron, Eni, Equitable, ExxonMobil, Nexen, Petrobras, Repsol, Shell, and Wagner.

[260] See letters from API, ExxonMobil, Petrobras, Ryder Scott, Total, and Wagner.

[261] See letters from API, Canadian Natural, CAPP, Chevron, Eni, Equitable, ExxonMobil, Nexen, Petrobras, Southwestern, and Wagner.

[262] See letter from Apache.

[263] See letters from API, Canadian Natural, Chevron, ExxonMobil, Newfield, Nexen, Petrobras, and Ryder Scott.

[264] See letter from Three Senators.

[265] See letter from Three Senators.

[266] See letters from Chesapeake, Devon, and Newfield.

[267] See letters from Chesapeake, Deloitte, Devon, Three Senators, Talisman, and Wagner.

We recognize the concern that the PUD table that we proposed may be confusing to investors because it would not attribute capital expenditures to the corresponding reserves as they are developed. As an alternative to the proposed table, we are adopting rules that require a company to disclose the following in narrative form:

- The total quantity of PUDs at year end;
- Any material changes in PUDs that occurred during the year, including PUDs converted into proved developed reserves;
- Investments and progress made during the year to convert PUDs to proved developed oil and gas reserves; and
- An explanation of the reasons why material concentrations of PUDs in individual fields or countries have remained undeveloped for five years or more after disclosure as PUDs.[268]

These disclosures would have been required under the proposal, but much of it would have been presented in tabular format. We believe that a narrative approach to these disclosures will provide companies with a better vehicle to explain the status of their PUDs and their track record for developing such reserves. Rather than requiring forward-looking information about a company's plans to develop reserves that may lead to exaggeration of a company's capability to actually convert such reserves, we believe that disclosure of a company's verifiable, established track record of converting such reserves, including its ability to obtain financing for such activities, would be a better indication of the likelihood of that company's success in developing reserves in the future. Specific required disclosure regarding a company's failure to develop material concentrations of PUDs for five or more years should address commenters' concerns that the company may have no intention to develop such reserves.

5. Item 1204 (Oil and Gas Production)

We proposed to codify the Industry Guide 2 disclosure regarding oil and gas production as Item 1204 of Regulation S–K, in tabular form and with greater detail. One commenter did not believe that separating production, sales price and production costs based on whether they were related oil wells or gas wells would be valuable to investors.[269] It believed that companies do not use this information to manage their business and do not maintain systems to capture this information on that basis, so tracking such data would require costly changes to their systems.[270] Two commenters also believed that it would not be possible to separate production cost by product because many units extract different products.[271] One commenter also recommended that production not be segregated by type of accumulation.[272]

We have decided not to adopt Item 1204 as proposed. Rather, we are codifying the existing Industry Guide 2 disclosure item with several revisions. Consistent with the Industry Guide 2 disclosure item, the Item 1204, as adopted, requires disclosure, for each of the prior three fiscal years, of production, by final product sold, of oil, gas, and other products. In addition, for the same time period, the company must disclose, by geographical area:

- The average sales price (including transfers) per unit of oil, gas and other products produced; and
- The average production cost, not including ad valorem and severance taxes, per unit of production.

However, unlike the Industry Guide disclosure item, this disclosure must be made by geographical area and for each country and field containing 15% or more of the registrant's proved reserves, expressed on an oil-equivalent-barrels basis.

Similarly, we are codifying the instructions to the Industry Guide 2 item. One commenter recommended that we maintain some of the existing instructions from the Industry Guide.[273] The first instruction codified from the Industry Guide clarifies that net production should include only production that is owned by the registrant and produced to its interest, less royalties and production due others. However, in special situations (*e.g.*, foreign production), net production before any royalties may be provided, if more appropriate. If ''net before royalty'' production figures are furnished, the change from the usage of ''net production'' should be noted.

The second instruction, which is also from the Industry Guide, states that production of natural gas should include only marketable production of natural gas on an ''as sold'' basis. Production will include dry, residue, and wet gas, depending on whether liquids have been extracted before the registrant transfers title. Flared gas, injected gas, and gas consumed in operations should be omitted. Recovered gas-lift gas and reproduced gas should not be included until sold. Synthetic gas, when marketed as such, should be included in natural gas sales.

We are adding a third instruction that was not in the Industry Guide. This instruction states that, if any product, such as bitumen, is sold or custody is transferred prior to conversion to synthetic oil or gas, the product's production, transfer prices, and production costs should be disclosed separately from all other products. This instruction is necessary because the existing Industry Guide 2 disclosure requirement only required separate disclosure based on whether the end product was oil or gas. This instruction merely clarifies that disclosures under this item must be based on the end product, which may not be oil or gas because the amendments will permit the disclosure of reserves of other end products, such as bitumen.

The fourth instruction codified from the Industry Guide states that the transfer price of oil and gas (natural and synthetic) produced should be determined in accordance with SFAS 69. And the fifth instruction codified from the Industry Guide clarifies that the average production cost per unit of production should be computed using production costs disclosed pursuant to SFAS 69. Units of production should be expressed in common units of production with oil, gas, and other products converted to a common unit of measure on the basis used in computing amortization. This instruction also adds products from unconventional sources to the existing disclosure Item in Industry Guide 2.

6. Item 1205 (Drilling and Other Exploratory and Development Activities)

We proposed to codify the Industry Guide 2 disclosure item regarding drilling activities as Item 1205 of Regulation S–K, in tabular form, with several revisions to that Industry Guide 2 disclosure item, including applying a new definition of the term ''geographic area'' and adding two categories of wells:

- Extension wells; and
- Suspended wells.

Three commenters believed that the disclosures required under this proposed Item would become too detailed.[274] One of these commenters also believed that the number of wells being drilled does not provide an accurate picture of a company's drilling

[268] See Item 1203 [17 CFR 229.1203].

[269] See letter from Apache.

[270] See letter from Apache.

[271] See letters from Total and ExxonMobil.

[272] See letter from ExxonMobil.

[273] See letter from ExxonMobil.

[274] See letters from Apache, ExxonMobil, and Total.

activities because of the increased usage of horizontal wells.[275]

Some commenters also did not believe that creating new categories for extension wells and suspended wells would be meaningful.[276] They noted the burden of the added detail would exceed the value of the information to investors.[277] One pointed out that determining whether a well constitutes an extension well would be difficult because of multipurpose drilling.[278]

After considering the above comments, we have decided not to adopt all of the proposed revisions to the existing Industry Guide 2 disclosure. We recognize that, for some companies that use advanced drilling techniques, the proposed disclosure may not be a good indicator of the extent of their exploratory and development activities, although we believe that this disclosure is still important for many companies. Therefore, we have decided to codify the existing disclosures found in Industry Guide 2 related to drilling activities without revision and to not require tabular disclosure.[279] However, as proposed, we are adding a new provision to this Item that requires companies to discuss their exploratory and development activities regarding oil and gas resources that are extracted by mining techniques because we are now including such resources under the definition of ''oil and gas producing activities.''

7. Item 1206 (Present Activities)

Item 1206 codifies existing Item 7 of Industry Guide 2, which calls for disclosure of present activities, including the number of wells in the process of being drilled (including wells temporarily suspended), waterfloods in process of being installed, pressure maintenance operations, and any other related activities of material importance.[280] We are adopting Item 1206 substantially as proposed.

8. Item 1207 (Delivery Commitments)

Item 1207 codifies existing Item 8 of Industry Guide 2, which calls for disclosure of arrangements under which the company is required to deliver specified amounts of oil or gas and how the company intends to meet such commitments.[281] We are not adopting any substantive changes to the disclosure currently called for by Item 8 of Industry Guide 2. However, we are restructuring and rewording the disclosure item to make it easier to understand, including separating embedded lists into separate subparagraphs and making general plain English revisions. As proposed, these revisions are not intended to change the substance of the disclosures.

9. Item 1208 (Oil and Gas Properties, Wells, Operations, and Acreage)

We proposed to codify disclosure about oil and gas properties, wells, operations, and acreage as Item 1208 of Regulation S–K, in tabular form, as well as make several revisions to the existing disclosures, including applying a new definition of the term ''geographic area'' and adding language that better illustrates the types of properties and the types of disclosures for those properties, including the following:

- Identification and description generally of the company's material properties, plants, facilities, and installations;
- Identification of the geographic area in which they are located;
- Indication of whether they are located onshore or offshore; and
- Description of any statutory or other mandatory relinquishments, surrenders, back-ins, or changes in ownership.

Six commenters believed that it is not necessary to enhance this section from Industry Guide 2 because the requirements are already covered by Item 102 of Regulation S–K.[282] Commenters were particularly concerned with the segmentation of this disclosure by product, by type of accumulation, and by geographic location.[283] They believed that this level of detail would not be helpful to investors and would impose added costs on companies because they currently do not collect this detailed information.[284] Moreover, seven commenters thought that the well count disclosure is no longer meaningful because of technologies such as horizontal drilling.[285] They thought that, in light of these new technologies, well count disclosure could be misleading.[286]

As with the case of drilling activities, we agree that the proposed added detail could make the disclosures too cumbersome. In addition, such disclosure may be of less importance to many companies because of new drilling technology. Therefore, we are merely codifying the existing Industry Guide 2 disclosure, without revision.[287]

V. Guidance for Management's Discussion and Analysis for Companies Engaged in Oil and Gas Producing Activities

We proposed to add a new Item 1209, which would have specified topics that a company should address either as part of its Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) or in a separate section.[288] Four commenters were concerned that, although the proposed Item was intended to provide more guidance regarding the disclosures required, it would effectively require companies to address all of the issues listed in the Item.[289] One recommended that, instead of a detailed list, the requirement should clarify that companies should address ''material changes due to technology, prices, concession conditions, commercial terms, known trends, demands, commitments, uncertainties and any events that are reasonably likely to have a material effect on reserves estimates and financial condition.'' [290] Similarly, another commenter recommended that the Commission clarify that the Item is limited to material impacts.[291]

We are not adopting the proposed Item as part of Regulation S–K because it is intended to be guidance, rather than a specific disclosure Item. We agree that, if companies were to discuss every issue provided in the list, the disclosure would be too long and detailed to be of much use to most investors. Important issues could be hidden amid unnecessary detail. However, we believe that added guidance would be beneficial to companies regarding the issues that the Commission's staff commented upon in its review of the MD&A section of filings made by oil and gas companies.

To begin, a fundamental premise of MD&A is that the information provided should be related to issues that are material to a company. Although we discuss a list of topics that a company might need to discuss, a company need only discuss a topic if it constitutes, involves, or indicates known trends, demands, commitments, uncertainties, and events that are reasonably likely to have a material effect on the company. These topics include:

[275] See letter from ExxonMobil.
[276] See letters from Apache, API, and Imperial.
[277] See letters from Apache and Southwestern.
[278] See letter from Total.
[279] See Item 1205 [17 CFR 229.1205].
[280] See Item 1206 [17 CFR 229.1206].
[281] See Item 1207 [17 CFR 229.1207].
[282] See letters from API, Chevron, ExxonMobil, Imperial, Shell, and Total.
[283] See letters from Apache, ExxonMobil, Shell, and Total.
[284] See letters from Apache, ExxonMobil, and Petro-Canada.
[285] See letters from API, BP, Chevron, ExxonMobil, Imperial, StatoilHydro, and Total.
[286] See letters from API and Imperial.
[287] See Item 1208 [17 CFR 229.1208].
[288] See Item 303 of Regulation S–K [17 CFR 229.303].
[289] See letters from Chevron, ExxonMobil, Petrobras, and Shell.
[290] See letter from Repsol.
[291] See letter from Total.

• Changes in proved reserves and, if disclosed, probable and possible reserves, and the sources to which such changes are attributable, including changes made due to:
  ○ Changes in prices;
  ○ Technical revisions; and
  ○ Changes in the status of any concessions held (such as terminations, renewals, or changes in provisions);
• Technologies used to establish the appropriate level of certainty for any material additions to, or increases in, reserves estimates, including any material additions or increases to reserves estimates that are the result of any of the final rules adopted in this release;
• Prices and costs, including the impact on depreciation, depletion and amortization as well as the full cost ceiling test;
• Performance of currently producing wells, including water production from such wells and the need to use enhanced recovery techniques to maintain production from such wells;
• Performance of any mining-type activities for the production of hydrocarbons;
• The company's recent ability to convert proved undeveloped reserves to proved developed reserves, and, if disclosed, probable reserves to proved reserves and possible reserves to probable or proved reserves;
• The minimum remaining terms of leases and concessions;
• Material changes to any line item in the tables described in Items 1202 through 1208 of Regulation S–K;
• Potential effects of different forms of rights to resources, such as production sharing contracts, on operations; and
• Geopolitical risks that apply to material concentrations of reserves.

The MD&A is typically presented in a self-contained section of the registration statement or report. However, the disclosure requirements that comprise new Subpart 1200 of Regulation S–K will cause a substantial amount of an oil and gas company's disclosure to appear in tabular format, providing an outline of much of a company's operations. Because the tables will present many of the types of changes that management often discusses in its MD&A, we believe it may be more helpful to investors to locate such discussion close to the tables themselves. Thus, to the extent that any discussion or analysis of known trends, demands, commitments, uncertainties, and events that are reasonably likely to have a material effect on the company is directly relevant to a particular disclosure required by Subpart 1200, the company may include that discussion or analysis with the relevant table, with appropriate cross-references, rather than including it in its general MD&A section.

VI. Conforming Changes to Form 20–F

Form 20–F is the form on which foreign private issuers file their annual reports and Exchange Act registration statements. Currently, Form 20–F contains instructions that are similar to those in Item 102 of Regulation S–K. However, rather than referring to Industry Guide 2 for disclosures regarding oil and gas producing activities, Form 20–F contains its own ''Appendix A to Item 4.D—Oil and Gas'' (Appendix A) that provides guidance for oil and gas disclosures for foreign private issuers.[292] Appendix A is significantly shorter, and provides far less guidance regarding disclosures, than Subpart 1200 or Industry Guide 2. We proposed to revise Form 20–F to eliminate the reference to Appendix A, and rather refer to Subpart 1200, which would expand the disclosures required by foreign private issuers.

Six commenters supported harmonizing the Form 20–F disclosures with Regulation S–K.[293] One noted that the proposal would make disclosure more consistent and comparable among oil companies.[294] It believed the proposal would put all oil companies on a level playing field.[295] However, one commenter recommended that the Commission exempt companies reporting under International Financial Reporting Standards (IFRS).[296] It also recommended that instead of applying the proposed Subpart 1200 to foreign private issuers, the Commission should revise Appendix A to Form 20–F itself, making appropriate limitations for foreign private issuers, such as eliminating the disclosure of wells and acreage.[297] Another commenter was concerned because the proposals may hinder, rather than facilitate, transition to the use of IFRS.[298]

We continue to believe that Subpart 1200 would be appropriate disclosure for all public companies engaged in oil and gas producing activities, including foreign private issuers. The added guidance in Subpart 1200 should promote more consistent and comparable disclosures among oil and gas companies. It is our understanding that many of the larger foreign private issuers already provide disclosure in their filings with the Commission comparable to the disclosure provided by domestic companies. Thus, we are revising Form 20–F to incorporate Subpart 1200 with respect to oil and gas disclosures and delete Appendix A to Item 4.D in that form. We recognize that this requirement may require a foreign private issuer to prepare two different reserves estimates if the rules in their home jurisdiction require a different pricing standard than the 12-month average that we adopt in this release. However, we believe the same conflict would have existed under our previous rule to the extent our pricing method differed from the home jurisdiction's method.

Appendix A currently allows a foreign private issuer to exclude required disclosures about reserves and agreements if its home country prohibits the disclosures. Two commenters suggested that the rule continue to provide an exception for disclosures about reserves and agreements that are prohibited by foreign laws.[299] However, another commenter believed that a company taking advantage of such an exception should be required to disclose the country, the citation of the relevant law or regulation, and the fact that the disclosed estimates do not include amounts from the named country.[300] We are not revising this provision. Rather, because these considerations still apply to such foreign private issuers, we are moving that provision from Appendix A and adopting it as Instruction 2 to Item 4 of Form 20–F, as proposed.[301]

One commenter recommended clarifying that the new disclosures would not apply to foreign private issuers under the Multi-Jurisdictional Disclosure System (MJDS) using Form 40—F that comply with NI 51–101 in Canada because those rules already are broadly consistent with PRMS.[302] We agree with this commenter and believe that such issuers need not provide disclosures beyond those required in Canada.

VII. Impact of Amendments on Accounting Literature

A. Consistency With FASB and IASB Rules

Numerous commenters recommended that the SEC generally coordinate its efforts with the IASB and FASB to create a cohesive whole and not adopt

[292] See Appendix A to Item 4.D—Oil and Gas of Form 20–F [17 CFR 249.220f].

[293] See letters from CAQ, Deloitte, ExxonMobil, KPMG, PWC, and Shell.

[294] See letter from ExxonMobil.

[295] See letter from ExxonMobil.

[296] See letter from Total.

[297] See letter from Total.

[298] See letter from Ross.

[299] See letters from Shell and Total.

[300] See letter from ExxonMobil.

[301] *Id.*

[302] See letter from Deloitte.

competing models.[303] We have begun, and will continue, to work with both of these organizations to ensure a smooth transition to the new reporting rules.

B. Change in Accounting Principle or Estimate

In the Proposing Release, we expressed our view that the change from using single-day year-end price to an average price should be treated as a change in accounting principle, or a change in the method of applying an accounting principle, that is inseparable from a change in accounting estimate. Therefore, this change would be considered a change in accounting estimate pursuant to Statement of Financial Accounting Standard No. 154 ''Accounting Changes and Error Corrections'' (SFAS 154) and would be accounted for prospectively.

Commenters believed that the change would be best described as:

• A change in accounting estimate;[304]

• A change in accounting principle that is inseparable from a change in accounting estimate; or[305]

• A change in accounting estimate effected by a change in accounting principle.[306]

We believe that any accounting change resulting from the changes in definitions and required pricing assumptions in Rule 4–10, should be treated as a change in accounting principle that is inseparable from a change in accounting estimate, which does not require retroactive revision. We note that pursuant to AU 420.13, such a change requires recognition in the independent auditor's report through the addition of an explanatory paragraph.

All commenters on the issue agreed that adoption of the rules should not require retroactive revision of past reserves estimates.[307] Some believed retroactive revision of reserves estimates would be very burdensome or impossible because such data was not maintained.[308] We agree with those commenters and believe that no retroactive revisions will be necessary.

Three commenters recommended that the FASB revise Statement of Financial Accounting Standard No. 19 (SFAS 19) to include unconventional resources currently accounted for as mining activities and also provide guidance that no retroactive revisions would be required in that scenario.[309] We will continue to work with the FASB on this issue.

C. Differing Capitalization Thresholds Between Mining Activities and Oil and Gas Producing Activities

As noted elsewhere in this release, extraction of products such as bitumen now will be considered oil and gas producing activities, and not mining activities. Under current U.S. accounting guidance, costs associated with proven plus probable mining reserves may be capitalized for operations extracting products through mining methods, like bitumen. Under the new rules, bitumen extraction and operations that produce oil or gas through mining methods are included under oil and gas accounting rules, which only permit capitalization of costs associated with proved reserves.[310] Moreover, the mining guidelines do not provide specified percentages for establishing levels of certainty for proven or probable reserves for mining activities. It is possible that these differences could result in changing reserves estimates for these resources during the transition to the new rules.

One commenter believed that the industry would need guidance regarding how to transition operations that are disclosed and accounted for as mining operations to oil and gas disclosure and accounting.[311] It noted that this issue would be relevant not only coincident with the new rules, but could be relevant to future events, such as a coal mining company that in subsequent years changes its operations to in situ coal gasification.[312] That commenter believed that, without guidance, the change from mining treatment to oil and gas treatment could be considered a change in accounting principle which requires retroactive revision.[313] We acknowledge this commenter's concerns. With respect to resources formerly considered mining activities, we view the change from mining treatment to oil and gas treatment as a change in accounting principle that is inseparable from a change in accounting estimate, which does not require retroactive revision.

VIII. Application of Interactive Data Format to Oil and Gas Disclosures

In the Proposing Release, we sought comment on the desirability of rules that would permit, or require, oil and gas companies to present the tabular disclosures in Subpart 1200 in interactive data format in addition to the currently required format. Most commenters addressing the topic supported the use of XBRL for oil and gas disclosures.[314] They believed using interactive data would be very helpful to investors and analysts.[315]

However, they also recommended that the Commission wait until a well-developed taxonomy exists.[316] Some recommended that the Commission implement it in stages, initially with a voluntary program.[317] One commenter recommended that the SEC work with other groups like SPE, IASB, and the United Nations to ensure tags ultimately become the industry standard.[318]

We agree that much of the disclosures regarding oil and gas companies would be conducive to interactive data. We intend to continue to work on developing a taxonomy for such disclosure. Once a well-developed taxonomy is created, we will address this issue further. We are not, however, adopting interactive data requirements in this release. We will continue to consider whether to require interactive oil and gas disclosure filings in the future and, if so, when such filings should be required based on the development status of an oil and gas disclosure taxonomy.

IX. Implementation Date

A. Mandatory Compliance

We proposed to require companies to begin complying with the disclosure requirements for registration statements filed on or after January 1, 2010, and for annual reports on Forms 10–K and 20–F for fiscal years ending on or after December 31, 2009. A company may not apply the new rules to disclosures in quarterly reports prior to the first annual report in which the revised disclosures are required.

[303] See letters from CAQ, CFA, Eni, Grant Thornton, KPMG, and PWC.

[304] See letters from CAQ, Canadian Natural, CAPP, Deloitte, Devon, KPMG, Petrobras, PWC, Repsol, Shell, and StatoilHydro.

[305] See letter from Deloitte.

[306] See letter from Petro-Canada.

[307] See letters from Apache, CAQ, Canadian Natural, CAPP, Deloitte, Devon, Evolution, ExxonMobil, Petrobras, Petro-Canada, PWC, Repsol, Shell, StatoilHydro, and Total.

[308] See letters from Canadian Natural, Deloitte, Evolution, Petrobras, and Shell.

[309] See letters from CAQ, Petrobras, and PWC.

[310] See Rule 4–10(c) of Regulation S–X [17 CFR 210.4–10(c)].

[311] See letter from KPMG.

[312] See letter from KPMG.

[313] See letter from KPMG.

[314] See letters from Audit Policy, CFA, Deloitte, Devon, E&Y, ExxonMobil, PWC, Shell, Standard Advantage, StatoilHydro, and Zakaib.

[315] See letters from CFA, Devon, E&Y, StatoilHydro, and Zakaib.

[316] See letters from Audit Policy, Deloitte, Devon, E&Y, ExxonMobil, PWC, Shell, StatoilHydro, and Zakaib.

[317] See letters from Audit Policy, Devon, E&Y, PWC, StatoilHydro, and Zakaib.

[318] See letter from Zakaib.

Fifteen commenters agreed that a delayed compliance date would be helpful in allowing companies to familiarize themselves with the new disclosure requirements before having to comply with them.[319] Four commenters supported the proposed January 1, 2010 compliance date of Securities Act filings and Exchange Act filings related to fiscal periods ending on or after December 31, 2009.[320] However, one conditioned this approval upon the adoption of the rules before December 31, 2008.[321] Another suggested one year after adoption of the rules.[322]

Four commenters believed that the proposed compliance date would be too soon.[323] One recommended a compliance date of December 31, 2010 to enable companies to make necessary changes in IT systems and data processing.[324] Another noted the magnitude of the proposed changes, length of time to design, program and implement system changes, and the goal of getting the best possible disclosure.[325] One commenter suggested delaying implementation for two years after adoption.[326]

We continue to believe that the proposed compliance dates are appropriate. However, as we discuss our revisions with the FASB and IASB, we will consider whether to delay the compliance date further.

B. Voluntary Early Compliance

Seven commenters recommended that early compliance not be permitted to maintain consistency and comparability of disclosure among issuers, which could be misleading or confusing to investors.[327] However, one commenter believed that the Commission should permit early adoption of the new rules because companies with different fiscal year ends are not comparable anyway.[328] One commenter suggested that the Commission permit companies to provide the new disclosures supplementally.[329] We agree that voluntary compliance may make disclosures incomparable. Therefore, companies may not elect to follow the new disclosure rules prior to the effective date.

X. Paperwork Reduction Act

A. Background

Our new rules and amendments contain ''collection of information'' requirements within the meaning of the Paperwork Reduction Act of 1995 (''PRA'').[330] We submitted the new rules and amendments to the Office of Management and Budget (OMB) for review in accordance with the PRA.[331] OMB has approved the revisions. The titles for these collections of information are:

(1) ''Regulation S–K'' (OMB Control No. 3235–0071);[332]
(2) ''Industry Guides'' (OMB Control No. 3235–0069);
(3) ''Regulation S–X'' (OMB Control No. 3235–0009);
(4) ''Form S–1'' (OMB Control No. 3235–0065);
(5) ''Form S–4'' (OMB Control No. 3235–0324);
(6) ''Form F–1'' (OMB Control No. 3235–0258);
(7) ''Form F–4'' (OMB Control No. 3235–0325);
(8) ''Form 10'' (OMB Control No. 3235–0064);
(9) ''Form 10–K'' (OMB Control No. 3235–0063); and
(10) ''Form 20–F'' (OMB Control No. 3235–0063).

We adopted all of the existing regulations and forms pursuant to the Securities Act and the Exchange Act. These regulations and forms set forth the disclosure requirements for annual reports[333] and registration statements that are prepared by issuers to provide investors with the information they need to make informed investment decisions in registered offerings and in secondary market transactions. The industry guides supplement the existing regulations and forms and provide guidance with respect to industry-specific disclosures.

Our amendments to these existing forms are intended to modernize and update our reserves definitions to better reflect changes in the oil and gas industry and markets and new technologies that have occurred in the decades since the current rules were adopted, including expanding the scope of permissible technologies for establishing certainty levels of reserves, reserves classifications that a company can disclose in a Commission filing, and the types of resources that can be included in a company's reserves, as well as providing information regarding a company's internal controls over reserves estimation and the qualifications of person preparing reserves estimates or conducting reserves audits. The new rules and amendments also are intended to codify, modernize, and centralize the disclosure items for oil and gas companies in Regulation S–K. Finally, the new rules and amendments are intended to harmonize oil and gas disclosures by foreign private issuers with disclosures by domestic companies. Overall, the new rules and amendments attempt to provide improved disclosure about an oil and gas company's business and prospects without sacrificing clarity and comparability, which provide protection and transparency to investors.

The hours and costs associated with preparing disclosure, filing forms, and retaining records constitute reporting and cost burdens imposed by the collection of information. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid control number.

Many, but not all, of the information collection requirements related to annual reports and registration statements will be mandatory. There is no mandatory retention period for the information disclosed, and the information will be publicly available on the EDGAR filing system.

B. Summary of Information Collections

The new rules and amendments increase existing disclosure burdens for annual reports on Forms 10–K[334] and

[319] See letters from Apache, Chevron, Davis Polk, Deloitte, ExxonMobil, KPMG, Newfield, Petrobras, Petro-Canada, PWC, Ryder Scott, Shell, Southwestern, Talisman, and Total.

[320] See letters from Davis Polk, ExxonMobil, Shell, and StatoilHydro.

[321] See letter from ExxonMobil.

[322] See letter from Talisman.

[323] See letters from Apache, Petrobras, PWC, and Total.

[324] See letter from Petrobras.

[325] See letter from Apache.

[326] See letter from Devon.

[327] See letters from Davis Polk, Devon, ExxonMobil, Petrobras, Ryder Scott, Shell, and Wagner.

[328] See letter from Evolution.

[329] See letter from Davis Polk.

[330] 44 U.S.C. 3501 *et seq.*

[331] 44 U.S.C. 3507(d) and 5 CFR 1320.11.

[332] The paperwork burden from Regulation S–K and the Industry Guides is imposed through the forms that are subject to the disclosures in Regulation S–K and the Industry Guides and is reflected in the analysis of those forms. To avoid a Paperwork Reduction Act inventory reflecting duplicative burdens, for administrative convenience, we estimate the burdens imposed by each of Regulation S–K and the Industry Guides to be a total of one hour.

[333] The pertinent annual reports are those on Forms 10–K and 20–F.

[334] The disclosure requirements regarding oil and gas properties and activities are in Form 10–K as well as the annual report to security holders required pursuant to Rule 14a–3(b) [17 CFR 240.14a–3(b)]. Form 10–K permits the incorporation by reference of information from the Rule 14a–3(b) annual report to security holders to satisfy the Form 10–K disclosure requirements. The analysis that follows assumes that companies would either provide the proposed disclosure in a Form 10–K or incorporate the required disclosure into the Form 10–K by reference to the Rule 14a–3(b) annual report to security holders if the company is subject to the proxy rules. This approach takes into account the burden from the proposed disclosure

Continued

20–F and registration statements on Forms 10, 20–F, S–1, S–4, F–1, and F–4 by creating the following new disclosure requirements, many of which were requested by industry participants:

• Disclosure of reserves from non-traditional sources (*i.e.*, bitumen, shale, coalbed methane) as oil and gas reserves;

• Optional disclosure of probable and possible reserves;

• Optional disclosure of oil and gas reserves' sensitivity to price;

• Disclosure of the company's progress in converting proved undeveloped reserves into proved developed reserves, including those that are held for five years or more and an explanation of why they should continue to be considered proved;

• Disclosure of technologies used to establish reserves in a company's initial filing with the Commission and in filings which include material additions to reserves estimates;

• The company's internal controls over reserves estimates and the qualifications of the technical person primarily responsible for overseeing the preparation or audit of the reserves estimates;

• If a company represents that disclosure is based on the authority of a third party that prepared the reserves estimates or conducted a reserves audit or process review, filing a report prepared by the third party; and

• Disclosure based on a new definition of the term ''by geographic area.''

In addition, the amendments harmonize the disclosure requirements that apply to foreign private issuers with the disclosure requirements that apply to domestic issuers with respect to oil and gas activities. In particular, foreign private issuers must disclose the information required by Items 1205 through 1208 of Regulation S–K regarding drilling activities, present activities, delivery commitments, wells, and acreage, which previously were not specified in Appendix A to Form 20–F. These disclosure items codify the substantive disclosures called for by Items 4 through 8 of Industry Guide 2, although much of this disclosure may have been disclosed by some companies under the more general discussions of business and property on that form.

C. Revisions to PRA Burden Estimates

For purposes of the PRA, we estimated, in the Proposing Release, the total annual increase in the paperwork burden for all affected companies to comply with our proposed collection of information requirements to be approximately 7,472 hours of in-house company personnel time and to be approximately $1,659,000 for the services of outside professionals.[335] These estimates included the time and the cost of preparing and reviewing disclosure and filing documents. Our methodologies for deriving the above estimates are discussed below.

Our estimates represented the burden for all oil and gas companies that file annual reports or registration statements with the Commission. Based on filings received during the Commission's last fiscal year, we estimate that 241 oil and gas companies file annual reports and 67 oil and gas companies file registration statements. Most of the information called for by the new disclosure requirements, including the optional disclosure items, is readily available to oil and gas companies and includes information that is regularly used in their internal management systems. These disclosures include:

• Disclosure of reserves from non-traditional sources (*i.e.*, bitumen, shale, coalbed methane) as oil and gas reserves;

• Optional disclosure of probable and possible reserves;

• Optional disclosure of oil and gas reserves' sensitivity to price;

• Disclosure of the company's progress in converting proved undeveloped reserves into proved developed reserves, including those that are held for five years or more and an explanation of why they should continue to be considered proved;

• Disclosure of technologies used to establish reserves in a company's initial filing with the Commission and in filings which include material additions to reserves estimates;

• The company's internal controls over reserves estimates and the qualifications of the technical person primarily responsible for overseeing the preparation or audit of the reserves estimates;

• If a company represents that disclosure is based on the authority of a third party that prepared the reserves estimates or conducted a reserves audit or process review, filing a report prepared by the third party; and

• Disclosure based on a new definition of the term ''by geographic area.''

We estimated that, on average, each company would incur a burden of 35 hours to prepare these disclosures in an annual report or registration statement.

The amendments also apply several disclosure items to foreign private issuers that previously did not apply to them. As noted above, many of these disclosure items, such as drilling activities, wells and acreage, require the issuer to provide more specificity about its business and property. Foreign private issuers that do not currently provide such specificity would incur an added burden to present such disclosures in their filings. In the Proposing Release, we estimated that this burden would be 20 hours per foreign private issuer.

We received few comments regarding our estimates. Several large oil companies, and an industry organization that primarily represents large oil companies, believed that the estimates were too low. They believed that the new rules and amendments would increase their burden by 10,000 to 15,000 hours per year. However, these commenters included the initial cost to change their internal systems to provide the new required disclosures in their estimates. Based on conversations with these commenters, the staff understands that they believed that the ongoing burden would be approximately one-third of that estimate. For purposes of its Paperwork Reduction Act estimate, the staff considers the ongoing annual burden and spreads the initial transitional burden of compliance with new rules and regulations over a three-year period.

In addition, these commenters indicated that the two most significant burdens that stemmed from the proposed use of different prices for disclosure and accounting purposes and the increased detail in disclosures that would result from the proposed definition of the term ''geographic area'' and the proposed disclosure by type of accumulation. It should be noted that these commenters have significant reserves spread worldwide. Some of these large companies have as much as 10,000 times the amount of reserves of the median oil and gas company. These large companies likely would be more significantly impacted by the level of detailed disclosure that the proposals would have required compared to the vast majority of oil and gas companies in our reporting system, which do not have such extensive global operations. Therefore, we do not believe that the estimate provided by those large oil and gas companies necessarily would be applicable to most oil and gas companies. However, in response to the concerns that they expressed, the final rules do not require the use of different

requirements that are included in both Form 10–K and Regulation 14A or 14C.

[335] For administrative convenience, the presentation of the totals related to the paperwork burden hours have been rounded to the nearest whole number and the cost totals have been rounded to the nearest thousand.

prices for disclosure and full cost accounting purposes. We also intend to continue to work with the FASB to align the accounting standards with that pricing mechanism. In addition, we have significantly reduced the level of detailed geographic and product disclosure that the rules require. Finally, we are providing for a substantial transition period to allow companies to adjust their systems to comply with the new rules. We believe that these changes will help to mitigate the increased burden of the new rules.

We do, however, believe that our initial burden estimates may have been too low. We are therefore adjusting our burden estimate to reflect an additional increase of 100 hours per company per year. In addition, we are increasing our burden estimate for foreign private issuers by an additional 150 hours per company per year. Consistent with current Office of Management and Budget estimates and recent Commission rulemakings, we estimate that 25% of the burden of preparation of registration statements on Forms S–1, S–4, F–1, F–4, 10, and 20–F is carried by the company internally and that 75% of the burden is carried by outside professionals retained by the issuer at an average cost of $400 per hour.[336] We estimate that 75% of the burden of preparation of annual reports on Form 10–K or Form 20–F is carried by the company internally and that 25% of the burden is carried by outside professionals retained by the company at an average cost of $400 per hour. The portion of the burden carried by outside professionals is reflected as a cost, while the portion of the burden carried by the company internally is reflected in hours. The following tables summarize the additional changes to the PRA estimates:

TABLE 1—CALCULATION OF INCREMENTAL PAPERWORK REDUCTION ACT BURDEN ESTIMATES FOR EXCHANGE ACT PERIODIC REPORTS

Form	Annual responses	Incremental hours/form	Incremental burden	75% Issuer	25% Professional	$400 Professional cost
	(A)	(B)	(C)=(A)*(B)	(D)=(C)*0.75	(E)=(C)*0.25	(F)=(E)*$400
10–K§ [337]	206	100	20,600	15,450	5,150	2,060,000
20–F	35	150	5,250	3,938	1,312	525,000
Total	241	....	25,850	19,388	6,462	2,585,000

TABLE 2—CALCULATION OF INCREMENTAL PAPERWORK REDUCTION ACT BURDEN ESTIMATES FOR SECURITIES ACT REGISTRATION STATEMENTS AND EXCHANGE ACT REGISTRATION STATEMENTS

Form	Annual responses	Incremental hours/form	Incremental burden	25% Issuer	75% Professional	$400 Professional cost
	(A)	(B)	(C)=(A)*(B)	(D)=(C)*0.25	(E)=(C)*0.75	(F)=(E)*$400
10	5	100	500	125	375	150,000
20–F	2	150	300	75	225	90,000
S–1	38	100	3,800	950	2,850	1,140,000
S–4	17	100	1,700	425	1,275	510,000
F–1	2	150	300	75	225	90,000
F–4	3	150	450	112.5	337.5	135,000
Total	67	....	7,050	1762.5	5,287.5	2,115,000

D. Request for Comment

We request comment in order to evaluate the accuracy of our estimates of the burden of the revised information collections. Any member of the public may direct to us any comments concerning the accuracy of these burden estimates. Persons who desire to submit comments on the collection of information requirements should direct their comments to the OMB, Attention: Desk Officer for the Securities and Exchange Commission, Office of Information and Regulatory Affairs, Washington, DC 20503, and should send a copy of the comments to Secretary, Securities and Exchange Commission, 100 F Street, NE., Washington, DC 20549–1090, with reference to File No. S7–15–08. Requests for materials submitted to the OMB by us with regard to this collection of information should be in writing, refer to File No. S7–15–08, and be submitted to the Securities and Exchange Commission, Records Management Branch, 100 F Street, NE., Washington, DC 20549–1126. Because OMB is required to make a decision concerning the collections of information between 30 and 60 days after publication, your comments are best assured of having their full effect if OMB receives them within 30 days of publication.

XI. Cost-Benefit Analysis

A. Background

We are adopting revisions to the oil and gas reserves disclosure regime of Regulation S–K and Regulation S–X under the Securities Act of 1933 and the Securities Exchange Act of 1934 and Industry Guide 2. The revisions are intended to modernize and update oil and gas disclosure. The oil and gas industry has experienced significant changes since the Commission initially adopted its current rules and disclosure

[336] In connection with other recent rulemakings, we have had discussions with several private law firms to estimate an hourly rate of $400 as the average cost of outside professionals that assist issuers in preparing disclosures and conducting registered offerings.

[337] The burden estimates for Form 10–K assume that the requirements are satisfied by either including information directly in the annual reports or incorporating the information by reference from the Rule 14a–3(b) annual report to security holders.

regime between 1978 and 1982, including advancements in technology and changes in the types of projects in which oil and gas companies invest. The revisions also are intended to provide investors with improved disclosure about an oil and gas company's business and prospects without sacrificing clarity and comparability.

B. Description of New Rules and Amendments

Currently, Industry Guide 2 specifies many of the disclosure guidelines for oil and gas companies. The Industry Guide calls for disclosure relating to reserves, production, property, and operations in addition to that which is required by Regulation S–K. Generally, the new rules and amendments codify and update the existing Industry Guide 2 disclosures in a new Subpart 1200 of Regulation S–K, clarify the level of detail required to be disclosed, and require reserves disclosure in a tabular presentation. The changes relate primarily to disclosure of the following:

• Disclosure of reserves from non-traditional sources (*e.g.*, bitumen, shale) as oil and gas reserves;
• Optional disclosure of probable and possible reserves;
• Optional disclosure of oil and gas reserves' sensitivity to price;
• Disclosure of the company's progress in converting proved undeveloped reserves into proved developed reserves, including those that are held for five years or more and an explanation of why they should continue to be considered proved;
• Disclosure of technologies used to establish reserves in a company's initial filing with the Commission and in filings which include material additions to reserves estimates;
• The company's internal controls over reserves estimates and the qualifications of the technical person primarily responsible for overseeing the preparation or audit of the reserves estimates;
• If a company represents that disclosure is based on the authority of a third party that prepared the reserves estimates or conducted a reserves audit or process review, filing a report prepared by the third party; and
• Disclosure based on a new definition of the term ''by geographic area.''

The new rules and amendments also make revisions and additions to the definitions section of Rule 4–10 of Regulation S–X. These revisions update and extend reserves definitions to reflect changes in the oil and gas industry and new technologies. In particular, the new and revised definitions:

• Expand the definition of ''oil and gas producing activities'' to include the extraction of hydrocarbons from oil sands, shale, coalbeds, or other natural resources and activities undertaken with a view to such extraction;
• Add a definition of ''reasonable certainty'' to provide better guidance regarding the meaning of that term;
• Add a definition of ''reliable technology'' to permit the use of new technologies to establish proved reserves;
• Define probable and possible reserves estimates; and
• Add definitions to explain new terms used in the revised definitions.

In addition, the amendments harmonize the disclosure requirements that apply to foreign private issuers with the disclosure requirements that apply to domestic issuers with respect to oil and gas activities. In particular, the amendments to Form 20–F will require foreign private issuers to disclose the information required by Items 1205 through 1208 of Regulation S–K regarding drilling activities, present activities, delivery commitments, wells, and acreage, which are not currently specified under Appendix A to Form 20–F, although much of this disclosure is often disclosed by companies under the more general discussions of business and property on that form.

C. Benefits

We expect that the new rules and amendments will increase transparency in disclosure by oil and gas companies by providing improved reporting standards. The revisions to the definitions should align our disclosure rules with the realities of the modern oil and gas markets. For example, we believe that the inclusion of bitumen and other resources from continuous accumulations as oil and gas producing activities is consistent with company practice to treat these operations as part of, rather than separate from, their traditional oil and gas producing activities. Similarly, the expansion of permissible technologies for determining certainty levels of reserves recognizes that companies now take advantage of these technological advances to make business decisions. We expect these new rules and amendments to improve disclosure by aligning the required disclosure more closely with the way companies conduct their business.

Allowing companies to disclose probable and possible reserves is designed to improve investors' understanding of a company's unproved reserves. For those companies that already disclose such reserves on their Web sites, the new rules and amendments permit them to unify such disclosures into a single, filed document. Disclosure of these categories of reserves beyond proved reserves may foster better company valuations by investors, creditors, and analysts, thus improving capital allocation and reducing investment risk. Because some of the disclosure items are optional, the amount of increased transparency will depend on the extent to which companies elect to provide the additional disclosures permitted under the new rules. If companies elect not to provide the optional disclosure, then the benefits from increased transparency would be limited to the extent that the new rules improve the transparency of proved reserves disclosure.

By permitting increased disclosure and promoting more consistency and comparability among disclosures, the new rules and amendments provide a mechanism for oil and gas companies to seek more favorable financing terms through more disclosure and increased transparency. Investors may be able to request such additional disclosure in Commission filings during negotiations regarding bond and debt covenants. Thus, we expect that, as a result of competing factors in the marketplace, the new rules and amendments will result in increased transparency, either because companies elect to voluntarily provide increased disclosure, or because investors may discount companies that do not do so. We believe that the benefits and costs of disclosing unproved reserves ultimately will be determined by market conditions, rather than regulatory requirements.

We expect that permitting companies to disclose probable and possible reserves will increase market transparency, provide investors with more reserves information, and allow for more accurate production forecasts. By relating standards used in deterministic methods to comparable percentage thresholds used in probabilistic methods for establishing a given level of certainty, the new rules and amendments should result in increased standardization in reporting practices which would promote comparability of reserves across companies. The new rules would define the term ''reliable technology'' to permit oil and gas companies to prepare their reserves estimates using new types of technology that companies are not permitted to use under the current rules. This new definition also is designed to encompass new technologies as they are developed in the future, thereby providing investors and the market with a more comprehensive understanding of a company's estimated reserves.

We expect that replacing the Industry Guide with new Regulation S–K items will provide greater certainty because the disclosure requirements would be in rules established by the Commission. In addition, we believe that disclosure of reserves concentrated in particular countries should provide better information to investors regarding the geopolitical risk to which some companies may be exposed. Overall, we believe that the amendments, as a whole, will provide investors with more information that management uses to make business decisions in the oil and gas industry.

1. Average Price and First of the Month Price

The revision to change the price used to calculate reserves from a year-end single-day price to a historical average price over the company's most recently ended fiscal year is expected to reduce the effects of seasonality. In particular, many commenters suggested the use of a 12-month average price to mitigate the risk of a year-end price affected by short-term price volatility such that it does not reflect the true nature of a company investment, planning, and performance. Our Office of Economic Analysis studied the publicly-available pricing data and found evidence of year-end price volatility. The historical volatility of year-end prices is between 16 percent and 41 percent higher than the volatility of annual average prices depending on the grade and geography of oil or gas prices considered. This difference demonstrates variability in oil and gas prices, likely due to seasonal demands, that does not reflect long term fundamental values, but that cannot be immediately corrected due to the costs of transportation and speed of delivery. Given this variability, it is likely that a 12-month average price will yield better reserves estimates—that reflect management planning and investment to the extent that they discount the short-term component of oil and gas prices—than a year-end spot price.

Many of the commenters to the Proposing Release supported the use of a historical price, even though this approach may be less useful in determining the fair value of a company's reserves compared to a futures market price. We believe investors are concerned not only about the quantity of a company's reserves, but also about the profitability of those reserves. We also recognize that some reserves will be of more value than others due to extraction and transportation costs. As a result, since the new rules and amendments require the use of a single price to estimate reserves and since that price may not be as informative of value as a futures price, the new rules and amendments also gives companies the option of providing a sensitivity analysis and reporting reserves based on additional price estimates.

If companies elect to provide a sensitivity analysis, we expect this to benefit investors by allowing them to formulate better projections of company prospects that are more consistent with management's planning price and prices higher and lower that may reasonably be achieved. In particular, it allows companies the flexibility to communicate how their reserves would change under alternative economic conditions, including those that they may believe better reflect their future prospects. We expect that companies would be more likely to adopt a sensitivity analysis approach if investors and other market participants determine that this information would reduce investment risk, or if companies believe such disclosure will reduce the cost of capital formation. The new rules and amendments should result in increased price stability in determining whether reserves are economically producible. This should mitigate seasonal effects, resulting in reserves estimates that more closely reflect those used by management in planning and investment decisions. We expect this to allow for more accurate company assessments and improve projections of company prospects.

In addition to an average annual price, many of the commenters suggested that the price be computed on the first day of the month. Two reasons were given. First, beginning month prices would allow an additional month of preparation time in calculating reserves for financial reporting. Second, some commenters suggested that month-end, and in particular year-end, prices were subject to additional short-term volatility because many oil and gas financial contracts expire on those days, resulting in higher than normal trading activity. While the staff of the Office of Economic Analysis did not find systematic evidence of increased volatility around month-end or year-end oil and gas prices relative to other days in the month, we agree that additional preparation time is beneficial because reserves estimations require significant time and resources. An additional month would help reduce errors that might otherwise result from the financial reporting time constraints.

Finally, we believe that revising the full cost accounting method to use the same pricing mechanism as the reserves disclosure requirements should provide consistency between the disclosure and accounting presentations. The use of a single pricing method should also minimize the incremental burden placed on companies as a result of the rule changes because they would not be required to prepare two separate estimates.

2. Probable and Possible Reserves

We anticipate that disclosure of probable and possible reserves, if companies elect to do so, will allow investors, creditors, and other users to better assess a company's reserves. In addition, the tabular format for disclosing probable and possible reserves should reduce investor search costs by making it easier to locate reserves disclosures and facilitating comparability among oil and gas companies.

While we recognize that many companies already communicate with investors about their unproved and other reserves through alternative means, such as company Web sites or press releases, some commenters remarked that an objective comparison among companies is difficult because different companies have defined such reserves classifications differently. We believe that permitting disclosure of this information in Commission filings will provide a more consistent means of comparison because disclosure in our filings must comply with our definitions. Although our new rules make disclosure of probable and possible reserves optional, and large oil and gas producers suggested in their comment letters that such disclosure would be of limited benefit because of the relative uncertainty of those estimates, we believe that competitive pressures within the industry might make it beneficial for large producers to disclose this information. Increased disclosure might, for example, improve credit quality and lower the cost of debt financing, or reduce the risk associated with business transactions between the company and its customers or suppliers. Regardless, since the disclosure decision is voluntary, it should occur only to the extent that companies find that the benefits justify the costs of doing so.

We believe that permitting the disclosure of probable and possible reserves will benefit smaller companies, in particular. Larger issuers tend to already have large amounts of proved reserves. The new rules and amendments permit smaller companies, who often participate in a significant amount of exploratory activity, to better disclose their business prospects. Consequently, we anticipate that the new rules and amendments could lead to efficiencies in capital formation, as more information will be available regarding the prospects of smaller issuers.

3. Reserves Estimate Preparers and Reserves Auditors

We believe that investors would benefit from a greater level of assurance with respect to the reliability of reserve estimates, particularly if companies are allowed to disclose unproved reserves because unproved reserves are inherently less certain than proved reserves. We proposed disclosure requirements relating to whether the person primarily responsible for preparing reserves estimates or conducting a reserves audit, if the company represents that it has enlisted a third party to conduct a reserves audit, met a specified list of qualifications based on the Society of Petroleum Engineers's reserves audit guidelines. However, commenters expressed concern that many of these qualifications such as membership in professional societies were not standardized worldwide. Without control over those standards, the disclosures would not be comparable. We agree with those commenters and, as suggested, have adopted a more principles-based disclosure requirement. Under the adopted rules, a company must disclose its internal controls over reserves estimations and disclose the qualifications of the primary technical person in charge of overseeing the reserves estimations or reserves audit. We believe that disclosure of the individual qualifications, rather than simple acknowledgement of meeting certain criteria, which may differ within countries, will provide investors with better information to compare companies and the qualifications of persons in charge of the reserves estimations and reserves audits, which should enable more accurate assessments of the quality of audit reports. We believe that disclosure of a company's internal controls over reserves estimates will allow investors to assess whether a company has implemented appropriate controls without dictating to companies specified criteria for establishing those controls.

Although we do not expect all companies to undertake a third-party reserves audit because our rules do not require such a reserves audit, third party participation in the estimation of reserves should add credibility to a company's public disclosure. The opinion of an objective, qualified person on the reserves estimates is designed to increase the reliability of these estimates and investor confidence.

4. Development of Proved Undeveloped Reserves

The new rules and amendments also require disclosure of a company's progress in developing undeveloped reserves and the reasons why any PUDs have remained undeveloped for five years or more. We believe that such disclosure supplements our amendments that ease the requirements for recognizing PUDs and thereby should increase the amount of PUDs disclosed in filings, even though the properties representing such proved reserves have not yet been developed and therefore do not provide the company with cash flow. We believe that the disclosure requirements will increase the accountability of companies that disclose reserves for extended periods of time without adequate justification for their failure to develop those reserves.

5. Disclosure Guidance

The release also provides guidance about the type of information that companies should consider disclosing in Management's Discussion and Analysis, and allows companies to include this information with the relevant tables. Providing the additional guidance should assist companies in preparing their disclosure, improving the quality and consistency of this disclosure. Locating this discussion with the tables themselves should benefit investors by simplifying the presentation of disclosure, and providing insight into the information disclosed in the tables.

6. Updating of Definitions Related to Oil and Gas Activities

The new rules and amendments also update the definition of the term ''oil and gas producing activities'' as well as updating or creating new definitions for other terms related to such activities, including ''proved oil and gas reserves'' and ''reasonable certainty.'' We believe that updating these definitions will help companies disclose oil and gas operations in the same way that companies manage and assess those operations. This includes resources extracted from nontraditional sources that companies consider oil and gas activities, which previously were excluded them from the definition of ''oil and gas producing activities.'' In addition, adding definitions for terms like ''reasonable certainty'' (which currently is in the definition of ''proved oil and gas reserves,'' but not defined) will provide companies with added guidance and assist them in providing consistent disclosures between companies.

7. Harmonizing Foreign Private Issuer Disclosure

We believe that the harmonization of foreign private issuer disclosure will help make disclosures of foreign private issuers more comparable with domestic companies. The oil and gas industry has changed significantly since the rules were adopted. Today, many companies have interests that span the globe. In addition, many of these projects are joint ventures between foreign private issuers and domestic companies. Having differing levels of disclosure for companies that may be participating in the same projects harms comparability between investment choices. The harmonization of foreign private issuer disclosure is intended to promote comparability among all oil companies.

D. Costs

We expect that the new rules and amendments will result in initial and ongoing costs to oil and gas companies. These burdens will vary significantly among companies. Based on disclosures in company filings, the largest oil and gas companies can have as much as 10,000 times the reserves of the median reporting oil and gas company. As would be expected, companies that have more reserves and larger operations will have a correspondingly larger amount of information that they must disclose and, therefore, the burden of complying with our disclosure requirements would be greater for larger companies.

Although we are adding a new subpart to Regulation S–K to set forth the disclosure requirements that are unique to oil and gas companies, the subpart, for the most part, codifies the substantive disclosure called for by Industry Guide 2. The disclosure requirements have been updated and clarified, and require the disclosure to be presented in a tabular format, where appropriate.

Although many companies already present this information in tabular form, for companies that do not, this requirement could impose a burden on companies as they transition from a narrative to tabular disclosure format. We expect, however, that any increased preparation costs would be highest in the first year after adoption, but would decline in subsequent years as companies adjust to the new format. We think this burden is justified because tabular disclosure will increase comparability and facilitate understanding and analysis by investors.

1. Probable and Possible Reserves

Allowing disclosure of probable and possible reserves could create an increased risk of litigation because these categories of reserves estimates are less certain than proved reserves. Companies may choose not to disclose such reserves, in part, because of the risk of incurring litigation costs to defend their disclosures due to the increased uncertainty of these categories. Disclosure of probable and possible reserves may also result in revealing competitive information because it might reveal a company's business strategy, such as the geographic location and nature of its exploration and discoveries. For example, if geographical detail can be inferred from estimates of unproved reserves, this might reveal information about the value of a company's assets to competitors and could put the producer at a competitive disadvantage. We have reduced the level of geographical detail to reduce the burden on companies, while still providing sufficient information to investors regarding concentrations of risk, including political risk.

We expect companies will incur costs in preparing the additional disclosures such as calculating and aggregating the reserve projections in a prescribed format. However, if probable and possible categories of reserves have different extraction cost structures and they are not disclosed separately from proved reserves, this could result in increased uncertainty in an investor's assessment of a company's prospects.

Companies also expressed concern that mandatory disclosure of probable and possible reserves could expose them to increased litigation risk. We believe that making these disclosures voluntary mitigates these concerns. Companies unwilling to bear the added risk can simply opt not to provide this disclosure.

2. Reserves Estimate Preparers and Reserves Auditors

If a company chooses to use a third party to prepare or audit reserve estimates, it will incur costs to hire these outside consultants. The new rules and amendments do not require companies to hire such a person. If enough companies that currently do not use such consultants begin to hire them, we believe that industry wages could potentially increase due to increased demand for reserves calculating specialists unless that demand is compensated by an increase in the supply of such persons. If wages increased, then all companies, not just those employing third party consultants, would incur added costs.

Large companies may be less likely to hire third parties because they tend to have staff to make reserves estimates. However, if such large companies chose to hire third-party consultants, third parties would expend significantly more effort on such projects than for smaller companies because larger companies have more properties to evaluate. Thus, we expect third-party fees, and the time required to conduct such projects, would scale upwards with the quantity of company reserves.

Disclosure of unproved reserves without third-party certification may present a risk with respect to smaller oil and gas producers because smaller companies are likely to have less in-house expertise and ability to accurately estimate such reserves than larger companies. However, we understand that the vast majority of smaller oil and gas companies already hire third parties to estimate their reserves or certify their estimates.

3. Consistency With IASB

Some commenters remarked that the International Accounting Standards Board is currently preparing a set of guidelines for oil and gas extractive activities, including definitions of oil and gas reserves, and recommended that the Commission align its regulations with those guidelines. We intend to monitor this initiative and work with the IASB, but our new rules may differ from the guidelines ultimately established by the International Accounting Standards Board. This could make it more difficult for investors to compare foreign and domestic companies.

4. Change in Pricing Mechanism

We do not anticipate significant costs with the change in pricing mechanisms for established reserves. Companies simply will apply a different price scenario to determine the economic producibility of reserves. It is possible that the use of a 12-month average price may reduce the cost of disclosure because it should reduce the volatility of reserves estimates and therefore reduce the need to make significant adjustments to those estimates on a yearly basis due to daily price swings.

5. Disclosure of PUD Development

The required disclosure of a company's progress in developing PUDs will increase the cost of reporting. However, we believe that companies regularly track their progress in this arena. Until a company develops a property, it cannot begin to realize the cash flows from production and the actual sale of products. Thus, the development of reserves is of utmost importance to an oil and gas company's business.

6. Increased Geographic Disclosure

The requirements to provide increased geographic disclosure of reserves and production, in certain circumstances, may increase the amount of disclosure that a company must present. However, because the threshold that we are adopting in the release is 15% of the company's total reserves, a company would be required to disclose, at most, reserves and production in six countries. Considering the relatively large proportion of reserves that must exist in a country before a company is required to provide country-level disclosure, we believe that such information is readily available to companies. As noted in the body of this release, we have attempted to draft this provision to minimize any competitive harm that such disclosure may cause a company.

7. Harmonizing Foreign Private Issuer Disclosure

The harmonization of foreign private issuer disclosure regarding oil and gas activities may increase the burden on foreign private issuers. However, it is our understanding that the large foreign private issuers already voluntarily provide disclosure comparable to the level required from domestic companies. Much of the added new disclosure relates to the day-to-day business and properties of these companies, including drilling activities, number of wells and acreage. This is information that is central to the activities of oil and gas companies, and therefore is readily known to these companies. We believe that applying Subpart 1200 to these companies could prompt more detailed disclosure regarding these activities, which would cause these companies to incur some cost. The provision permitting foreign private issuers to omit disclosures if prohibited from making those disclosures by their home jurisdiction could mitigate some of these costs.

XII. Consideration of Burden on Competition and Promotion of Efficiency, Competition, and Capital Formation

Securities Act Section 2(b) [338] and Section 3(f) of the Exchange Act [339] require us, when engaging in rulemaking where we are required to consider or determine whether an action is necessary or appropriate in the public interest, to consider, in addition to the protection of investors, whether the action will promote efficiency, competition, and capital formation. Section 23(a)(2) of the Exchange Act [340] requires us, when adopting rules under the Exchange Act, to consider the impact that any new rule would have on competition. In addition, Section 23(a)(2) prohibits us from adopting any rule that would impose a burden on competition not necessary or appropriate in furtherance of the purposes of the Exchange Act.

We expect the new rules and amendments to increase efficiency and enhance capital formation, and thereby benefit investors, by providing the market with better information based on updated technology as well as increased information covering a broader range of reserves classifications held by a company and reserves found in non-traditional sources of oil and gas. Such increased and improved information should permit investors to better assess a company's prospects. In particular, the existing prohibitions against disclosing reserves other than proved reserves, using modern technology to determine the certainty level of reserves, and including resources from non-traditional sources can lead to incomplete disclosures about a company's actual resources and prospects. The new rules and amendments are designed to better align the disclosure requirements with the way companies make business decisions.

We believe that permitting the disclosure of probable and possible reserves will benefit smaller companies, in particular. Larger issuers tend to already have large amounts of proved reserves. The new rules and amendments permit smaller companies, who often participate in a significant amount of exploratory activity, to better disclose their business prospects. Consequently, we anticipate that the new rules and amendments could lead to efficiencies in capital formation, as more information will be available regarding the prospects of smaller issuers.

The effects of the new rules and amendments on competition are difficult to predict, but it is possible that permitting public issuers to disclose probable and possible reserves will lead to a reallocation of capital, as companies that previously could show few proved reserves will be able to disclose a broader range of its business prospects, making it easier for these issuers to raise capital and compete with companies that have large proved reserves. Although our new rules make disclosure of probable and possible reserves optional, and large oil and gas producers suggested in their comment letters that such disclosure would be of limited benefit because of the relative uncertainty associated with such reserves, we believe that competitive pressures within the industry might make it beneficial for large producers to disclose this information. Increased disclosure might, for example, improve credit quality and lower the cost of debt financing, or reduce the risk associated with business transactions between the company and its customers or suppliers.

XIII. Final Regulatory Flexibility Analysis

We have prepared this Final Regulatory Flexibility Analysis in accordance with Section 603 of the Regulatory Flexibility Act.[341] This analysis relates to the modernization of the oil and gas disclosure requirements. An Initial Regulatory Flexibility Analysis (IRFA) was prepared in accordance with the Regulatory Flexibility Act in conjunction with the Proposing Release. The Proposing Release included, and solicited comment on, the IRFA.

A. Reasons for, and Objectives of, the New Rules and Amendments

The Commission adopted the current disclosure regime for oil and gas producing companies in 1978 and 1982, respectively. Since that time, there have been significant changes in the oil and gas industry and markets, including technological advances, and changes in the types of projects in which oil and gas companies invest their capital. On December 12, 2007, the Commission published a Concept Release on possible revisions to the disclosure requirements relating to oil and gas reserves.[342] Prior to our issuance of the Concept Release, many industry participants had expressed concern that our disclosure rules are no longer in alignment with current industry practices and therefore have limited usefulness to the market and investors.

Our new rules and amendments to these existing forms are intended to modernize and update our reserves definitions to reflect changes in the oil and gas industry and markets and new technologies that have occurred in the decades since the current rules were adopted, including expanding the scope of permissible technologies for establishing certainty levels of reserves, reserves classifications that a company can disclose in a Commission filing, and the types of resources that can be included in a company's reserves, as well as providing information regarding the objectivity and qualifications of any third party primarily responsible for preparing or auditing the reserves estimates, if the company represents that it has enlisted a third party to conduct a reserves audit, and the qualifications and measures taken to assure the independence and objectivity of any employee primarily responsible for preparing or auditing the reserves estimates. The amendments also harmonize our full cost accounting rules with the changes that we are adopting with respect to disclosure of oil and gas reserves. The new rules and amendments also are intended to codify, modernize and centralize the disclosure items for oil and gas companies into Regulation S–K. Finally, the new rules and amendments are intended to harmonize oil and gas disclosures by foreign private issuers with disclosures by domestic companies. Overall, the new rules and amendments attempt to provide improved disclosure about an oil and gas company's business and prospects without sacrificing clarity and comparability, which provide protection and transparency to investors.

B. Significant Issues Raised by Commenters

We did not receive comments specifically addressing the impact of the proposed rules and amendments on small entities. However, several of the comments related to burdens that would be placed on all companies affected by the proposals. In particular, commenters believed that the proposal to require the use of different prices for disclosure and accounting purposes would impose a significant burden on all oil and gas companies. We have considered those comments and are adopting amendments to our disclosure rules and the full cost accounting method that will require the use of a single price for both purposes. Similarly, commenters were concerned that certain aspects of

[338] 15 U.S.C. 77b(b).

[339] 15 U.S.C. 78c(f).

[340] 15 U.S.C. 78w(a)(2).

[341] 5 U.S.C. 603.

[342] See Release No. 33–8870 (Dec. 12, 2007) [72 FR 71610].

the proposal, such as the new definition of geographic area and disclosure by accumulation type would increase the detail in the disclosures significantly. We agree with those commenters and have significantly reduced the level of detail required in the disclosure requirements.

C. Small Entities Subject to the New Rules and Amendments

The new rules and amendments affect small entities that are engaged in oil and gas producing activities, the securities of which are registered under Section 12 of the Exchange Act or that are required to file reports under Section 15(d) of the Exchange Act. The new rules and amendments also would affect small entities that file, or have filed, a registration statement that has not yet become effective under the Securities Act and that has not been withdrawn. Securities Act Rule 157 [343] and Exchange Act Rule 0–10(a) [344] define an issuer to be a ''small business'' or ''small organization'' for purposes of the Regulatory Flexibility Act if it had total assets of $5 million or less on the last day of its most recent fiscal year. The new rules and amendments affect small entities that are operating companies and engage in oil and gas producing activities. Based on filings in 2007, we estimate that there are approximately 28 oil and gas companies that may be considered small entities.

D. Reporting, Recordkeeping, and Other Compliance Requirements

The new rules and amendments to Regulation S–K expand some existing disclosures, and eliminate others. In particular, the new disclosure requirements, many of which were requested by industry participants, include the following:

• Disclosure of reserves from non-traditional sources (*e.g.*, bitumen and shale) as oil and gas reserves;
• Optional disclosure of probable and possible reserves;
• Optional disclosure of oil and gas reserves' sensitivity to price;
• Disclosure of the development of proved undeveloped reserves, including those that are held for 5 years or more and an explanation of why they should continue to be considered proved;
• Disclosure of technologies used to establish reserves in a company's initial filing with the Commission and in filings which include material additions to reserves estimates;
• Disclosure of the company's internal controls over reserves estimates and the qualifications the technical person primarily responsible for overseeing the preparation or audit of the reserves estimates;
• If a company represents that disclosure is based on the authority of a third party that prepared the reserves estimates or conducted a reserves audit or process review, filing a report prepared by the third party; and
• Disclosure based on a new definition of the term ''by geographic area.''

There would be no mandatory retention period for the information disclosed, and the information disclosed would be made publicly available on the EDGAR filing system.

E. Agency Action To Minimize Effect on Small Entities

We considered different compliance standards for the small entities that will be affected by the new rules and amendments. In the Proposing Release, we solicited comment regarding the possibility of different standards for small entities. We did not receive comment on this particular issue. However, we believe that such differences would be inconsistent with the purposes of the rules.

The new rules and amendments are designed to modernize the disclosure requirements for oil and gas companies. As such, we believe all oil and gas companies will benefit from the modernization of the rules. Under the new rules and amendments, all companies will be allowed to use modern technologies to establish reserves and include operations in unconventional resources in their oil and gas reserves estimates. Adopting differing standards for disclosure for small entities would significantly reduce the comparability between companies. However, the new rules and amendments do permit companies to disclose probable and possible reserves. We believe the removal of the prohibition against such reserves will enable companies to disclose a broader view of their prospects. We believe this will particularly benefit smaller oil and gas companies that may have significant unproved reserves in their portfolio. Such disclosure may assist smaller companies in raising capital for development projects in those properties.

XIV. Update to Codification of Financial Reporting Policies

The Commission amends the ''Codification of Financial Reporting Policies'' announced in Financial Reporting Release No. 1 (April 15, 1982) [47 FR 21028] as follows:

1. By removing the seven introductory paragraphs before Section 406.01, the last sentence of Section 406.01.c.vi., the first paragraph of Section 406.01.d, the introductory paragraph of Section 406.02.d, and removing and reserving Sections 406.01.a., 406.02.a, 406.02.b., 406.02.d.iii., and 406.02.e.

2. By revising Section 406.01B to read as follows:

The rules in Rule 4–10(b) specify that the application of successful efforts shall comply with SFAS 19. In 2008, the Commission published amendments to the definitions in Rule 4–10(a) that may not align completely with SFAS 19's existing terminology and application. Further, paragraph 7 of SFAS 25 states: ''For purposes of applying this Statement and Statement 19, the definition of proved reserves, proved developed reserves, and proved undeveloped reserves shall be the definitions adopted by the SEC for its reporting purposes that are in effect on the date(s) as of which the reserve disclosures are to be made. Previous reported quantities shall not be revised retroactively if the SEC definitions are changed.'' In any case, the Commission expects the practical application of SFAS 19 will remain unchanged other than incorporating the effects of the new definitions.

3. By removing the first three sentences of Section 406.02.c. and in the fourth sentence replacing the phrase ''this sort of information'' with ''information to assess the impact of oil and gas producing activities on near term cash flows and liquidity''.

4. By adding a new Section 406.03 entitled ''Transition'' and including the text of the 3rd paragraph of Section VII.B and the last sentence of the 2nd paragraph of Section VII.C of this release.

5. By adding a new Section 406.04 entitled ''MD&A Guidance'' and including the text beginning with the last sentence of the 2nd paragraph of Section V of this release through the end of that Section.

The Codification is a separate publication of the Commission. It will not be published in the **Federal Register** or Code of Federal Regulations. For more information on the Codification of Financial Reporting Policies, contact the Commission's Public Reference Room at 202–551–5850.

XV. Statutory Basis and Text of Amendments

We are adopting the amendments pursuant to Sections 3(b), 6, 7, 10 and 19(a) of the Securities Act and Sections 12, 13, 14(a), 15(d), and 23(a) of the Exchange Act, as amended.

[343] 17 CFR 230.157.

[344] 17 CFR 240.0–10(a).

Text of Amendments

List of Subjects

17 CFR Part 210

Accountants, Accounting, Reporting and recordkeeping requirements, Securities.

17 CFR Parts 211, 229 and 249

Reporting and recordkeeping requirements, Securities.

■ For the reasons set out in the preamble, title 17, chapter II of the Code of Federal Regulations is amended as follows:

PART 210—FORM AND CONTENT OF AND REQUIREMENTS FOR FINANCIAL STATEMENTS, SECURITIES ACT OF 1933, SECURITIES EXCHANGE ACT OF 1934, PUBLIC UTILITY HOLDING COMPANY ACT OF 1935, INVESTMENT COMPANY ACT OF 1940, INVESTMENT ADVISERS ACT OF 1940, AND ENERGY POLICY AND CONSERVATION ACT OF 1975

■ 1. The authority citation for part 210 continues to read as follows:

Authority: 15 U.S.C. 77f, 77g, 77h, 77j, 77s, 77z–2, 77z–3, 77aa(25), 77aa(26), 78c, 78j–1, 78*l*, 78m, 78n, 78o(d), 78q, 78u–5, 78w(a), 78*ll*, 78mm, 80a–8, 80a–20, 80a–29, 80a–30, 80a–31, 80a–37(a), 80b–3, 80b–11, 7202 and 7262, unless otherwise noted.

■ 2. Amend § 210.4–10 by:

■ a. Redesignating the subparagraphs in paragraph (a) as follows:

Old paragraph number	New paragraph number
(a)(1)	(a)(16)
(a)(2)	(a)(22)
(a)(5)	(a)(23)
(a)(6)	(a)(32)
(a)(7)	(a)(21)
(a)(8)	(a)(15)
(a)(9)	(a)(27)
(a)(10)	(a)(13)
(a)(11)	(a)(9)
(a)(12)	(a)(29)
(a)(13)	(a)(30)
(a)(14)	(a)(1)
(a)(15)	(a)(12)
(a)(16)	(a)(7)
(a)(17)	(a)(20)

■ b. Removing paragraphs (a)(3) and (a)(4);

■ c. Adding new paragraphs (a)(2), (a)(3), (a)(4), (a)(5), (a)(6), (a)(8), (a)(10), (a)(11), (a)(14), (a)(17), (a)(18), (a)(19), (a)(24), (a)(25), (a)(26), (a)(28), (a)(31), and (c)(8);

■ d. Revising newly redesignated paragraphs (a)(13), (a)(16), (a)(22), and (a)(30); and

■ e. Removing the authority citations following the section.

The additions and revisions read as follows:

§ 210.4–10 Financial accounting and reporting for oil and gas producing activities pursuant to the Federal securities laws and the Energy Policy and Conservation Act of 1975.

* * * * *

(a) Definitions. * * *

* * * * *

(2) *Analogous reservoir.* Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an ''analogous reservoir'' refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);

(ii) Same environment of deposition;

(iii) Similar geological structure; and

(iv) Same drive mechanism.

Instruction to paragraph (a)(2): Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen.* Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate.* Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate.* The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves.* Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

* * * * *

(8) *Development project.* A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

* * * * *

(10) *Economically producible.* The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR).* Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

* * * * *

(13) *Exploratory well.* An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well.* An extension well is a well drilled to extend the limits of a known reservoir.

* * * * *

(16) *Oil and gas producing activities.* (i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas (''oil and gas'') in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;

(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:

(*1*) Lifting the oil and gas to the surface; and

(*2*) Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

Instruction 1 to paragraph (a)(16)(i): The oil and gas production function shall be regarded as ending at a ''terminal point'', which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and

b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

Instruction 2 to paragraph (a)(16)(i): For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;

(B) Processing of produced oil, gas or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;

(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or

(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

* * * * *

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and

(B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

* * * * *

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

Note to paragraph (a)(26): Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (*i.e.*, absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (*i.e.*, potentially recoverable resources from undiscovered accumulations).

* * * * *

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

* * * * *

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as ''exploratory type'' if not drilled in a known area or ''development type'' if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

* * * * *

(c) * * *

(8) For purposes of this paragraph (c), the term ''current price'' shall mean the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

* * * * *

PART 211—INTERPRETATIONS RELATING TO FINANCIAL REPORTING MATTERS

■ 3. Amend Part 211, subpart A, by adding ''Modernization of Oil and Gas Reporting,'' Release No. FR–78 and the release date of December 31, 2008, to the list of interpretive releases.

PART 229—STANDARD INSTRUCTIONS FOR FILING FORMS UNDER SECURITIES ACT OF 1933, SECURITIES EXCHANGE ACT OF 1934 AND ENERGY POLICY AND CONSERVATION ACT OF 1975—REGULATION S–K

■ 4. The authority citation for part 229 continues to read in part as follows:

Authority: 15 U.S.C. 77e, 77f, 77g, 77h, 77j, 77k, 77s, 77z–2, 77z–3, 77aa(25), 77aa(26), 77ddd, 77eee, 77ggg, 77hhh, 77iii, 77jjj, 77nnn, 77sss, 78c, 78i, 78j, 78*l*, 78m, 78n, 78o, 78u–5, 78w, 78*ll*, 78mm, 80a–8, 80a–9, 80a–20, 80a–29, 80a–30, 80a–31(c), 80a–37, 80a–38(a), 80a–39, 80b–11, and 7201 *et seq.*; and 18 U.S.C. 1350, unless otherwise noted.

* * * * *

■ 5. Amend § 229.102 by revising the introductory text of Instruction 3 and Instructions 4, 5 and 8 to read as follows:

§ 229.102 (Item 102) Description of property.

* * * * *

Instructions to Item 102: * * *

3. In the case of an extractive enterprise, not involved in oil and gas producing activities, material information shall be given as to production, reserves, locations, development, and the nature of the registrant's interest. If individual properties are of major significance to an industry segment:

* * * * *

4. A registrant engaged in oil and gas producing activities shall provide the information required by Subpart 1200 of Regulation S–K.

5. In the case of extractive reserves other than oil and gas reserves, estimates other than proven or probable reserves (and any estimated values of such reserves) shall not be disclosed in any document publicly filed with the Commission, unless such information is required to be disclosed in the document by foreign or state law; provided, however, that where such estimates previously have been provided to a person (or any of its affiliates) that is offering to acquire, merge, or consolidate with the registrant, or otherwise to acquire the registrant's securities, such estimates may be included in documents relating to such acquisition.

* * * * *

8. The attention of certain issuers engaged in oil and gas producing activities is directed to the information called for in Securities Act Industry Guide 4 (referred to in § 229.801(d)).

* * * * *

■ 6. Amend § 229.801 by removing and reserving paragraph (b) and removing the authority citation following the section.

■ 7. Amend § 229.802 by removing and reserving paragraph (b) and removing the authority citation following the section.

■ 8. Add Subpart 229.1200 to read as follows:

Subpart 229.1200—Disclosure by Registrants Engaged in Oil and Gas Producing Activities

Sec.
229.1201 (Item 1201) General instructions to oil and gas industry-specific disclosures.
229.1202 (Item 1202) Disclosure of reserves.
229.1203 (Item 1203) Proved undeveloped reserves.
229.1204 (Item 1204) Oil and gas production, production prices and production costs.
229.1205 (Item 1205) Drilling and other exploratory and development activities.
229.1206 (Item 1206) Present activities.
229.1207 (Item 1207) Delivery commitments.
229.1208 (Item 1208) Oil and gas properties, wells, operations, and acreage.

Subpart 229.1200—Disclosure by Registrants Engaged in Oil and Gas Producing Activities

§ 229.1201 (Item 1201) General instructions to oil and gas industry-specific disclosures.

(a) If oil and gas producing activities are material to the registrant's or its subsidiaries' business operations or financial position, the disclosure specified in this Subpart 229.1200 should be included under appropriate captions (with cross references, where applicable, to related information disclosed in financial statements). However, limited partnerships and joint ventures that conduct, operate, manage, or report upon oil and gas drilling or income programs, that acquire properties either for drilling and production, or for production of oil, gas, or geothermal steam or water, need not include such disclosure.

(b) To the extent that Items 1202 through 1208 (§§ 229.1202–229.1208) call for disclosures in tabular format, as specified in the particular Item, a registrant may modify such format for ease of presentation, to add information or to combine two or more required tables.

(c) The definitions in Rule 4–10(a) of Regulation S–X (17 CFR 210.4–10(a)) shall apply for purposes of this Subpart 229.1200.

(d) For purposes of this Subpart 229.1200, the term *by geographic area* means, as appropriate for meaningful disclosure in the circumstances:

(1) By individual country;

(2) By groups of countries within a continent; or

(3) By continent.

§ 229.1202 (Item 1202) Disclosure of reserves.

(a) *Summary of oil and gas reserves at fiscal year end.* (1) Provide the information specified in paragraph (a)(2) of this Item in tabular format as provided below:

SUMMARY OF OIL AND GAS RESERVES AS OF FISCAL-YEAR END BASED ON AVERAGE FISCAL-YEAR PRICES

Reserves category	Reserves				
	Oil (mbbls)	Natural gas (mmcf)	Synthetic oil (mbbls)	Synthetic gas (mmcf)	Product A (measure)
PROVED	....	....	....	....	....
Developed:	....	....	....	....	....
Continent A	....	....	....	....	....
Continent B	....	....	....	....	....
Country A	....	....	....	....	....
Country B	....	....	....	....	....
Other Countries in Continent B	....	....	....	....	....
Undeveloped:	....	....	....	....	....
Continent A	....	....	....	....	....
Continent B	....	....	....	....	....

SUMMARY OF OIL AND GAS RESERVES AS OF FISCAL-YEAR END BASED ON AVERAGE FISCAL-YEAR PRICES—Continued

Reserves category	Reserves				
	Oil (mbbls)	Natural gas (mmcf)	Synthetic oil (mbbls)	Synthetic gas (mmcf)	Product A (measure)
Country A					
Country B					
Other Countries in Continent B					
TOTAL PROVED					
PROBABLE					
Developed					
Undeveloped					
POSSIBLE					
Developed					
Undeveloped					

(2) Disclose, in the aggregate and by geographic area and for each country containing 15% or more of the registrant's proved reserves, expressed on an oil-equivalent-barrels basis, reserves estimated using prices and costs under existing economic conditions, for the product types listed in paragraph (a)(4) of this Item, in the following categories:

(i) Proved developed reserves;

(ii) Proved undeveloped reserves;

(iii) Total proved reserves;

(iv) Probable developed reserves (optional);

(v) Probable undeveloped reserves (optional);

(vi) Possible developed reserves (optional); and

(vii) Possible undeveloped reserves (optional).

Instruction 1 to paragraph (a)(2): Disclose updated reserves tables as of the close of each fiscal year.

Instruction 2 to paragraph (a)(2): The registrant is permitted, but not required, to disclose probable or possible reserves pursuant to paragraphs (a)(2)(iv) through (a)(2)(vii) of this Item.

Instruction 3 to paragraph (a)(2): If the registrant discloses amounts of a product in barrels of oil equivalent, disclose the basis for such equivalency.

Instruction 4 to paragraph (a)(2): A registrant need not provide disclosure of the reserves in a country containing 15% or more of the registrant's proved reserves if that country's government prohibits disclosure of reserves in that country. In addition, a registrant need not provide disclosure of the reserves in a country containing 15% or more of the registrant's proved reserves if that country's government prohibits disclosure in a particular field and disclosure of reserves in that country would have the effect of disclosing reserves in particular fields.

(3) Reported total reserves shall be simple arithmetic sums of all estimates for individual properties or fields within each reserves category. When probabilistic methods are used, reserves should not be aggregated probabilistically beyond the field or property level; instead, they should be aggregated by simple arithmetic summation.

(4) Disclose separately material reserves of the following product types:

(i) Oil;

(ii) Natural gas;

(iii) Synthetic oil;

(iv) Synthetic gas; and

(v) Sales products of other non-renewable natural resources that are intended to be upgraded into synthetic oil and gas.

(5) If the registrant discloses probable or possible reserves, discuss the uncertainty related to such reserves estimates.

(6) If the registrant has not previously disclosed reserves estimates in a filing with the Commission or is disclosing material additions to its reserves estimates, the registrant shall provide a general discussion of the technologies used to establish the appropriate level of certainty for reserves estimates from material properties included in the total reserves disclosed. The particular properties do not need to be identified.

(7) *Preparation of reserves estimates or reserves audit.* Disclose and describe the internal controls the registrant uses in its reserves estimation effort. In addition, disclose the qualifications of the technical person primarily responsible for overseeing the preparation of the reserves estimates and, if the registrant represents that a third party conducted a reserves audit, disclose the qualifications of the technical person primarily responsible for overseeing such reserves audit.

(8) *Third party reports.* If the registrant represents that a third party prepared, or conducted a reserves audit of, the registrant's reserves estimates, or any estimated valuation thereof, or conducted a process review, the registrant shall file a report of the third party as an exhibit to the relevant registration statement or other Commission filing. If the report relates to the preparation of, or a reserves audit of, the registrant's reserves estimates, it must include the following disclosure, if applicable to the type of filing:

(i) The purpose for which the report was prepared and for whom it was prepared;

(ii) The effective date of the report and the date on which the report was completed;

(iii) The proportion of the registrant's total reserves covered by the report and the geographic area in which the covered reserves are located;

(iv) The assumptions, data, methods, and procedures used, including the percentage of the registrant's total reserves reviewed in connection with the preparation of the report, and a statement that such assumptions, data, methods, and procedures are appropriate for the purpose served by the report;

(v) A discussion of primary economic assumptions;

(vi) A discussion of the possible effects of regulation on the ability of the registrant to recover the estimated reserves;

(vii) A discussion regarding the inherent uncertainties of reserves estimates;

(viii) A statement that the third party has used all methods and procedures as it considered necessary under the circumstances to prepare the report;

(ix) A brief summary of the third party's conclusions with respect to the reserves estimates; and

(x) The signature of the third party.

(9) For purposes of this Item 1202, the term *reserves audit* means the process of reviewing certain of the pertinent facts interpreted and assumptions underlying a reserves estimate prepared by another party and the rendering of an opinion about the appropriateness of the methodologies employed, the adequacy and quality of the data relied upon, the depth and thoroughness of the reserves estimation process, the classification of reserves appropriate to the relevant definitions used, and the reasonableness of the estimated reserves quantities.

(b) *Reserves sensitivity analysis (optional).* (1) The registrant may, but is not required to, provide the information specified in paragraph (b)(2) of this Item in tabular format as provided below:

SENSITIVITY OF RESERVES TO PRICES BY PRINCIPAL PRODUCT TYPE AND PRICE SCENARIO

Price case	Proved reserves					Probable reserves					Possible reserves				
	Oil	Gas	Syn. oil	Syn. gas	Product A	Oil	Gas	Syn. oil	Syn. gas	Product A	Oil	Gas	Syn. oil	Syn. gas	Product A
	mbbls	mmcf	mbbls	mmcf	measure	mbbls	mmcf	mbbls	mmcf	measure	mbbls	mmcf	mbbls	mmcf	measure
Scenario 1.															
Scenario 2.															

(2) The registrant may, but is not required to, disclose, in the aggregate, an estimate of reserves estimated for each product type based on different price and cost criteria, such as a range of prices and costs that may reasonably be achieved, including standardized futures prices or management's own forecasts.

(3) If the registrant provides disclosure under this paragraph (b), disclose the price and cost schedules and assumptions on which the disclosed values are based.

Instruction to Item 1202: Estimates of oil or gas resources other than reserves, and any estimated values of such resources, shall not be disclosed in any document publicly filed with the Commission, unless such information is required to be disclosed in the document by foreign or state law; provided, however, that where such estimates previously have been provided to a person (or any of its affiliates) that is offering to acquire, merge, or consolidate with the registrant or otherwise to acquire the registrant's securities, such estimate may be included in documents related to such acquisition.

§ 229.1203 (Item 1203) Proved undeveloped reserves.

(a) Disclose the total quantity of proved undeveloped reserves at year end.

(b) Disclose material changes in proved undeveloped reserves that occurred during the year, including proved undeveloped reserves converted into proved developed reserves.

(c) Discuss investments and progress made during the year to convert proved undeveloped reserves to proved developed reserves, including, but not limited to, capital expenditures.

(d) Explain the reasons why material amounts of proved undeveloped reserves in individual fields or countries remain undeveloped for five years or more after disclosure as proved undeveloped reserves.

§ 229.1204 (Item 1204) Oil and gas production, production prices and production costs.

(a) For each of the last three fiscal years disclose production, by final product sold, of oil, gas, and other products. Disclosure shall be made by geographical area and for each country and field that contains 15% or more of the registrant's total proved reserves expressed on an oil-equivalent-barrels basis unless prohibited by the country in which the reserves are located.

(b) For each of the last three fiscal years disclose, by geographical area:

(1) The average sales price (including transfers) per unit of oil, gas and other products produced; and

(2) The average production cost, not including ad valorem and severance taxes, per unit of production.

Instruction 1 to Item 1204: Generally, net production should include only production that is owned by the registrant and produced to its interest, less royalties and production due others. However, in special situations (*e.g.*, foreign production) net production before any royalties may be provided, if more appropriate. If ''net before royalty'' production figures are furnished, the change from the usage of ''net production'' should be noted.

Instruction 2 to Item 1204: Production of natural gas should include only marketable production of natural gas on an ''as sold'' basis. Production will include dry, residue, and wet gas, depending on whether liquids have been extracted before the registrant transfers title. Flared gas, injected gas, and gas consumed in operations should be omitted. Recovered gas-lift gas and reproduced gas should not be included until sold. Synthetic gas, when marketed as such, should be included in natural gas sales.

Instruction 3 to Item 1204: If any product, such as bitumen, is sold or custody is transferred prior to conversion to synthetic oil or gas, the product's production, transfer prices, and production costs should be disclosed separately from all other products.

Instruction 4 to Item 1204: The transfer price of oil and gas (natural and synthetic) produced should be determined in accordance with SFAS 69.

Instruction 5 to Item 1204: The average production cost, not including ad valorem and severance taxes, per unit of production should be computed using production costs disclosed pursuant to SFAS 69. Units of production should be expressed in common units of production with oil, gas, and other products converted to a common unit of measure on the basis used in computing amortization.

§ 229.1205 (Item 1205) Drilling and other exploratory and development activities.

(a) For each of the last three fiscal years, by geographical area, disclose:

(1) The number of net productive and dry exploratory wells drilled; and

(2) The number of net productive and dry development wells drilled.

(b) *Definitions.* For purposes of this Item 1205, the following terms shall be defined as follows:

(1) A *dry well* is an exploratory, development, or extension well that proves to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

(2) A *productive well* is an exploratory, development, or extension well that is not a dry well.

(3) *Completion* refers to installation of permanent equipment for production of oil or gas, or, in the case of a dry well, to reporting to the appropriate authority that the well has been abandoned.

(4) The *number of wells drilled* refers to the number of wells completed at any time during the fiscal year, regardless of when drilling was initiated.

(c) Disclose, by geographic area, for each of the last three years, any other exploratory or development activities conducted, including implementation of mining methods for purposes of oil and gas producing activities.

§ 229.1206 (Item 1206) Present activities.

(a) Disclose, by geographical area, the registrant's present activities, such as the number of wells in the process of being drilled (including wells temporarily suspended), waterfloods in process of being installed, pressure maintenance operations, and any other related activities of material importance.

(b) Provide the description of present activities as of a date at the end of the most recent fiscal year or as close to the date that the registrant files the document as reasonably possible.

(c) Include only those wells in the process of being drilled at the ''as of'' date and express them in terms of both gross and net wells.

(d) Do not include wells that the registrant plans to drill, but has not commenced drilling unless there are factors that make such information material.

§ 229.1207 (Item 1207) Delivery commitments.

(a) If the registrant is committed to provide a fixed and determinable quantity of oil or gas in the near future under existing contracts or agreements, disclose material information concerning the estimated availability of oil and gas from any principal sources, including the following:

(1) The principal sources of oil and gas that the registrant will rely upon and the total amounts that the registrant expects to receive from each principal source and from all sources combined;

(2) The total quantities of oil and gas that are subject to delivery commitments; and

(3) The steps that the registrant has taken to ensure that available reserves and supplies are sufficient to meet such commitments for the next one to three years.

(b) Disclose the information required by this Item:

(1) In a form understandable to investors; and

(2) Based upon the facts and circumstances of the particular situation, including, but not limited to:

(i) Disclosure by geographic area;

(ii) Significant supplies dedicated or contracted to the registrant;

(iii) Any significant reserves or supplies subject to priorities or curtailments which may affect quantities delivered to certain classes of customers, such as customers receiving services under low priority and interruptible contracts;

(iv) Any priority allocations or price limitations imposed by Federal or State regulatory agencies, as well as other factors beyond the registrant's control that may affect the registrant's ability to meet its contractual obligations (the registrant need not provide detailed discussions of price regulation);

(v) Any other factors beyond the registrant's control, such as other parties having control over drilling new wells, competition for the acquisition of reserves and supplies, and the availability of foreign reserves and supplies, which may affect the registrant's ability to acquire additional reserves and supplies or to maintain or increase the availability of reserves and supplies; and

(vi) Any impact on the registrant's earnings and financing needs resulting from its inability to meet short-term or long-term contractual obligations. (See Items 303 and 1209 of Regulation S–K (§§ 229.303 and 229.1209).)

(c) If the registrant has been unable to meet any significant delivery commitments in the last three years, describe the circumstances concerning such events and their impact on the registrant.

(d) For purposes of this Item, *available reserves* are estimates of the amounts of oil and gas which the registrant can produce from current proved developed reserves using presently installed equipment under existing economic and operating conditions and an estimate of amounts that others can deliver to the registrant under long-term contracts or agreements on a per-day, per-month, or per-year basis.

§ 229.1208 (Item 1208) Oil and gas properties, wells, operations, and acreage.

(a) Disclose, as of a reasonably current date or as of the end of the fiscal year, the total gross and net productive wells, expressed separately for oil and gas (including synthetic oil and gas produced through wells) and the total gross and net developed acreage (*i.e.*, acreage assignable to productive wells) by geographic area.

(b) Disclose, as of a reasonably current date or as of the end of the fiscal year, the amount of undeveloped acreage, both leases and concessions, if any, expressed in both gross and net acres by geographic area, together with an indication of acreage concentrations, and, if material, the minimum remaining terms of leases and concessions.

(c) *Definitions.* For purposes of this Item 1208, the following terms shall be defined as indicated:

(1) A *gross well or acre* is a well or acre in which the registrant owns a working interest. The number of gross wells is the total number of wells in which the registrant owns a working interest. Count one or more completions in the same bore hole as one well. In a footnote, disclose the number of wells with multiple completions. If one of the multiple completions in a well is an oil completion, classify the well as an oil well.

(2) A *net well or acre* is deemed to exist when the sum of fractional ownership working interests in gross wells or acres equals one. The number of net wells or acres is the sum of the fractional working interests owned in gross wells or acres expressed as whole numbers and fractions of whole numbers.

(3) *Productive wells* include producing wells and wells mechanically capable of production.

(4) *Undeveloped acreage* encompasses those leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas regardless of whether such acreage contains proved reserves. Do not confuse undeveloped acreage with undrilled acreage held by production under the terms of the lease.

PART 249—FORMS, SECURITIES EXCHANGE ACT OF 1934

■ 9. The authority citation for part 249 continues to read in part as follows:

Authority: 15 U.S.C. 78a *et seq.* and 7201; and 18 U.S.C. 1350, unless otherwise noted.

* * * * *

■ 10. Amend Form 20–F (referenced in § 249.220f) by:

■ a. Revising ''Instruction to Item 4'' and the introductory text and paragraph (b) of ''Instructions to Item 4.D''; and

■ b. Removing paragraph (c) of ''Instructions to Item 4.D'' and ''Appendix A to Item 4.D—Oil and Gas.''

The revisions read as follows:

[**Note:** The text of Form 20–F does not, and this amendment will not, appear in the Code of Federal Regulations.]

Form 20–F

* * * * *

Item 4. Information on the Company

* * * * *

Instructions to Item 4

1. Furnish the information specified in any industry guide listed in Subpart 229.800 of Regulation S–K (§ 229.801 *et seq.* of this chapter) that applies to you.

2. If oil and gas operations are material to you or your subsidiaries' business operations or financial position, provide the information specified in Subpart 1200 of Regulation S–K (§ 229.1200 *et seq.* of this chapter).

* * * * *

Instruction to Item 4.D: In the case of an extractive enterprise, other than an oil and gas producing activity:

* * * * *

(b) In documents that you file publicly with the Commission, do not disclose estimates of reserves unless the reserves are proven or probable and do not give estimated values of those reserves, unless foreign law requires you to disclose the information. If these types of estimates have already been provided to any person that is offering to acquire you, however, you may include the estimates in documents relating to the acquisition.

* * * * *

Dated: December 31, 2008.

By the Commission.

Florence E. Harmon,

Acting Secretary.

[FR Doc. E9–409 Filed 1–13–09; 8:45 am]

BILLING CODE 8011–01–P

Subject: Cabot #2 Well
From: David Kovach <David.Kovach@drbc.state.nj.us>
Date: Tue, 04 Aug 2009 17:05:30 -0400
To: jimmy@arbor-resources.com

Dear Mr. Eichstadt,
I am writing concerning the application for the Cabot #2 well submitted to the Commission by Arbor Operating, LLC (Arbor) on April 16, 2009. As you are aware, on May 19, 2009, the Executive Director of the DRBC issued a determination concerning proposed and existing natural gas wells and associated appurtenances completed in the Marcellus Shale and other shale formations in the drainage area of Special Protection Waters in the Delaware River Basin. As the Cabot #2 natural gas well that Arbor has proposed lies within the drainage area to the special protection waters known as the Lower Delaware and is proposed to be drilled into a shale formation, it is covered under the Executive Director determination. As Arbor has stated that they propose to develop the well if a viable quantity of natural gas is discovered, the well is not therefore being drilled solely for exploratory purposes and is again covered under the Executive Directors Determination. The well may not be covered under the determination if a cap and plug plan is submitted to the Commission and it is affirmed that the well will be properly abandoned upon completion and collection of necessary exploratory data. The groundwater withdrawal rate of significantly less than 100,000 gpd during any consecutive 30-day period detailed in the application is not specifically covered by DRBC regulations, but all water supplies, no matter what the withdrawal volume, will be considered from a potential impact/interference standpoint when an application for a natural gas well in Marcellus or other shale proposed in special protection waters is being reviewed.

The application for the Cabot #2 well as submitted requires additional information if natural gas development at the well is to be considered for DRBC approval. These include, but are not necessarily limited to the following:

1) A revised applicant statement and appropriate fee, related to the actual total project costs that would include the drilling and construction of the Cabot #2 well.

2) The necessary information included in the attached draft natural gas project submission requirements word document.

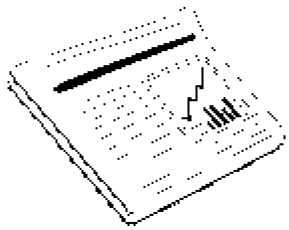
If the well will be used solely for exploratory purposes, then an appropriate cap and plug plan must be submitted to the Commission affirming that the well will be properly abandoned upon completion and collection of necessary scientific data.

Please contact me if you have any further questions,
Dave

--
David Kovach, P.G.
Geologist, Project Review Section
Delaware River Basin Commission
(p) 609-883-9500 ext 264
(f) 609-883-9522
(e) david.kovach@drbc.state.nj.us

Shale gas drilling project submission requirements.doc	**Content-Type:** application/msword **Content-Encoding:** base64

Delaware River Basin Commission



News Release

For Immediate Release

May 19, 2009

DRBC ELIMINATES REVIEW THRESHOLDS FOR GAS EXTRACTION PROJECTS IN SHALE FORMATIONS IN DELAWARE BASIN'S SPECIAL PROTECTION WATERS

(WEST TRENTON, N.J.) -- Delaware River Basin Commission (DRBC) Executive Director Carol R. Collier today announced that she has issued a determination notifying natural gas extraction project sponsors that they may not commence any natural gas extraction project located in shale formations within the drainage area of the basin’s Special Protection Waters without first applying for and obtaining commission approval.

“This determination explains DRBC regulatory requirements on an interim basis and asserts commission review over all aspects of natural gas extraction projects in shale formations within the drainage area of the basin’s Special Protection Waters, regardless of the amount of water withdrawn or the capacity of domestic sewage treatment facilities accepting fracking wastewater,” Collier said. “The commissioners intend to adopt regulations pertaining to the subject matter contained in this determination after public notice and a full opportunity for public comment, but this rulemaking process can be lengthy. In the meantime, DRBC will apply this determination in combination with its existing regulations.”

In taking this action, Collier considered and determined that as a result of water withdrawals, wastewater disposal, and other activities, natural gas extraction projects in shale formations may individually or cumulatively affect the water quality of Special Protection Waters by altering their physical, biological, chemical or hydrological characteristics. This finding is in accordance with Section 2.3.5 B.18 of the commission’s Rules of Practice and Procedure, which provide that any project “that the Executive Director may specially direct by notice to the project sponsor or land owner as having a potential substantial water quality impact on waters classified as Special Protection Waters” may be required to undergo review.

“The intent behind this executive director determination is to provide directional signals, not put up roadblocks,” Collier said. “Each of these activities, if not properly performed, may cause adverse environmental effects on water resources. The bottom line for the DRBC is to ensure that proper environmental controls are provided to safeguard our basin's water resources that are used by nearly 15 million people.”

Most of the shale formations that may be subject to new horizontal drilling and hydraulic fracturing techniques requiring large volumes of water in the basin are located within the drainage area to DRBC’s designated Special Protection Waters (SPW). The commission’s SPW program is designed to prevent degradation in streams and rivers considered to have exceptionally high scenic, recreational, ecological, and/or water supply values through stricter control of wastewater discharges, non-point pollution control, and reporting requirements. Coverage of the DRBC’s SPW anti-degradation regulations includes the 197-mile non-tidal Delaware River from Hancock, N.Y. south to Trenton, N.J. and the land draining to this stretch.

Under this determination, a natural gas extraction project encompasses the drilling pad upon which a well intended for eventual production is located, all accompanying facilities and related activities, and all locations of water withdrawals used or to be used to supply water to the project. Wells intended solely for exploratory purposes are not covered by this determination. An exploratory well is one that the project sponsor intends to plug and cap at the conclusion of exploratory activities without use for production or fracking. Exploratory wells are subject to state regulation.

“To determine whether the Rules of Practice and Procedure require DRBC review of any projects falling outside this determination, we continue to recommend that any company proposing natural gas extraction activities anywhere in the basin contact DRBC staff to schedule a pre-application meeting,” Collier said.

The DRBC recognizes that each natural gas extraction project also will be subject to the review of the environmental agency of the state in which the project is located and, in some cases, subject to federal agency review. The commission intends to coordinate with and, where feasible, to utilize the review process and approvals of the applicable state or federal agency to minimize duplication of effort and redundant requirements imposed on project sponsors.

Any person adversely affected by this determination may request a hearing by submitting a request in writing to the commission secretary within 30 days of the date of this determination in accordance with the DRBC’s Rules of Practice and Procedure.

The DRBC was formed by compact in 1961 through legislation signed into law by President John F. Kennedy and the governors of the four basin states with land draining to the Delaware River (Delaware, New Jersey, New York, and Pennsylvania). The passage of this compact marked the first time in our nation’s history that the federal government and a group of states joined together as equal partners in a river basin planning, development, and regulatory agency.

Additional information, including the complete determination, can be found by clicking here.

COMMONWEALTH OF PENNSYLVANIA
Department of Environmental Protection

Guidelines for the Development and Implementation of Environmental Emergency Response Plans

400-2200-001

PA Department of Environmental Protection
PO Box 2063
Harrisburg, PA 17105-2063

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

DOCUMENT ID:	400-2200-001
TITLE:	Guidelines for the Development and Implementation of Environmental Emergency Response Plans
EFFECTIVE DATE:	April 2001 Minor changes were made throughout the document on September 7, 2004 Minor changes were made throughout the document on August 6, 2005
AUTHORITY	The Federal Clean Water Act, the Pennsylvania Clean Streams Law (35 P.S. §§691.1-691.1001), the Pennsylvania Solid Waste Management Act, the Pennsylvania Storage Tank Act, the Oil Pollution Act and regulations promulgated thereunder.
POLICY:	To plan and provide effective and efficient response to emergencies and accidents for any situation dealing with the public health, safety and the environment.
PURPOSE:	To improve and preserve the purity of the Waters of the Commonwealth by prompt adequate response to all emergencies and accidental spills of polluting substances for the protection of public health, animal and aquatic life and for recreation.
BACKGROUND:	This document is being revised to add regulatory references in Table 1 and Procedures, Item A. Revisions were made to Procedures, Items A, C, D and F. Some telephone contact names, telephone contact numbers and bureau names have been updated in Appendices IV and V. Bureau and division names have been changed on the cover page of the Addendum.
APPLICABILITY:	This document provides a one stop requirement to comply with the state and federal laws and regulations dealing with emergency planning and response and pollution prevention and contingency planning requirements (plans such as PIP, SPCC, SWPPP, etc.) for all activities to be carried out in the Commonwealth.
DISCLAIMER:	The policies and procedures outlined in this guidance are intended to supplement existing requirements. Nothing in the policies or procedures shall affect regulatory requirements. The policies and procedures herein are not an adjudication or a regulation. There is no intent on the part of DEP to give the rules in these policies that weight or deference. This document establishes the framework within which DEP will exercise its administrative discretion in the future. DEP reserves the discretion to deviate from this policy statement if circumstances warrant.
PAGE LENGTH:	48 Pages
LOCATION:	Vol. 33, Tab 56

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

Guidelines for the Development and Implementation of Environmental Emergency Response Plans

This document (400-2200-001) provides a one stop requirement to comply with the state and federal laws and regulations dealing with emergency planning and response and pollution prevention and contingency planning requirements (i.e., PIP, SPCC, SWPPP, etc) for all activities to be carried out in the Commonwealth.

The use of the document and compliance with it are required as part of applying for any permit or requesting approval of any action that has a potential to cause pollution of the Commonwealth's air, water and land resources. The manual is also available to download from the DEP website at: www.dep.state.pa.us.

The document may be revised from time to time or as the need arises due to changes in state/federal laws and regulations. If you have suggestions for improvement to this document or desire that future revisions be sent to you, please provide the following information to the Department.

Date this request made: ______________________________

Name ______________________________

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Send to: Director, Environmental Emergency Response
Pennsylvania Department of Environmental Protection
Field Operations Deputate, RCSOB 16th Floor
P.O. Box 2063
Harrisburg, PA 17105-2063

Guidelines for the Development and Implementation of Environmental Emergency Response Plans

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Guidelines for the Development and Implementation of Environmental Emergency Response Plans

INTRODUCTION

A wide variety of industrial activities, both manufacturing and commercial, exist in Pennsylvania. Many of these activities have the potential for causing environmental degradation or endangerment of public health and safety through accidental releases of toxic, hazardous, or other pollutional materials.

In recognition of this fact, several State and Federal regulatory programs have been developed to encourage the use of preventive approaches to deal with unwarranted releases of toxic, hazardous, or other pollutants to the environment.

Table 1 lists these programs and defines the statutory and regulatory basis for each. A more detailed summary of each program is shown in Table 2 which illustrates the similarities among them. A review of the regulations and guidelines pertaining to each program more clearly illustrates these similarities. The main differences between the programs are the types of industrial activities and the nature of the polluting materials addressed.

The Department's objective is to consolidate the similarities of the State and Federal pollution incident prevention and emergency response programs into one overall program. Industrial and commercial installations which have the potential for causing accidental pollution of air, land or water, or the endangerment of public health and safety are required to develop and implement **Preparedness, Prevention and Contingency (PPC) Plans** which encompass the other Departmental program requirements.

A PPC Plan is required for any NPDES Application for Storm Water Discharge General Permits or Water Management Permits. A special addendum has been added to the document for NPDES Stormwater discharge applicants.

In the case of regulated storage tank facilities, with an aggregate aboveground storage capacity > 21,000 gallons, a **Spill Prevention Response (SPR)** plan is required. This SPR plan, in **addition to the contents** of a PPC plan, requires a specific downstream notification requirement. Those storage tank facilities that already have a PPC plan need only update the PPC plan and include the downstream notification requirement.

The Department strongly recommends that regulated facilities consolidate all required plans into one single document. For those facilities required to develop plans under SARA Title III, the Department will support deviation from the format suggested in this guidance document to ensure consistency with the SARA Title III plans provided that all required information is included in the one plan.

TABLE 1
STATE AND FEDERAL POLLUTION INCIDENT
PREVENTION AND EMERGENCY RESPONSE PROGRAMS

Plan	Implemented By	State and Federal Laws Which Apply	State and Implementing Regulations	Effective Date of Regulations
Spill Prevention Control and Countermeasure (SPCC)	U.S. EPA*	Federal Clean Water Act	40 CFR 112	1973
Preparedness, Prevention, and Contingency (PPC), or Contingency Planning	Pa. DEP as part of the Hazardous Waste Program	Pa. Solid Waste Management Act	25 Pa. Code Ch. 262a, 264a, 265a, 266a	5/01/99
	Pa. DEP as part of the Residual Waste Program	Pa. Solid Waste Management Act	25 Pa. Code Ch. 287, 288, 289, 293, 295 and 297	7/4/92
	Pa. DEP as part of the Municipal Waste Program	Pa. Solid Waste Management Act	25 Pa. Code Ch. 273, 277, 279, 281, 283 and 284	4/9/88
	Pa. DEP as part of the Oil and Gas Program[1]	Pa. Clean Streams Law, Pa Solid Waste Management Act	25 Pa. Code Ch. 91.34, 25 Pa. Code Ch. 78	1971
	Pa. DEP as part of the Water Quality Program.	PA Clean Streams Law	25 PA Code Chapter 91.34	1971
	Pa. DEP and US EPA as part of the NPDES Program	Federal Clean Water Act.	40 CFR 125 Subpart K	5/19/80
Spill Prevention Response (SPR) Plan	Pa. DEP as part of the Storage Tank Program	Pa. Storage Tank and Spill Prevention Act	Act 32-1989	8/89
Facility Response Plan (FRP)	US EPA* US Coast Guard	Oil Pollution Act	40 CFR 112	1990

(1) Complete information on PPC Plans required under the Oil and Gas Program can be found in the ***Oil & Gas Operators Manual*** available from the Bureau of Oil and Gas Management.

* Additional information is available from US EPA Region III, Philadelphia, PA, (215) 814-3292.

TABLE 2
COMPARISON OF STATE AND FEDERAL POLLUTION INCIDENT PREVENTION AND EMERGENCY RESPONSE PROGRAMS

Aspect	Preparedness, Prevention, and Contingency (PPC) (Water)	Preparedness, Prevention, and Contingency (PPC) (Waste)	Spill Prevention Response (SPR) Plan	Spill Prevention Control, and Countermeasures (SPCC)
Purpose	Prevention/Control of accidental discharge of polluting materials to surface waste or groundwater	To minimize and abate hazards to human health and the environment from fires, explosions, or release of solid wastes to air, soil, or surface water	Prevention/Control of accidental discharge of regulated substances and downstream notification requirements	Prevention of accidental discharges of oils and hazardous substances into the waters of the United States
Types of Industrial Activities Affected	All industrial activities having potential for accidental pollution	Activities which generate, store, recycle, treat, transport, or dispose of solid wastes, activities associated with drilling and operating oil and gas wells	Activities pertaining to above ground storage facilities with >21,000 gallons of regulated substances	Non-transportation related activities with potential for discharge of oil and hazardous substances
Activities Covered?	Transportation, storage, processing of raw materials, intermediates, products, fuels, wastes	Generation, storage, transport, recycle, treatment, disposal of hazardous wastes; processing and disposal of residual or municipal wastes; road spreading operations, brine disposal	Storage and handling of regulated substances	Production, storage, processing, refining, handling, transferring, distributing
What Pollution Materials are Addressed?	All polluting materials	Any hazardous, residual, municipal, or medical wastes	Hazardous Substances and Petroleum	Oil and hazardous substances defined pursuant to Sec. 311 of the Clean Water Act

TABLE 2 (Cont.)
COMPARISON OF STATE AND FEDERAL POLLUTION INCIDENT PREVENTION AND EMERGENCY RESPONSE PROGRAMS

Aspect	Preparedness, Prevention, and Contingency (PPC) (Water)	Preparedness, Prevention, and Contingency (PPC) (Waste)	Spill Prevention Response (SPR) Plan	Spill Prevention Control, and Countermeasures (SPCC)
Hazards Addressed	Container leaks, ruptures, spills, floods, power failures, mechanical failure, human error, strikes, vandalism	Same plus fires and explosions	Same	Same
Plan Includes	Study of past incidents, training, preventive maintenance, housekeeping, security, backup equipment, internal, external communicator, spill containment, drainage controls, inspections	Same plus additional local notification, emergency coordination, and evacuation requirements	Same, plus downstream notification requirement	Same
Amendments to Plan Required for Significant Facility or Operational Changes?	Yes	Yes	Yes	Yes
Emergency Incident Report Required?	Yes	Yes	Yes	Yes
Annual Notifica-tion/Updated	No	No	Yes	No

I. PROCEDURES FOR DEVELOPMENT AND REVIEW OF ENVIRONMENTAL EMERGENCY RESPONSE PLANS

A. Who Must Develop These Plans?

PPC

In general, any manufacturing or commercial installation which has the potential for causing accidental pollution of air, land, or water or for causing endangerment of public health and safety through accidental release of toxic, hazardous, or other polluting materials must develop, maintain, and implement a PPC Plan.*

Manufacturing or commercial waste water dischargers, which are required to obtain NPDES permits, must develop PPC plans in order to satisfy the requirements of Chapter 101 of the Department's Rules and Regulations. In addition to NPDES discharges there are a variety of other non-NPDES manufacturing or commercial installations which may be directed by the Department to develop PPC plans on a case-by-case basis.

Manufacturing or commercial installations which generate hazardous waste, or which involve treatment, recycling, storage, or disposal of hazardous waste must develop PPC plans in conformance with Chapter 262a, 264a, and 265a of the Department's regulations. Generators, of between 100 and 1,000 kilograms of hazardous waste per month, may not be required to have a PPC plan if they comply with the Preparedness and Prevention requirements in the regulations. (Note: hazardous waste transporters must also develop PPC plans under Chapter 263a. A separate PPC guidance document has been developed for transporters.)

A person who owns or operates a residual waste disposal or processing facility must develop a PPC plan under Chapters 287, 288, 289, 293, 295, and 297 of the residual waste regulations.

A person who owns or operates a municipal waste disposal or processing facility must develop a PPC plan under Chapters 273, 277, 279, 281, 283, and 284 of the municipal waste regulations.

In regards to the Oil and Gas Program, PPC Plans are required under the Clean Streams Law for approval of road spreading operations, drilling and operating oil and gas wells, and brine disposal wells. These plans are required under 25 Pa. Code Chapters 91.34 and 78.55. In addition, PPC Plans are required for NPDES and Part II Water Quality Management Permits. The Plan requirements are contained in the Oil and Gas Operators Manual

SPR

Facility owners with aboveground storage tank aggregate capacity > 21,000 gallons of a regulated substance.

*Note: PPC plans developed by hazardous waste generators and/or treatment, recycling, storage or disposal facilities, which would not otherwise be required to obtain NPDES or Water Quality Protection Part II permits, generally need only to address the PPC planning requirements as they pertain to their hazardous waste activity (unless otherwise directed by the Department).

B. How Do Existing Emergency Response Plans Fit in With Newer Program Requirements?

It should be noted that oil-related Spill Prevention, Control, and Countermeasure (SPCC) plans, which are or have been developed pursuant to EPA's oil-related SPCC regulations, should also be considered as part of an installation's overall PPC plan. Some installations may elect to integrate their oil-related SPCC plan with the PPC or SPR plan elements, or may elect to keep it as a separate chapter, or appendix, to the PPC or SPR plan.

Likewise, the additional downstream notification requirement of an SPR plan can be added to an existing plan to satisfy the "Storage Tank and Spill Prevention Act," providing all required elements of a SPR plan are completed for the existing plan.

Other types of existing emergency response plans should be handled in a similar manner.

C. Development and Submission of Plans for Review and Approval.

The plan must be developed in accordance with good engineering practice by someone who is familiar with the day-to-day operations at the site. If an outside consultant is employed for this purpose, he must be authorized to conduct a thorough study of the material storage, handling, usage, disposal, and waste management practices conducted at the installation.

Section II outlines the general content and format of PPC and SPR plans.

In general, plans should be submitted for review and approval by the Department in conjunction with applications for NPDES Water Quality Management, Storage Tank, Residual Waste Management, Municipal Water Management, or Hazardous Waste Management permits, as follows:

1. NPDES dischargers should submit (2) copies of the PPC plan for review, along with the NPDES application materials. All Stormwater General Permit applicants must complete and implement the Plans before or at the same time as application submission.

   Facilities which are not required to obtain NPDES permits, but which must obtain Water Quality Protection Part II permits, should submit (2) copies of the PPC plan for review, along with the Part II permit application.

2. Residual waste disposal/processing/transfer/composting facilities are required to develop and submit a PPC Plan as part of the residual waste permit application. Facilities permitted under permit-by-rule are required to develop PPC Plans and maintain them on site.

3. Municipal waste disposal/processing, transfer/composting facilities are required to develop and submit a PPC plan as part of the municipal waste permit application. Facilities permitted under permit-by-rule are required to develop PPC plans and maintain them on site.

   Other facilities which are not normally required to obtain NPDES or WQM Part II permits may also be required to develop and submit a PPC Plan, should conditions warrant, pursuant to Chapter 92 of the Department's regulations.

4. Hazardous waste generators are required to develop PPC plans and to maintain them on site. They are required to submit PPC plans to the Department for review upon request by the Department.

5. Hazardous waste treatment, recycling, storage, or disposal facilities should submit one copy of the PPC plan for each copy of the Hazardous Waste Part B permit application being submitted. In these situations the PPC plan is considered as part of the overall Hazardous Waste Part B permit application. Final PPC plan approval will accompany the issuance of a Hazardous Waste Management permit.

6. Aboveground storage tank facilities (with aggregate capacity >21,000 gallons) are required to submit one copy of the SPR plan to the appropriate regional DEP office for review. This plan must be developed in consultation with county and municipal emergency management agencies. Facilities that already have a PPC plan can update the PPC plan with the downstream notification requirement to satisfy this obligation.

7. Oil and gas well operators must prepare and implement a plan describing the measures to prevent pollution of the surface water and groundwater and for the control and disposal of pollutional substances and waste. A copy of the plan must be provided to the Department upon request.

D. Distribution of the Plan

A copy of the plan and any subsequent revisions must be maintained on-site. All members of the installation's organization for developing, implementing, and maintaining the plan and all emergency coordinators must review the plan and be thoroughly familiar with provisions.

In addition to the site copy and the copy submitted to the Department, other facility plans should be made available to the following agencies, to the extent which they may become involved in an actual emergency (see Description of PPC Plan Elements, Part E.1.):

Submission of copies to all of these entities is a legal requirement for hazardous waste facilities. Bulk aboveground storage tank facilities are required to submit copies to emergency management agencies, as noted below.

1. County and local Emergency Management Agencies. (This is a legal requirement for storage tank facilities with >21,000 gallons of above ground storage.)

2. Local Fire Service Agencies and/or Hazmat Team

3. Local Emergency Medical Service Agencies

4. Local Police

E. Implementation of the Plan

The provisions of the plan must be carried out whenever emergency situations arise which endanger public health and safety, or the environment.

F. Revisions of the Plan

The PPC Plan must be periodically reviewed and updated, if necessary. At minimum, this must occur when:

1. Applicable Department regulations are revised;

2. The plan fails in an emergency;

3. The installation changes in its design, construction, operation, maintenance, or other circumstances, in a manner that materially increases the potential for fires, explosions or releases of toxic or hazardous constituents; or which changes the response necessary in an emergency;

4. The list of emergency coordinators changes;

5. The list of emergency equipment changes; or

6. As otherwise required by the Department.

In addition to the above, the SPR or PPC plans must also be revised upon the removal or addition of a storage tank(s).

II. PLAN CONTENT AND FORMAT

General Instructions

A. Table 3 outlines the basic elements of a PPC and SPR Plan. Each of these elements is further described in this guidance document. Certain plan elements may not be entirely applicable or appropriate for a specific manufacturing or commercial installation. In these cases the person preparing the plan should act accordingly and should provide a brief explanation as to why the plan element(s) in question is not applicable or appropriate.

B. The most important thing to remember in developing your plan is that the actual effectiveness of the plan will depend upon its simplicity and readability.

Plans which are composed of several volumes of overly detailed narrative discussions and specifications tend to discourage the reader or user. Diagrams, charts, tables, maps, and plans must be easily readable and understandable, particularly in times of an actual emergency.

The plan should additionally be indexed or tabbed in such a way that the key portions which pertain to emergency response can be quickly referred to.

TABLE 3

ELEMENTS AND FORMAT OF A PPC AND SPR PLAN

A. Description of Facility

1. Description of the Industrial or Commercial Activity
2. Description of Existing Emergency Response Plans
3. Material and Waste Inventory
4. Pollution Incident History
5. Implementation Schedule for Plan Elements Not Currently in Place

B. Description of How Plan is Implemented by Organization

1. Organizational Structure of Facility for Implementation
2. List of Emergency Coordinators
3. Duties and Responsibilities of the Coordinator
4. Chain of Command

C. Spill Leak Prevention and Response

1. Pre release Planning
2. Material Compatibility
3. Inspection and Monitoring Program
4. Preventive Maintenance
5. Housekeeping Program
6. Security
7. External Factor Planning
8. Employe Training Program

D. Countermeasures

1. Countermeasures to be Undertaken by Facility
2. Countermeasures to be Undertaken by Contractors
3. Internal and External Communications and Alarm Systems
4. Evacuation Plan for Installation Personnel
5. Emergency Equipment Available for Response

E. Emergency Spill Control Network

1. Arrangements with Local Emergency Response Agencies
2. Notification Lists
3. Downstream Notification Requirement for Storage Tanks

DESCRIPTION OF PLAN ELEMENTS

A. Description of Facility

1. Description of the Industrial or Commercial Activity

- Briefly describe the nature of the industrial or commercial activity which occurs at the site. Include a general discussion of products manufactured, manufacturing processes used, wastes generated, etc.
- On a copy of a 7 1/2 minute USES map show the following:
  - Facility location
  - Facility name
  - Facility ID #
  - Name of 7 1/2 minute USES quadrangle
  - County
  - Location of facility site and site boundaries
  - Location of each storage tank
  - Location of surface drainage courses leading away from the site, and major surface streams and tributaries near the site
  - Location of any known public and private surface water intakes downstream from the site
- Include a drawing which shows the following:
  - General layout of the site
  - Property boundaries
  - Areas occupied by manufacturing or commercial activities
  - Raw materials and product storage
  - Loading and unloading operations
  - High risk areas where spills and leaks most likely would occur
  - Waste handling, storage, and treatment facilities
  - Drains, pipes, and channels which lead away from potential leak or spill areas
  - Outfall pipes which discharge to surface streams or drainage channels
  - Secure and open-access areas
  - Entrance and exit routes to the site

2. Description of Existing Emergency Response Plans

- Briefly describe any existing plan, which has been previously developed by the installation, for the purpose of pollution incident prevention or emergency response preparedness. If the plan has previously been approved by the Department, this should also be noted, along with the date of approval.

- Provide a brief discussion as to how the existing plan relates to the overall PPC or SPR Plan being developed. The degree to which the existing plan encompasses some, or all, of the PPC/SPR Plan elements should also be noted. When the PPC has been developed and an SPR plan is needed, the downstream notification requirement information can be added as an addendum.

  Similar plans which have been prepared for agencies other than DEP should also be described and cross-referenced to the maximum extent possible to the PPC Plan elements so as to minimize rewriting. For example, an oil related Spill Prevention Control and Countermeasure (SPCC) Plan which has been developed to comply with EPA's regulations 40 CFR 112, may be treated as an appendix, or as a separate chapter, to the overall PPC/SPR Plan for an installation.

3. Material and Waste Inventory

- Identify and list by common chemical name and trade name, the locations, sources and quantities of raw chemical materials, commercial chemical products, manufacturing chemical intermediates, and process wastes managed at the installation which have the potential for causing environmental degradation or endangerment of public health and safety through accidental releases. Requests for confidentiality of this information will be handled in accordance with Department regulations.

  Detailed descriptions must be available for materials that have a high potential for spills, discharges, explosions, or fires (such as those stored in bulk storage). Materials that have a low potential for spills, discharges, explosions, or fires (such as those used and stored in small quantities in a laboratory) should be minimally detailed.

  This information should be used to evaluate the prevention, containment, mitigation, cleanup, and disposal measures which would be used in the event of a spill, discharge, explosion, or fire. As new materials are added to the list, their pollution potential should be evaluated.

- Attach to this plan the Material Safety Data Sheet (MSDS) for each material in storage (the MSDS must be completed to the extent it meets the requirements of 29 CFR 1910.1200(9) Hazardous Communications Standard Requirements).

4. Pollution Incident History

- List the previous pollution incidents, the date, the material or waste spilled, approximate amount spilled, environmental damage, and action taken to prevent a recurrence.

  An important criteria in determining the effectiveness of the plan and its implementation is the history of incidents at the installation. A history of no incidents suggest that the practices and procedures at the site are effective. For a site with a history of incidents, it is important to investigate the reasons for the spills and the response of the company in minimizing the potential for their recurrence.

5. Implementation Schedule for Plan Elements Not Currently in Place

- Provide a list of any missing or incomplete aspects of the plan and a time schedule when they will be implemented.

  An implementation schedule, or any elements of the plan not currently in place, must be developed. Each missing or incomplete aspect of the plan should be addressed and discussed within the applicable elements of the plan. Missing or incomplete aspects must be implemented as soon as possible and in conformance with all Department regulations and requirements.

B. Description of How Plan is Implemented by Organization

1. Organizational Structure of Facility for Implementation

- Describe the organizational structure for implementation of the plan.
- Describe the duties and responsibilities of the individuals within the organization that will implement the plan.

  Each installation must develop a permanent organizational structure for developing, implementing, and maintaining the plan. The exact nature and make-up of this structure will vary considerably, depending upon the size and complexity of the installation.

  For example, a large manufacturing company may either establish a formal preparedness-response committee, or it may assign this responsibility to an existing organization within the company, such as a safety committee or a preventive maintenance group. A small manufacturing or commercial facility may only have one or two individuals responsible for developing and implementing the plan. However, the preparedness-response organization, regardless of its size, must be given both the responsibility and authority by management for developing, implementing, and maintaining the plan.

  The main duties and responsibilities of the preparedness-response organizational structure should include identification of materials and wastes handled (materials inventory), identification of potential spill sources (risk assessment), establishment of spill-reporting procedures, visual inspection programs review of past incidents and spills, and countermeasures utilized. In addition, the preparedness-response organizational structure should be responsible for coordination needed to implement the goals of the plan, coordination of the activities for spill cleanup, notification of authorities and establishment of training and educational programs for installation personnel.

  The preparedness response organizational structure should have the overall responsibility for periodically reviewing and evaluating the plan and instituting appropriate changes at regular intervals. The organizational structure should also be responsible for the review of new construction and process changes at an installation relative to the plan.

The organizational structure should also evaluate the effectiveness of the overall plan and make recommendations to management on related matters.

2. List of Emergency Coordinators

- Provide an up-to-date list of names, addresses, and phone numbers (office and home) of all persons qualified to act as emergency coordinator. Where more than one is listed, one must be named as the primary coordinator, and others shall be listed in the order in which they will assume responsibility as alternates.

  At all times there must be at least one employee either on the installation's premises or on-call with the responsibility for coordinating all emergency response measures. The emergency coordinator must be thoroughly familiar with all aspects of the plan, all operations and activities, the location and characteristics of all materials handled, the location of all records and the lay out of the installation. In addition, this individual should have the authority to commit the resources necessary to carry out the plan.

3. Duties and Responsibilities of the Coordinator

- Describe the duties and responsibilities of the emergency coordinator specific to your installation or activity in the event of an imminent or actual emergency.

  During an emergency, the emergency coordinator should activate alarm systems, notify emergency response agencies, identify the problem, assess the health or environmental hazards, and take all reasonable measures to stabilize the situation. The emergency coordinator should also be responsible for follow-up activities after the incident such as treating, storing, or disposing of residues and contaminated soil, decontamination and maintenance of emergency equipment, and submission of any reports. Appendix I describes some example duties and responsibilities of the emergency coordinator.

4. Chain of Command

- Provide an internal list, by position, of key employees that must be contacted in the event of an emergency or spill.

  List the positions, office telephone extensions, and home phone numbers (if applicable) of key employees, in the order of responsibility that would be contacted in the event of an emergency or spill.

  This list, along with the notification procedure, should be posted on bulletin boards or other conspicuous locations around the installation.

C. Spill Leak Prevention and Response

1. Pre-release Planning

- Describe the sources and areas where potential spills and leaks may occur, the direction of flow of spilled materials, and the pollution incident prevention practices (see Appendix II) specific to the source or area.

- Provide separate drawings, plot plans (or include in the general layout drawings), showing sources and quantities of materials and wastes. Sources and areas where potential spills may occur, and pollution incident prevention practices (see Appendix II).

  The plan should include a prediction of the direction of the flow of materials spilled as a result of equipment failure, accident, or human error. Particular care and attention should be paid to evaluating the following: raw materials storage, in plant transfer, process and materials handling, intermediary and product storage (if applicable), truck and rail car loading and unloading, and waste handling and storage. Describe and identify valving for the storage tank and system to be used to partition off each storage tank in case of a release.

  Liquid storage areas must have containment capacity sufficient to hold the volume of the largest single container or tank, plus a reasonable allowance for precipitation based on local weather conditions and plant operations. Containment systems must be sufficiently impervious to contain spilled material or waste until it can be removed or treated. Tank or container materials must be compatible with the material or waste stored.

  Pollution incident prevention practices to eliminate contaminated runoff, leaching, or windblowing must be implemented in non liquid storage areas. Provisions must be made to contain or manage contaminated run-off or leachate from these areas.

  Piping, processing, and materials handling equipment at in-plant transfer, process, and materials handling areas must be designed and operated so as to prevent spills. Containment practices should be instituted at processing and handling areas including floor drains, storm sewers, or drainage swales to prevent an accidental discharge. Protection such as covers or shields to prevent windblowing, spraying, and releases from pressure relief values from causing a discharge should be provided as appropriate.

  Truck and rail car loading and unloading areas must have sufficient containment capacity to hold the volume of the largest tank truck or rail car loaded or unloaded at the installation, plus a reasonable allowance for precipitation. Any overhead piping must have adequate clearance over roadways. Containment systems must be sufficiently impervious to contain spilled material or waste until it can be removed or treated.

2. Material Compatibility

- Summarize the engineering practices followed with regard to material compatibility such as materials of construction, corrosion, etc.

  Engineering practices with regard to material compatibility normally consist of an appraisement of the compatibility of construction materials of tanks, pipelines, etc., with their contents; the reaction of materials or wastes when intentionally or inadvertently mixed or combined; and, the compatibility of a container such as a storage tank or pipeline with its environment.

Specific consideration should be given to the procedures and practices delineating the mixing of materials and prohibiting mixing of incompatible materials which may result in fire, explosion, or unusual corrosion. Thorough cleaning of storage vessels and equipment before reuse should be standard practice to ensure that there is no residual incompatible with the next or later materials used. Coatings or cathodic protection should be considered for protecting buried pipelines or storage tanks from corrosion.

3. Inspection and Monitoring Program

- Describe the type and frequency of inspections and monitoring for leaks or other conditions that could lead to spills or emergency situations.

  Typical inspections include the following: pipes, pumps, values, and fittings for leaks; tanks for corrosion; tanks supports and foundations for deterioration; chemical material piles for windblowing; evidence of spilled materials along drainage ditches; effectiveness of housekeeping practices; damage to shipping containers; leaks, seeps, or overflows at waste treatment, storage, or disposal sites; etc. Areas that should be inspected include the following: storage, loading and unloading, transfer pipelines, waste treatment facilities, and disposal sites. The use of an inspection checklist may be useful in an inspection and monitoring program.

  Routine monitoring should be performed to determine the physical conditions and liquid levels in tanks, the quality of plant site runoff in diked areas, etc., either by manual testing or in-situ instrumentation. Monitoring should be used to initiate a warning of the need for immediate corrective action to prevent a spill or other emergency condition. Monitoring systems should be used in conjunction with a communications or alarm system to immediately notify personnel of abnormal conditions.

  An inventory system should also be considered for keeping track of those materials having the greatest potential for causing problems due to leaks, spills, or mishandling.

  As a minimum, the frequency of inspection and monitoring must be in accordance with the applicable Department regulations and permits. Appendix II includes some additional inspection and monitoring examples.

4. Preventive Maintenance

- Describe the aspects of the preventive maintenance program for equipment and systems relating to conditions that could cause environmental degradation or endangerment of public health and safety.

  Describe the procedures for the correction of those conditions by adjustment, repair, or replacement before the equipment or system fails.

  A good preventive maintenance program includes the following: (1) identification of equipment and systems to which the program should apply; (2) periodic inspections of identified equipment and systems; (3) periodic testing of equipment and systems, (such as routine calibration of environmental monitoring equipment); (4) appropriate adjustment, repair, or replacement of parts; and (5) complete recordkeeping of the preventive maintenance activities, inspection and test results, calibration dates, repairs, replacement, and adjustments to the applicable equipment and systems.

5. Housekeeping Program

- Identify the areas and the type of housekeeping practices that should apply to reduce the possibility of accidental spills and safety hazards to plant personnel.

  Examples of good housekeeping include the following: neat and orderly storage of chemicals; prompt removal of small spillage; regular refuse pickup and disposal; maintenance of dry, clean floors by use of brooms, vacuum cleaners, or cleaning machines; and, provisions for the storage of containers or drums to keep them from protruding into open walkways, pathways, or roads.

  Dry chemicals should be swept or cleaned up to prevent possible washdown to drains and drainage ditches or windblowing of the material to other areas of the plant. Small liquid accumulations on the ground or on a floor in a building should be cleaned up to prevent discharge or transport to other areas. See Appendix I for additional examples.

6. Security

- Describe the security procedures employed at the installation to prevent accidental or intentional entry that could result in a violation of Departmental regulations, or injury to persons or livestock.

  Security systems described in the plan should address, as necessary: fencing; lighting; vehicular traffic control; access control; visitors passes; locked entrances; vandalism; locks on drain valves and television monitoring. Security procedures must be in accordance with applicable Department regulations.

7. External Factor Planning

- Describe the possible effects of power outages, strikes, floods, snowstorms, etc., and the action to be taken to alleviate any resulting effects to public health and safety or the environment.

8. Employe Training Program

- Summarize the training program given to employees which will enable them to understand the processes and-materials with which they are working, the safety and health hazards, the practices for preventing, and the procedures for responding properly and rapidly to spills.

  At a minimum, the training program must be designed to ensure that personnel are able to respond effectively to emergencies by familiarizing them with emergency procedures, emergency equipment systems including, where applicable: procedures for using, inspecting, repairing, and replacing emergency and monitoring equipment; key parameters for automatic cut-off systems; communications and alarm systems; response to fires and explosions; site evacuation procedures; and shut down of operations.

In addition the employee training program should address other aspects of the preparedness-response program such as preventive maintenance, inspection and monitoring, housekeeping practices, etc. The training program must be designed and conducted in accordance with applicable Department regulations. Records of the employes' attendance in the training program should be included in personnel files.

D. Countermeasures

1. Countermeasures to be Undertaken by Facility

- Provide specific countermeasures which will be undertaken by facility personnel in the event of a release. Include valve activations, equipment isolations, flow diversions, boom deployment, and any other activities which will be undertaken to halt the migration of the contaminant off site and to mitigate the consequence of the release.

2. Countermeasures to be Undertaken by Contractors

- Provide a list of emergency response contractors, phone numbers, and the services they will provide.

  The services of nearby contractors should be investigated and arrangements made for the prompt performance of contractual services on short notice. Equipment suppliers should be contacted to determine the availability and means of delivery of equipment needed for removing pollution or hazards to the public health and safety. Describe arrangements with these contractors and the time frame in which they can respond with required equipment.

3. Internal and External Communications and Alarm Systems

- Describe the internal communications or alarm used to provide immediate emergency instruction (voice or signal) to installation personnel.
- Describe the external communications or alarm system used to summon emergency assistance from local police or fire departments.

  Examples of communications or alarm systems are: hand held two way radios; CB radios; telephones; fire or police alarms; PA systems; beeper or voice pagers, etc.

4. Evacuation Plan for Installation Personnel

- Describe the evacuation plan for facility personnel where there is a possibility that evacuation could be necessary.

  The plan must describe signals to be used to begin evacuation, primary evacuation route, and alternate evacuation routes (in cases where primary routes could be blocked by releases of hazardous materials, wastes, gases, or fires). Periodic drills should be conducted to evaluate the effectiveness of the plan.

5. Emergency Equipment Available for Response

- Provide an up-to-date list of available emergency equipment. The list must include the location, a physical description, and a brief description of the intended use and capabilities of each item on the list.
- Describe the procedures for maintenance and decontamination of emergency equipment.

All installations should have equipment available to allow personnel to respond safely and quickly to emergency situations. Some examples of emergency equipment are portable fire extinguishers, fire control equipment (including special extinguishing equipment such as that using foam, inert gas, or dry chemicals), spill control equipment, decontamination equipment, self contained breathing apparatus, gas masks, and emergency tool and patching kits. See Appendix III for more examples.

All equipment must be tested and maintained as necessary to assure its proper operation in time of emergency. After an emergency, all equipment must be decontaminated, cleaned, and fit for its intended use before normal operations resume.

E. Emergency Spill Control Network

1. Arrangements with Local Emergency Response Agencies and Hospitals

- Provide a list of local emergency response agencies and hospitals. Include the phone numbers and describe arrangements concerning the emergency services they will provide.

Arrangements must be made, as appropriate, to inform local emergency response agencies, and hospitals concerning the type of materials or wastes handled at the installation and the potential need for services. Arrangements should be made which will designate who will be the primary emergency response agency and who will provide support services during emergencies.

Efforts should be made to familiarize police, fire departments, emergency response teams, and the County Emergency Management Coordinator with the layout of the installation, the properties and dangers associated with the hazardous materials handled, places where personnel would normally be working, entrances to roads inside the facility, and the possible evacuation routes. At a minimum, this requirement must be in accordance with applicable Department regulations.

2. Notification Lists

- Provide a list of agencies and phone numbers that must be contacted in the event of an emergency or spill.

A list must be developed for notifying State, local, and Federal regulatory agencies of all spills. Such a list should include, as applicable: PA DEP (see Appendix IV); PA Emergency Management Agency; County Health Department; County EMA; PA Fish Commission; the National Response

Center (U.S. EPA and U.S. Coast Guard); local police and fire departments; the local sewage treatment plant (for discharges to sewer system); and downstream public water supplies, industrial water users, and recreation areas.

3. Downstream Notification Requirement for Storage Tanks

- This is an additional requirement of storage tank facilities with aggregate aboveground storage >21,000 gallons of regulated substances. It can be addended to an updated PPC plan so as to meet the SPR plan requirement.

  The requirement includes a 20-mile downstream Notification List, an annual notification requirement, and an annual Notification List update. Lists of downstream users may be developed from information provided by your county Emergency Management Agency.

  Downstream Notification List shall include all municipalities and surface water users within 20 downstream miles of the tank facility. Surface water users include drinking water companies, and industries that utilize surface water intakes; and municipalities include each county, township, city and borough located within this downstream corridor. This list is to be developed via assistance from the local emergency management agency. (Refer to Appendix V for an example.)

  Annual Written Notification must be given to downstream water users and municipalities on the Notification List. This written notification at a minimum must include a detailed inventory of the type and quantity of material in storage at the facility.

  Annual Update must be developed each year in cooperation with the local Emergency Management Agency. This Notification List update will show any changes in contacts, users, telephone #'s needed for emergency downstream notification and the annual written notification. Also, any changes in the emergency response organization (such as telephone numbers) should be updated.

APPENDIX I

EXAMPLES OF AN EMERGENCY COORDINATOR'S DUTIES AND RESPONSIBILITIES

Whenever there is an imminent or actual emergency situation, the emergency coordinator must immediately:

1. Activate facility alarms or communications systems, where applicable, to notify facility personnel; and
2. Notify local emergency response agencies including the Department.

Whenever there is an emission or discharge, fire, or explosion, the emergency coordinator must immediately identify the character, exact source, amount, and areal extent of emitted or discharged materials. He may do this by observation or review of records and, if necessary, by chemical analysis.

Concurrently, the emergency coordinator must assess possible hazards to human health or the environment that may result from the emission or discharge, fire, or explosion. This assessment must consider both direct and indirect effects of the emission, discharge, fire, or explosion.

If the emergency coordinator determines that the installation has had an emission, discharge, fire, or explosion which would threaten human health or the environment, he must immediately notify the applicable local authorities including the county emergency management agency and indicate if evacuation of local areas may be advisable; and immediately notify the Department in accordance with Appendix IV; the National Response Center; and the Pennsylvania Emergency Management Agency; and report the following:

a. Name of the person reporting the incident
b. Name and location of the installation
c. Phone number where the person reporting the spill can be reached
d. Date, time, and location of the incident
e. A brief description of the incident, nature of the materials or wastes involved, extent of any injuries, and possible hazards to human health or the environment
f. The estimated quantity of the materials or wastes spilled, and
g. The extent of contamination of land, water, or air, if known.

When there is a release from an aboveground storage tank which threatens the water supply of downstream users, these downstream users (on the Downstream Notification List) must be notified within 2 hours of the release. Priority for notification is by closest proximity to the release site.

During an emergency, the emergency coordinator must take all reasonable measures necessary to ensure that fire, explosion, emission, or discharge do not occur, reoccur, or spread to other materials or wastes at the installation. These measures shall include where applicable, stopping manufacturing processes and operations, collecting and containing released materials or wastes, and removing or isolating containers.

If the installation stops operations in response to a fire, explosion, emission, or discharge, the emergency coordinator must ensure that adequate monitoring is conducted for leaks, pressure buildup, gas generation, or ruptures in valves, pipes, or other equipment, wherever this is appropriate.

Immediately after an emergency, the emergency coordinator, with Departmental approval, must provide for treating, storing, or disposing of residues, contaminated soil, etc., from an emission, discharge, fire, or explosion at the installation.

The emergency coordinator must insure that in the affected areas of the installation, no material or waste incompatible with the emitted or discharged residues is processed, stored, treated, or disposed of until cleanup procedures are completed; and, all emergency equipment listed in the plan is cleaned and fit for its intended use before operations are resumed.

Within 15 days after the incident, the installation must submit a written report on the incident to the Department. The report must include the following:

a. Name, address, and telephone number of the individual filing the report

b. Name, address, and telephone number of the installation

c. Date, time, and location of the incident

d. A brief description of the circumstances causing the incident

e. Description and estimated quantity by weight or volume of materials or wastes involved

f. An assessment of any contamination of land, water, or air that has occurred due to the incident

g. Estimated quantity and disposition of recovered materials or wastes that resulted from the incident, and

h. A description of what actions the installation intends to take to prevent a similar occurrence in the future.

APPENDIX II
POLLUTION INCIDENT PREVENTION PRACTICES

Pollution incident prevention practices can be divided into the following four categories: prevention, containment, mitigation and ultimate disposition. The listings below provide specific examples of each category.

1. PREVENTION

Visual Observations of:

Storage facilities
Transfer pipelines
Loading and unloading areas
Waste handling and storage areas

Detailed Inspections of:

Pipes, pumps, valves, and fittings for leaks
Tanks for corrosion (internal and external)
Dry material or waste stockpiles for windblowing
Tanks supports or foundations for deterioration
Walls for stains
Drainage ditches and areas around old tanks for evidence of spilled materials
Primary or secondary containment for deterioration
Housekeeping practices
Shipping containers for damage
Material or waste conveyance systems for leaks, spills, or overflows
Integrity of stormwater collection systems
Waste storage, treatment, or disposal sites for leaks, seeps, and overflows

Monitoring

Liquid-level detectors
Alarm systems
Pressure and temperature gauges
Analytical testing instrumentation
Pressure drop shut-off devices
Flow meters
Valve positioning indicators
Equipment operational lights
Excess-flow valves
Automatic runoff diversion devices
Routine sample collection (including groundwater and monitoring wells)
Redundant instrumentation
Records (all monitoring results/findings)

Nondestructive Testing

Hydrostatic pressure tests
Acoustical emission tests
Radiographic tests
Magnetic particle tests
Liquid Penetration
Records of tank wall thicknesses and results of all testing

2. CONTAINMENT

Secondary Containment

Dikes
Curbs
Depressed areas
Storage basins
Sumps
Drip pans
Liners
Double piping
Sewer collection systems

Flow Diversion

Trenches
Drains
Graded pavement
Grating
Overflow structures
Sewers
Culverts

Vapor Control

Water spray
Vapor space
Vacuum exhaust

Dust Control

Hoods
Cyclone collectors
Bag-type collectors
Filters
Negative-pressure systems
Water spraying

Sealing

Foamed plastic compounds used for plugging leaks in tanks

3. MITIGATION

Physical Clean-up

Brooms
Shovels
Plows

Labeling

U.S. DOT or National Fire Protection Association's (NFPA) designation on tanks and pipelines
Color coding of tanks and pipelines
Warning signs

Vehicle Positioning

- Physical barriers (e.g., wheel chocks)
- Underlying drains
- Designated loading and unloading areas

Covering

- Tarpaulins over outdoor dry waste or material stockpiles
- Buildings or roofs over outside processes or stockpiles
- Vegetation, rock, or synthetic covering on surface impoundments

Pneumatic and Vacuum Conveying

- Loading and unloading by air pressure or vacuum
- Safety relief valves
- Dust collectors
- Air slide trucks and rail cars

Preventive Maintenance

- Periodic inspections
- Periodic testing to determine soundness of system
- Identification of equipment and systems that need to be upgraded, repaired, or replaced
- Appropriate adjustment, repair, or replacement of parts
- Complete recordkeeping of all repairs, upgrading, replacements, and adjustments; and all testing findings/results after system modifications were made

Good Housekeeping

- Neat and orderly storage of chemicals
- Prompt removal of small spillage
- Regular garbage pickup and disposal
- Maintenance of dry, clean floors by use of brooms, vacuum cleaners, etc.
- Maintenance of proper spacing for pathways and walkways between containers and drums
- Stimulation of employee interest in good housekeeping

Employee Training Programs

- Materials Inventory Systems
- Material Safety Data Sheets

Mechanical Clean up

- Vacuum systems
- Pumps
- Pump/bag system

Chemical Clean up

Sorbents

- activated carbon
- polyurethane and polyolefin spheres, beads, and foam belts
- amorphous silicate glass foam
- clay
- sawdust

Gelling agents

polyelectrolytes
polyacrylamide
butylstyrene copolmyers
polyacrylonitrile
polyethylene oxide

Foams

rockwood alcohol
protein
fluoroprotein
aqueous film-forming foam
polar liquid foam
surfactant-based foam

Volatilization

distillation
stripping
evaporation

Carbon absorption
Coagulation/precipitation
Neutralization
Ion exchange
Chemical oxidation
Biological treatment

4. ULTIMATE DISPOSITION

Thermal oxidation
Land disposal
Recycle
Recover
Reuse
Detoxification

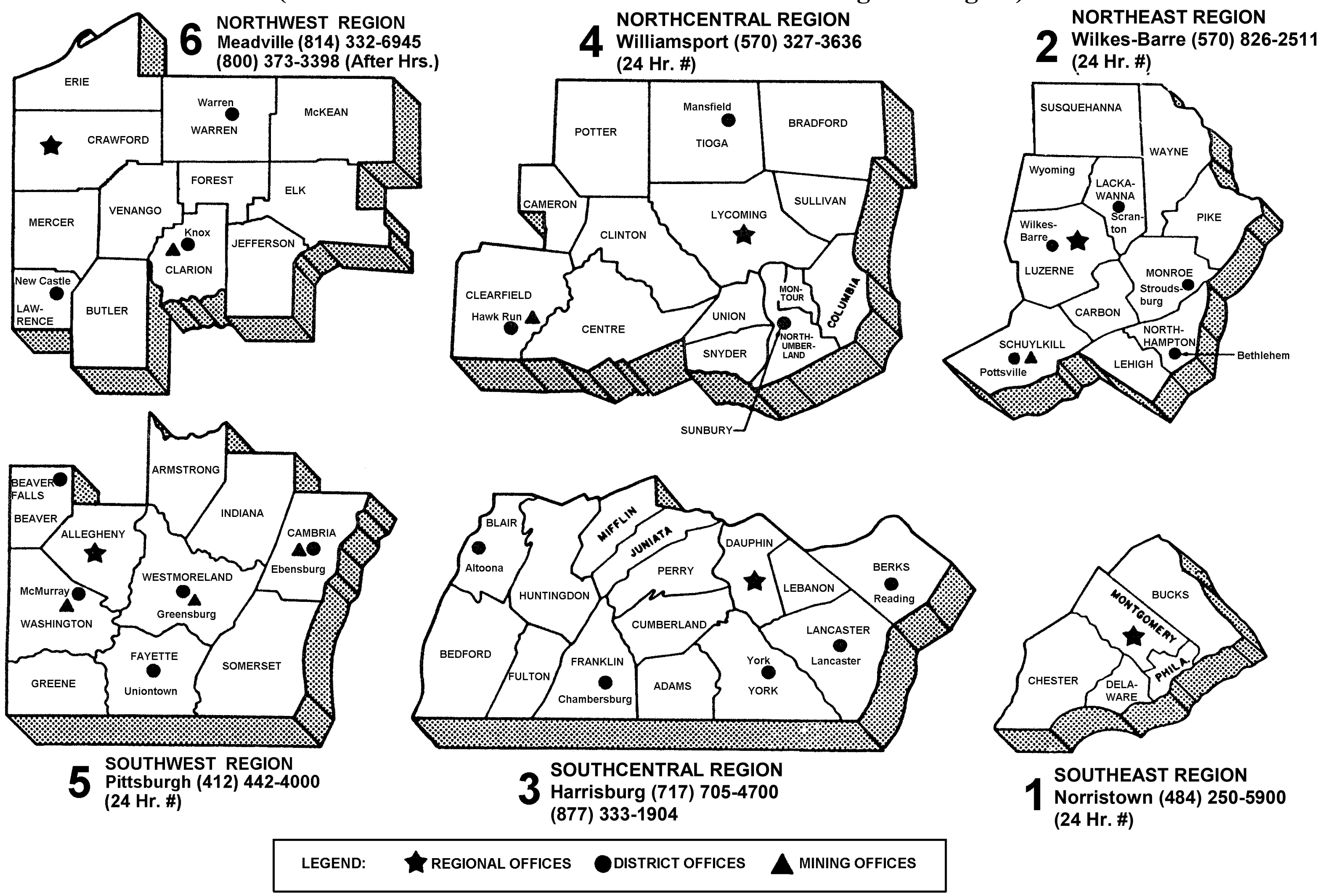
APPENDIX III
EXAMPLES OF EMERGENCY EQUIPMENT

Special equipment is often required and may be needed quickly in an emergency. Examples include the following:

Aerial ladder
Absorbant materials
Accident investigation kit
Air compressor
Air supply, for breathing equipment
Backhoe
Basket stretchers
Bulldozer
Bullhorn
Camera/photo equipment
Cellar pump
Chain hoist
Chain saw
Chemical neutralizers
Crane
Cutters (power)
Decontamination equipment with a clean Resuscitator water supply (70-80%F)
Ejector - smoke
Elevated platform truck
Explosimeters
Fans
Firefighting equipment
First aid supplies
Foam concentrate supply
Foam generators
Forklift
Fuel Supply
Geiger counter
Generator trailer
Heaters, portable
Helicopter
Hydraulic spreader jacks
Inhalator
Jack hammer
Jacks
Ladder Truck
Lighting equipment, portable
Medical supplies
Metal saw (power)
Public address system
Radio
Resuscitator
Sand supply
Self-contained breathing apparatus (SCBA)
Self-contained underwater breathing apparatus (SCUBA)
Submersible pump
Tank truck
Tool box
Welding/cutting equipment
Water pump

APPENDIX IV
COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION
EMERGENCY NOTIFICATION NUMBERS

STATEWIDE EMERGENCY NOTIFICATION NUMBER (800) 541-2050 (PA ONLY)
OR (717) 787-4343
(To Be Used If There Is A Problem In Contacting The Region)



APPENDIX V
PENNSYLVANIA DEPARTMENT OF ENVIRONMENTAL PROTECTION
Field Operations--Environmental Cleanup Program
Regional Storage Tank List

Region	Contact
Southeast Regional Office 2 East Main Street Norristown, PA 19401-4915 Telephone: (484) 250-5900	Kathy Nagle
Northeast Regional Office 2 Public Square Wilkes-Barre, PA 18711-0790 Telephone: (570) 826-2511	Ron Brezinski
Southcentral Regional Office 909 Elmerton Avenue Harrisburg, PA 17110-8200 Telephone: (717) 705-4700	Gregory Bowman
Northcentral Regional Office 208 W. Third Street Williamsport, PA 17701 Telephone: (570) 327-3636	Steve Webster
Southwest Regional Office 400 Waterfront Drive Pittsburgh, PA 15222 Telephone: (412) 442-4000	Gale Campbell
Northwest Regional Office 230 Chestnut Street Meadville, PA 16335 Telephone: (814) 332-6945	Daniel F. Peterson

In the event no contact with the Regional Office is made, the Department Emergency number (717) 787-4343 shall receive calls during and after business hours, 24 hours daily and holidays and weekends.

Oil and Gas Management Program

South Regional Office 400 Waterfront Drive Pittsburgh, Pa 15222-4745 (412) 442-4000	David F. Janco
Northwest Regional Office 230 Chestnut Street Meadville, PA 16335 (814) 332-6945	Craig Lobins

PENNSYLVANIA DEPARTMENT OF ENVIRONMENTAL PROTECTION
Field Operations--Water Management

Region	Contact
Southeast Regional Office 2 East Main Street Norristown, PA 19401-4915 Telephone: (484) 250-5900	James Newbold
Northeast Regional Office 2 Public Square Wilkes-Barre, PA 18711-0790 Telephone: (570) 826-2511	Kate Crowley
Southcentral Regional Office 909 Elmerton Avenue Harrisburg, PA 17110-8200 Telephone: (717) 705-4700	Jim Spontak
Northcentral Regional Office 208 W. Third Street Williamsport, PA 17701 Telephone: (570) 327-3636	Daniel Alters
Southwest Regional Office 400 Waterfront Drive Pittsburgh, PA 15222 Telephone: (412) 442-4000	Steve Balta
Northwest Regional Office 230 Chestnut Street Meadville, PA 16335 Telephone: (814) 332-6945	Dave Milhous

PENNSYLVANIA DEPARTMENT OF ENVIRONMENTAL PROTECTION
Field Operations--Waste Management
Regional Contact

Region	Contact
Southeast Regional Office 2 East Main Street Norristown, PA 19401-4915 Telephone: (484) 250-5900	Facilities Manager
Northeast Regional Office 2 Public Square Wilkes-Barre, PA 18711-0790 Telephone: (570) 826-2511	Facilities Manager
Southcentral Regional Office 909 Elmerton Avenue Harrisburg, PA 17110-8200 Telephone: (717) 705-4700	Facilities Manager
Northcentral Regional Office 208 W. Third Street Williamsport, PA 17701 Telephone: (570) 327-3636	Facilities Manager
Southwest Regional Office 400 Waterfront Drive Pittsburgh, PA 15222 Telephone: (412) 442-4000	Facilities Manager
Northwest Regional Office 230 Chestnut Street Meadville, PA 16335 Telephone: (814) 332-6945	Facilities Manager

APPENDIX VI
IGMARS STORAGE FACILITY
Harrisonberg, PA
Example
DOWNSTREAM NOTIFICATION LIST FOR YEAR 1992

Facility	Address	Mile Mark	Contact	Telephone
Harrison County	PO Box 15 Harrison Co. Courthouse Harrisonberg, PA	-	Ronald Swoyer Co. Emergency Mgt. Coordinator	Office: (717) 674-1212 Emergency: (717) 674-3434
Greenly Township	PO Box 498, RD 1 Harrisonberg, PA 19865	0	Donald Trump	Office: (717) 765-3468 Emergency: (717) 765-4579
Harrisonberg City	PO Box 21, City Hall Harrisonberg, PA 19869	3	Jay Miller	Office: (717) 674-2185 Emergency: (717) 674-2194
Harrisonberg Water	Harrisonberg, PA	6	Richard Miles	Office: (717) 254-8904 Emergency: (717) 254-8910
Harrison Township	Harrison Township Building Krissville, PA 19872	10	Charles Davis Township Manager	Office: (717) 760-3120 Emergency: (717) 760-3123
Harrison Township Auth.	PO Box 234 Krissville, PA 19870	12	Kemp Olsen Auth. Manager	Office: (717) 760-2334 Emergency: (717) 760-2333
Villa Assoc.	Box 29 Krissville, PA 19880	14	George Kay	Office: (717) 675-8960 Emergency: (717) 675-8961
Harrison Water Auth.	Box 28 Krissville, PA 19879	16	Justine Keener	Office: (717) 675-9004 Emergency: (717) 675-9005

Igmars Emergency Coor.   Date

NOTE: This Downstream Notification List when annually updated should be dated for the year updated and signed by the storage tank facility's emergency coordinator.

ADDENDUM

COMMONWEALTH OF PENNSYLVANIA
DEPARTMENT OF ENVIRONMENTAL PROTECTION

SUPPLEMENTAL GUIDANCE FOR THE DEVELOPMENT AND IMPLEMENTATION OF PREPAREDNESS, PREVENTION AND CONTINGENCY (PPC) PLANS UNDER THE NATIONAL POLLUTANT DISCHARGE ELIMINATION SYSTEM (NPDES) STORM WATER PERMITTING PROGRAM

September 2001

BUREAU OF WATER STANDARDS AND FACILITY REGULATION
DIVISION OF PLANNING AND PERMITS

FORWARD

The "Supplemental Guidance for the Development and Implementation of Preparedness, Prevention and Contingency (PPC) Plans under the National Pollutant Discharge Elimination System (NPDES) Storm Water Permitting Program" has been prepared to provide those owners, operators, and municipalities who must prepare Preparedness, Prevention and Contingency (PPC) Plans (in accordance with the General Permit for Discharges of Storm Water from Industrial Activities and the Department's Chapter 91 regulations) with guidance on what storm water issues must be addressed. This supplemental guidance, when used with the existing guidance entitled "Guidelines for the Development and Implementation of Environmental Emergency Response Plans", hereafter called the PPC guidance or guidelines, will provide complete information on incorporating the new storm water requirements into existing or new PPC Plans for facilities seeking coverage under the general permit to discharge storm water associated with industrial activity.

Section 1 provides an introduction to the regulatory requirements for storm water discharges, the General Permit for Discharges of Storm Water From Industrial Activities and the special condition within the permit to develop and implement a Preparedness, Prevention and Contingency Plan.

Section 2 follows the format of the original guidelines. Where changes must be incorporated to address the new storm water requirements, the necessary modifications or addendums are explicitly presented.

It is emphasized that the original guidance pertains to emergency response plans that include potential releases, their controls, and management practices that are applicable to facilities regardless of whether they discharge storm water associated with industrial activity. The supplemental guidance's requirements, on the other hand, have specific requirements that focus exclusively on managing storm water discharges associated with industrial activity.

SECTION 1

INTRODUCTION

The Department of Environmental Protection is authorized by law to protect the quality of both surface and underground waters of the Commonwealth through the prevention and abatement of water pollution. Specifically, the federal Clean Water Act and the Pennsylvania Clean Streams Law require that all point source discharges of pollutants be authorized and regulated under a National Pollutant Discharge Elimination System (NPDES) permit. Point source discharges that are not regulated under a NPDES permit are in violation of the federal Clean Water Act and the Pennsylvania Clean Streams Law, and may be subject to applicable penalties and fines.

Recent revisions to the federal NPDES regulations (55 FR 47990; November 16, 1990) require that permit applications be submitted and NPDES permits be issued for storm water discharges associated with industrial activity (see the Bureau of Water Quality Management's "Notice of Intent Requirements for Coverage Under the General Permit for Discharges of Storm Water From Industrial Activities" for definition of industries covered). In accordance with the Department's regulations at 25 Pa. §§92.81 - 92.83, the Department of Environmental Protection has developed and issued a general NPDES permit that sets forth the requirements and conditions to control storm water discharges from industrial activities.

Special Permit Condition for the Development and Implementation of a PPC Plan

The General Permit for Discharges of Storm Water from Industrial Activities requires operators of facilities covered under the permit to develop and implement a Preparedness, Prevention and Contingency (PPC) Plan in accordance with 25 Pa. Code §91.34 and the PPC guidelines contained in this document prior to authorization to discharge under this general permit.[1] The PPC Plan, once implemented, will provide best management practices (BMPs) to control the discharges of pollutants to receiving waters. In general, the PPC Plan is required to identify potential sources of pollution which may reasonably be expected to affect the quality of storm water discharges associated with industrial activity from the facility. In addition, the PPC Plan is required to describe the implementation of practices that are to be used to reduce the pollutants in storm water discharges associated with industrial activity at the facility.

This supplemental guidance provides the additional elements and requirements needed to address storm water issues in the PPC Plan required under the general permit. When used in conjunction with this document, the terms and conditions of the permit should be satisfied and the appropriate "spill prevention control" and "storm water control" - requirements should be addressed.

[1] See Part C.3.a. of the General permit.

SECTION 2

MODIFICATIONS TO EXISTING ELEMENTS AND FORMAT OF THE PPC PLAN

Modify or add to Section II of the PPC guidance, the elements beginning with A (Description of Facility). Each modification or addendum is identified explicitly in the following pages using the format contained in this document. In cases where no modifications to the original guidelines are necessary, the element heading is presented and the user is referred to the requirements in the PPC guidance. Again, users or developers of PPC Plans that meet the requirements of a general permit to discharge storm water associated with industrial activity must fulfill all of the requirements of the PPC guidance and the additional requirements and addendums of this supplemental guidance.

A. Description of Facility

1. Description of the Industrial or Commercial Activity

Add the following to the requirements in the original guidance for this section.

- Provide a narrative description of significant materials[2] that have been treated, stored or disposed in a manner to allow exposure to storm water within the three years prior to the issuance of the general permit and the present; the method of on-site storage or disposal; materials management practices that were employed to minimize contact of these materials with storm water runoff between the time of three years prior to the date of the issuance of this permit and the present; materials loading and access areas; the location and a description of existing structural and nonstructural control measures to reduce pollutants in storm water runoff; and a description of any treatment the storm water receives.
- On the 7 1/2-minute USGS map show the following:
  - -- Provide an outline of the drainage area for each storm water outfall.
- On the drawings required in the original guidance show the following:
  - -- Indicate existing structural control measures to reduce pollutants in storm water runoff.
  - -- Identify commercial and industrial activities that are exposed to precipitation to include fueling stations, vehicle and equipment maintenance and/or cleaning areas, loading/unloading areas, locations used for treatment, storage or disposal of wastes, liquid storage tanks, and processing areas.

2. Description of Existing Emergency Response Plans

Refer to the requirements in the original guidance.

3. Material and Waste Inventory

Refer to the requirements in the original guidance.

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2 Significant materials includes, but is not limited to: raw materials; fuels, materials such as solvents, detergents, and plastic pellets; finished materials such as metallic products; raw materials used in food processing or production; hazardous substances designated under section 101(14) of CERCLA; any chemical the facility is required to report pursuant to EPCRA Section 313; fertilizers; pesticides; and waste products such as ashes, slag and sludge that have the potential to be released with storm water discharges.

4. **Pollution Incident History**

Add the following to the requirements in the original guidance for this section.

- Provide a list of significant leaks and spills[3] of toxic and hazardous pollutants that occurred in areas that are exposed to precipitation or that otherwise drain to a storm water conveyance at the facility after the date of three years prior to the effective date of the permit. This list shall be updated as appropriate during the permit.

5. **Implementation for Plan Elements Not Currently in Place**

Refer to the requirements in the original guidance.

B. **Description of How Plan is Implemented by Organization**

1. **Organizational Structure of Facility for Implementation**

Refer to the requirements in the original guidance.

2. **List of Emergency Coordinators**

Refer to the requirements in the original guidance.

3. **Duties and Responsibilities of the Coordinator**

Refer to the requirements in the original guidance.

4. **Chain of Command**

Refer to the requirements in the original guidance.

C. **Spill Leak Prevention and Response**

1. **Pre-release Planning**

Add the following to the requirements in the PPC guidance for this section.

- Assess the potential of various sources at the plant to contribute pollutants to storm water discharges. Each of the following shall be evaluated for the reasonable potential for contributing pollutants to runoff: loading and unloading operations; outdoor storage activities; outdoor manufacturing or processing activities; significant dust or particulate generating processes; and on-site waste disposal practices. Consider the toxicity of chemicals; quantity of chemicals used, produced, or discharged; the likelihood of contact with storm water; and history of significant leaks or spills of toxic or hazardous pollutants. The description shall specifically list any significant potential source of pollutants at the site and for each potential source, any pollutant or pollutant parameter of concern (e.g., biochemical oxygen demand).
- Describe pollution incident prevention practices in storage areas used for the storage of salts for deicing or other commercial or industrial purposes. Storage piles of salt used for deicing or other commercial or industrial purposes and which generate a storm water discharge associated with industrial activity which is discharged to a waters of the United States

[3] Significant spills includes, but is not limited to: releases of oil and hazardous substances in excess of reportable quantities under Section 311 of the Clean Water Act (see 40 CFR 110.10 and CFR 117.21) or section 102 of CERCLA (see 40 CFR 302.4).

shall be enclosed or covered to prevent exposure to precipitation, except for exposure resulting from adding or removing materials from the pile. Dischargers shall demonstrate compliance with this provision as expeditiously as practicable, but in no event later than October 1, 1995. Piles do not need to be enclosed or covered where storm water from the pile is not discharged to waters of the United States.

2. Material Compatibility

Refer to the requirements in the PPC guidance.

3. Inspection and Monitoring Program

Add the following to the requirements in the PPC guidance for this section.

- Identify qualified personnel to conduct site compliance evaluations for storm water discharges associated with industrial activities, but in no case, less than once per year. Such evaluations will provide the following:

  Visually inspect areas contributing to storm water discharges associated with industrial activity for evidence of, or the potential for, pollutants entering the drainage system. Measures to reduce pollutant loadings should be evaluated to determine whether additional control measures are needed. Structural storm water management measures, sediment and erosion control measures, and other structural pollution prevention measures identified in the plan should be observed to ensure that they are operating correctly. A visual inspection of equipment needed to implement the plan, such as spill response equipment, should be made.

  Based on the results of these inspections, potential pollutant sources identified (Section C) and control measures (i.e., good housekeeping, preventive maintenance, spill prevention and response), should be revised as necessary within 15 days of the inspection. The revision will provide for the implementation of any changes to the PPC plan in a timely manner, but in no case later than 90 days after the inspection.

  A report summarizing the scope of the inspection, personnel making the inspection, the date(s) of the inspection, major observations relating to the implementation of the PPC plan, and any actions taken as a result, should be retained for a period of at least one year after coverage under this permit terminates. This report will identify any incidents of non-compliance. Where a report does not identify any incidents of non-compliance, the report should contain a certification that the facility is in compliance with the PPC plan and the permit. This report shall be signed in accordance to the signatory requirements stipulated in the general permit.

  Where annual site inspections are shown in the plan to be impractical for inactive mining sites due to the remote location and inaccessibility of the site, site inspections required under this part should be conducted at appropriate intervals specified in the plan, but, in no case less than once in three years.

4. Preventive Maintenance

Add the following to the requirements in the PPC guidance for this section.

- Describe the aspects of the preventive maintenance program. This program should involve the timely inspection and maintenance of storm water management devices (e.g., cleaning oil/water separators, catch basins, etc.) as well as inspecting and testing plant equipment and systems to uncover conditions that could cause breakdowns or failures resulting in discharges of pollutants to surface waters. Records of these maintenance procedures should be maintained.

5. Housekeeping Program

Add the following to the requirements in the PPC guidance for this section.

- Establish housekeeping protocols to ensure the proper handling of materials and the maintenance of a clean, orderly facility to prevent pollutants from entering separate storm water sewers and/or to prevent contact with storm water runoff.

6. Security

Refer to the requirements in the PPC guidance.

7. External Factor Planning

Refer to the requirements in the PPC guidance.

8. Employee Training Program

Add the following to the requirements in the PPC guidance for this section.

- Employee training should inform personnel responsible for implementing activities identified in the storm water pollution prevention plan or otherwise responsible for storm water management at all levels of responsibility of the components and goals of the storm water pollution prevention plan. Training should address topics such as spill response, good housekeeping and material management practices. A pollution prevention plan shall identify periodic dates for such training.

D. Countermeasures

1. Countermeasures to be Undertaken by Facility

Refer to the requirements in the PPC guidance.

2. Countermeasures to be Undertaken by Contractors

Refer to the requirements in the PPC guidance.

3. Internal and External Communications and Alarm Systems

Refer to the requirements in the PPC guidance.

4. Evacuation Plan for Installation Personnel

Refer to the requirements in the PPC guidance.

5. Emergency Equipment Available for Response

Refer to the requirements in the PPC guidance.

E. **Emergency Spill Control Network**

1. **Arrangements with Local Emergency Response Agencies and Hospitals**

   Refer to the requirements in the PPC guidance.

2. **Notification Lists**

   Refer to the requirements in the PPC guidance.

3. **Downstream Notification Requirements for Storage Tanks**

   Refer to the requirements in the PPC guidance.

THE ELEMENTS F THROUGH J ARE <u>ADDENDUMS</u> TO THE ORIGINAL GUIDANCE.

The PPC plan should also meet the requirements stipulated in these addendums to the PPC guidance. All of the management practices required for facilities (including EPCRA Section 313 facilities) are to be implemented and described in the plan.

F. **Storm Water Management Practices**

- Provide a narrative considering the appropriateness of traditional storm water management practices (practices other than source control) and the use of BMPs to control storm water runoff and prevent storm water pollution. Based on an assessment of the potential of various sources at the plant to contribute pollutants to storm water, provide that measures determined to be reasonable and appropriate, be implemented and maintained.

  Traditional storm water management practices are measures which reduce pollutant discharges by reducing the volume of storm water discharges, such as swales, or preventing storm water to run-on to areas of the site which conduct industrial activities. Low cost measures may include diverting rooftop or other drainage across grass swales, cleaning catch basins, and installing and maintaining oil and grit separators. Other measures may include infiltration devices and unlined retention and detention basins. Traditional storm water management practices can also include water reuse activities and snow removal activities.

- The PPC plan shall include a certification that the discharge has been tested or evaluated for the presence of non-storm water discharges. The certification shall include the identification of potential significant source of non-storm water at the site. A description of the results of any test and/or evaluation for the presence of non-storm water discharges, the evaluation criteria or testing method used, the date of any testing and/or evaluation, and the on-site drainage points that were directly observed during the test.

G. **Sediment and Erosion Prevention**

- In the PPC plan, identify areas which, due to topography, activities, or other factors, have a high potential for significant soil erosion, and identify measures to limit erosion.

  Sediment and erosion prevention and control measures should be developed and implemented in accordance with Chapter 102 of the Department's rules and regulations and the Bureau of Soil and Water Conservation's "Erosion and Sediment Pollution Control Program Manual."

H. Additional Requirements for EPCRA, Section 313 Facilities[4]

- Describe the types of storm water controls (containment, drainage control and/or diversionary structures) that will be used in areas where Section 313 water priority chemicals are stored,[5] processed or otherwise handled.

  Storm water controls should provide for the following preventive systems or its equivalent: Curbing, culverting, gutters, sewers or other forms or drainage control to prevent or minimize the potential for storm water run-on to come into contact with significant sources of pollutants; or roofs, covers or other forms of appropriate protection to prevent storage piles from exposure to storm water and wind blowing.

- In addition to the minimum standards for EPCRA Section 313 facilities, the storm water pollution prevention plan will meet the following requirements for liquid storage areas, material storage areas other than liquids, truck and rail car loading and unloading areas for liquid Section 313 water priority chemicals:

  -- Liquid storage areas where storm water comes into contact with any equipment, tank container, or other vessel used for Section 313 water priority chemicals.

- No tank or container shall be used for the storage of a Section 313 water priority chemical unless its material and construction are compatible with the material stored and conditions of storage such as pressure and temperature, etc.

- Secondary containment must be provided to contain the entire capacity of largest single container or tank plus sufficient freeboard to allow for precipitation, a strong spill contingency and integrity testing plan, and/or other equivalent measures. If the secondary containment and its upstream drainage system are subject to precipitation, an allowance for drainage for a 25-year, 24-hour storm event shall be provided over and above. Secondary containment shall be sufficiently impervious. Plant's treatment system may be substituted for secondary containment if it has sufficient excess holding capacity always available.

  -- Material storage areas for Section 313 water priority chemicals other than liquids.

- Material storage areas for Section 313 water priority chemicals other than liquids which are subject to runoff, leaching, or wind shall incorporate drainage or other control features which will minimize the discharge of Section 313 water priority chemicals.

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4 An "EPCRA, Section 313 Facility" means a facility that manufactures, imports, processes, or otherwise uses listed toxic chemicals and who, pursuant to Section 313 of Title III of SARA, are required to report annually their releases of those chemicals to any environmental media.

5 Section 313 water priority chemical means a chemical or chemical categories which: 1) Are listed at 40 CFR 372.65 pursuant to Section 313 of the Emergency Planning and Community Right-to-Know Act (EPCRA) (also known as Title III of the Superfund Amendments and Reauthorization Act (SARA) of 1986; 2) are present at or above threshold levels at a facility subject to EPCRA Section 313 reporting requirements; and 3) that meet at least one of the following criteria: (i) Are listed in Appendix D of 40 CFR 122 on either Table II (organic priority pollutants), Table III (certain metals, cyanides, and phenols) or Table V (certain toxic pollutants and hazardous substances); (ii) are listed as a hazardous substance pursuant to Section 311(b)(2)(A) of the CWA at 40 CFR 116.4; or (iii) are pollutants for which EPA has published acute or chronic water quality criteria.

-- Truck and rail car loading and unloading areas for liquid Section 313 water priority chemicals.

- These areas shall be operated to minimize discharges of Section 313 water priority chemicals. Protection such as overhangs or door skirts to enclose trailer ends at truck loading/unloading docks shall be provided as appropriate. Appropriate measures to minimize discharges of Section 313 chemicals may include: placement and maintenance of drip pans (including the proper disposal of materials collected in the drip pans where spillage may occur such as hose connections); a strong spill contingency and integrity testing plan; and/or other equivalent measures.

  -- Areas where Section 313 water priority chemicals are transferred, processed or otherwise handled.

- Processing equipment and materials handling equipment shall be operated so as to minimize the discharges of Section 313 water priority chemicals. Materials used in piping and equipment shall be compatible with the substances handled. Drainage from process and materials handling areas shall minimize storm water contact with Section 313 water priority chemicals. Additional protection such as covers or guards to prevent exposure to wind, spraying, or releases from pressure relief vents from causing a discharge of Section 313 water priority chemicals to the drainage system shall be provided as appropriate. Visual inspections or leak tests shall be provided for overhead piping conveying Section 313 water priority chemicals without secondary containment.

  -- For drainage originating from the above described areas, valves or other positive means should be used to prevent discharges or excessive leaks of Section 313 water priority chemicals. Where containment units are employed, such units may be emptied by pumps or ejectors; however, these shall be manually activated.

  Flapper-type drain valves must not be used to drain containment areas. Valves used for the drainage of containment areas should not be used to drain non-containment areas. Valves used should be of the open-and-closed design.

  If plant drainage is not engineered as above, the final discharge of all in-plant storm sewers should be equipped to be equivalent with a diversion system that could, in the event of an uncontrolled spill of a Section 313 water priority chemical, return the spilled material to the facility. Records shall be kept of the frequency and estimated volume (in gallons) of discharges from the containment areas.

  -- Records shall be kept of the frequency and estimated volume (in gallons) of discharges from containment areas.

  -- Other areas (other than those described above) of the facility from which runoff which may contain a Section 313 water priority chemical, or spills of Section 313 water priority chemicals could cause a discharge, shall incorporate the necessary drainage or other control features to prevent discharge of spilled or improperly disposed material and ensure the mitigation of pollutants in runoff or leachate.

- All areas of the facility shall be inspected at specific intervals for leaks or conditions that could lead to discharges of Section 313 water priority chemicals or direct contact of storm water with raw materials, intermediate materials, waste materials or products. In particular, plant piping, pumps storage tanks and bins, pressure vessels, process and materials handling equipment, and material bulk storage area shall be examined for any conditions or failures which could cause a discharge. Inspection shall include examination for leaks, wind blowing, corrosion, support or foundation failure, or other forms of deterioration or noncontainment. Inspection intervals shall be specified in the plan and shall be based on design and operational experience. Different areas may require different inspection intervals. Where a leak or other condition is discovered which may result in significant releases of Section 313 water priority chemicals to the drainage system, corrective action shall be taken. When a leak or noncontainment of a Section 313 water priority chemical has occurred, contaminated soil, debris, or other material must be promptly removed and disposed in accordance with this PPC Plan.
- Facility employees and contractor personnel using the facility shall be trained in and informed of preventive measures at the facility. Employee training shall be conducted at intervals specified in the plan, but not less than once per year, in matters of pollution control laws, and regulations and in the PPC Plan, and the particular features of the facility and its operation which are designed to minimize discharges of Section 313 water priority chemicals. The plan should designate a person who is accountable for spill prevention at the facility and who will set up the necessary spill emergency procedures and reporting requirements so that spills and emergency releases of Section 313 water priority chemicals can be isolated and contained before a discharge of a Section 313 water priority chemical can occur. Contractor or temporary personnel shall be informed of plant operation and design features in order to prevent discharges or spills from occurring.

If the installment of secondary containment structures or equipment listed above are not economically achievable at a facility, the PPC Plan should provide a spill contingency and integrity testing plan which provides a description of measures that ensure spills or other releases of toxic amounts of Section 313 water priority chemicals do not occur. The testing plan should contain the following:

- Detailed descriptions which demonstrate that secondary containment is not economically achievable;
- Description of response plans, personnel needs, and methods of mechanical containment such as the use or sorbents, booms collection devices, etc.); steps to be taken for removal of spilled Section 313 water priority chemicals; and access and availability of sorbents and other equipment;
- The testing component of the alternative plan must provide for conducting integrity testing of storage tanks at least once every five years, and

conducting integrity and leak testing of valves and piping a minimum every year; and

-- A written and actual commitment of manpower, equipment and materials required to comply with this permit and to expeditiously control and remove quantity of Section 313 water priority chemicals that may result in a toxic discharge.

- Provide a certification by a Registered Professional Engineer. The Professional Engineer shall certify that he or she has examined the facility and is familiar with the provisions in the PPC Plan and can attest that the PPC Plan has been prepared in accordance with good engineering practices. The Professional Engineer must recertify the PPC Plan once a year.

I. Certification Requirements for Non-Storm Water Discharges

- Provide a certification meeting the requirements of Part C, Section 3(a) of the industrial activities stormwater general permit (PAG #3) relating to the presence of non-stormwater discharges in the system.

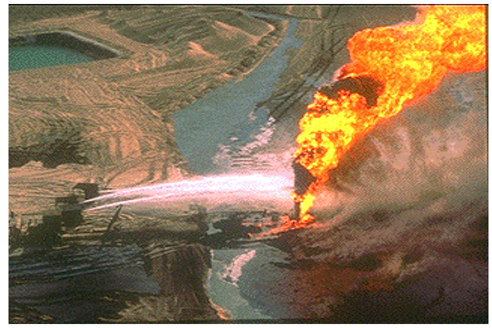
  If a facility does not have access to an outfall, manhole, or other point of access to the ultimate conduit which receives the discharge, this section of the plan shall indicate why the certification was not feasible. A discharge that is unable to provide the certification required by this paragraph must also then notify the Department within 180 days of the effective date of the general permit in accordance with Section A.3. of the permit.

J. Signatory Requirements

The PPC plan must be signed in accordance with the signatory requirements stipulated in the general permit.

John Wright Co.

Part 9-Firefighting. The mechanics of oil/gas fires, meltdown and secondary damage, water/chemical/explosive extinguishing methods and considerations for voluntary ignition



Coots Matthews, Consultant, Boots & Coots L.P.,
L. Flak, former Wright, Boots & Coots, employee.

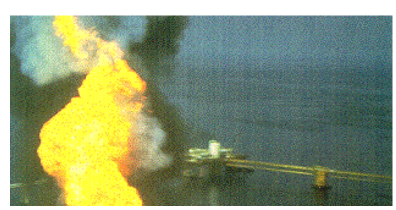
This article deals with the highly visible and potentially dangerous operations of extinguishing and capping burning blowouts. To understand the nature of oil and gas fires in blowout conditions, basic mechanics and terms are explained, and important features of meltdown and radiant heat exposure limits are discussed. Methods of extinguishing fire with water, chemicals and explosives are described, and examples of cap ping a well while it is burning are given. Finally, reasons for voluntarily igniting a blowout in high risk wells are presented.

INTRODUCTION

Surprisingly few surface blowouts ever ignite. Except in Kuwait, in 1991, less than 10 blow outs per year ever catch on fire, world wide. Typically, large formation water flows lifted by the hydrocarbon flow make ignition difficult if not impossible. Water cones into the blowout zone, drawn in by low flowing bottomhole pressure; or adjacent wet zones are exposed to the flow path.

Highly flammable blowouts may never ignite if no ignition source is present and flow is quickly dispersed. Thus, knowledgeable and experienced blowout specialists always restrict blowout access and carefully inspect the area around blowouts for ignition sources, particularly areas within an explosive vapor cloud. Failure to do this on a recent inland barge blowout in South Louisiana resulted in two deaths and other severe injuries.(1) "Victory awaits those who have everything in order-people call that luck. Defeat awaits those who don't- this they call bad luck." Roald Amundsen (leader of the first expedition to reach the South Pole)(2)

OIL AND GAS FIRE MECHANICS



Knowledge that hydrocarbons are highly flammable is common to our industry. Less well known are the explosive characteristics of hydrocarbon vapor-air mixtures and the dramatic impact of ignition of these mixtures on surrounding structures and personnel. To understand this risk, some ignition terms must be understood.

Flashpoint is the lowest temperature at which a material gives off enough flammable vapor to produce a momentary flash when exposed to a small flame. The flash point of gasoline is -43 deg. C (-45 deg. F), which is the reason it is considered highly flammable.

Spontaneous ignition temperature is the minimum temperature at which a material spontaneously ignites. Methane has a relatively high spontaneous ignition temperature of 537 deg. C (999 deg. F). This makes re-ignition of a methane fuel fire after extinguishment difficult. In practice, low-flash-point, low-spontaneous-ignition-temperature gas condensate blowouts present the greatest blowout ignition hazard.

Explosive limit of differing blowout flows varies with chemical composition. There is a minimum ratio of hydrocarbon vapor to air, below which ignition will not occur. Alternately, there is also a maximum ratio of hydrocarbon vapor to air, at which ignition will not occur. These limits are termed the lower and upper explosive limits. For gasoline vapor, the explosive range is from 1.3 to 6.0% vapor to air. For methane, this range is 5 to 15%. "Crude oil is a highly volatile, explosive cocktail which is lighter than water and burns twice as hot as coal. " (3) Vapor cloud explosion is possible through the following sequence:

- Hydrocarbons are released near wellhead
- Some gas liquids flash evaporate, forming an aerosol of liquid droplets and vapor
- Heavier hydrocarbon liquids that do not flash evaporate pool around well and release vapors
- Vapors mix with air and form a combustible vapor cloud
- An ignition source is exposed within this explosive mixture
- Combustion starts and a flame front propagates through the flammable zone.

Research has shown that speed of the flame front movement is directly proportional to the amount of blast over-pressure. High flame front speeds and resulting high blast over pressures are seen in situations where there is a significant amount of confinement and congestion that limits flame front expansion and increases flame turbulence.

Most vapor cloud explosions are deflagrations, not detonations. Flame speed of a deflagration is subsonic, with flame speed increasing in restricted areas and decreasing in open areas. Significantly, a detonation is supersonic, and will proceed through almost all of the available flammable vapor at the detonation reaction rate. This creates far more severe peak over-pressures and much higher amounts of blast energy (4).

Offshore rigs, production platforms and inland barges are at greatest risk. Hard-welded quarters and other enclosed areas are at particular risk as it is possible to get detonation in these confined areas.

MELTDOWN

The pressure-feed fire of a blowout will totally destroy the surrounding steel structure in minutes. Derricks have fallen-in less than 30 minutes after blowout ignition. The core temperature of a low-GOR 28 deg. F API crude oil blowout in Kuwait was measured at 1,677 deg. C (3,051 deg. F). And a radiant heat temperature of 510 deg. C (950 deg. F) was measured at ground level, 15 m (49 ft) from the base of this large vertical fire, which was estimated at 30,000 bopd. Oil well firefighters commonly see surrounding sand and stones melted and fused on large fires. Steel loses most of its strength at 500 deg. C (932 deg. F) and melts at 1,500 deg. C (2,732 deg. F).

Radiant heat. Common radiant heat exposure limits are:

- 0.5 KW/m2: Maximum working level for unprotected personnel
- 10.0 KW/m2: Maximum working level with protective equipment
- 15.0 KW/m2: Maximum working level for equipment.

On a very large Kuwait fire (about 30,000 bopd) the following heat radiations were recorded (upwind): 1.5 KW/m2 at 200 m (656 ft); 10.0 KW/m2 at 75 m (246 ft); and 15 KW/m2 at 35 m (115 ft). To understand the significance of these radiation levels, aluminized reflective fire entry suits are generally rated to only about the 15 KW/m2 radiation level. Oil well fire fighters commonly work inside the 15 KW/m2 level using Nomex long johns and hoods, heavy socks, insulated boots and heavy cotton outer wear, under a continuous water spray.

In Kuwait, maximum recording heat strips measured temperatures as high as 230¡C (446¡F) on the hard hats of firefighters. The one reason that they continue to use heavy aluminum hard hats is that common plastic oil field hard hats melt.

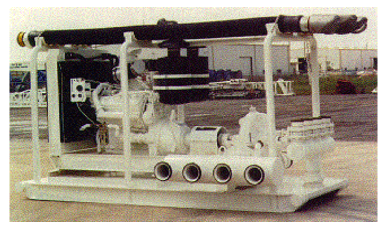


Fig. 23. Air-transportable fire pumps stocked by oil well firefighters.

Sufficient water application to a blowout greatly reduces heat impact on surrounding structures, Fig. 22. Radiant heat is effectively eliminated as a problem when sufficient water is pumped into the fire. Work in high heat radiation areas is obviously dangerous and should only be attempted by experienced oil well firefighters.

Secondary damage. Flammable fluid storage and gas handling systems can start a fire that leads to well blowouts, e.g., Piper Alpha. At Piper Alpha, it was established that the night shift had attempted to restart a pump, unaware that a key pressure safety valve had been removed during maintenance. The low-lying cloud of condensate resulting from the leak ignited and caused an initial explosion followed by a large crude oil fire.5 In the resulting disaster, 167 men lost their lives, but the relatively small blowouts from fire-damaged well heads had nothing to do with their deaths. Fires from improperly handled production streams and stored flammable liquid can be a greater fire risk and cause more damage than a blowout.

Emergency response plans must address how stored flammable fluids on an offshore platform are displaced with water and de-pressurized if a fire or well blowout occurs.

Fig. 25. Large land rig immediately after operator voluntarily ignited the gas well blowout due to H2S safety concerns.

EXTINGUISHMENT METHODS

Several methods are available to extinguish a blowout fire. Summarized here are the use of water, chemicals, explosives and an example of capping a well while it is burning.

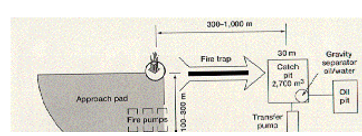


Fig. 24. Major rig fire water system designed for Kuwait Oil Co.

Water. The most important method to limit fire damage to structures from
a blowout fire is application of water. The common use of sprinkler heads and deluge nozzles in modern offshore production platforms has greatly reduced the risk of a Piper Alpha type tragedy. Yet, in land rig operations and older offshore moveable rigs and platforms, there is little or no water protection integral to the operation. Without modern fire water systems, blowout ignition is more likely, with probable total loss of rig or platform.

Water alone has extinguished some of the largest blowout fires experienced by our industry, once flow was directed vertically by firefighters. Water works to extinguish blowout fires by various means:

- It cools fire below spontaneous ignition temperature by absorbing heat as it is flashed to steam
- Water flashed to steam displaces oxygen and smothers fire
- Powerful water streams displace fuel from fire.

Main water use in blowout fire fighting is not to extinguish the fire, but to allow men and equipment to work near the fire. Early firefighters' efforts on burning blowouts involve removal of debris and working to get the fire burning vertically. Wells capped while burning may require more water than conventional extinguish-and-cap efforts.

Offshore marine vessels commonly have substantial firefighting capabilities, i.e., 10,000 gpm, with monitors mounted high on the vessel to allow water to reach even large plat forms. Fire pumps in inventory with oil well firefighters are smaller, air transportable systems, Fig. 23. These pumps provide 4,000 gpm at 250-psi head. Two of these pumps are used on a typical large fire on a land or inland barge rig. Oil well firefighters also inventory piping systems for these pumps that contain 4-in. aluminum water delivery pipe, fire monitors and associated equipment. One U pipe rack" is used typically with two pumps on a large onshore fire.

Modern derrick barges, MSVs, pipeline lay barges and large hydraulic dredge barges have been used offshore to support firefighting efforts. On land, common mobile fire pumps in use with civilian fire departments have been used on small fires. These truck-mounted pumps can provide 1,500 to 3,000 gpm, but require greater care and may present associated problems in coordinating with civilian firefighters.

Onshore water requirements depend greatly on the nature of the fire, but most blowouts would be adequately handled with the system out lined in Fig. 24. This system is similar to that used for all firefighters in Kuwait in 1991, and was designed by the authors for Kuwait Oil Co. in December 1990, prior to any Kuwaiti blowout. Note use of the fire trap between run-off and re-circulation pits to allow safe recovery of produced oil, and fire water recycling.

Produced water can be added to Fire water systems to reduce external water supply needs. Multiple water wells can be used with trucked-in water if no near-surface water supply is available.

Firefighters inventory high volume, low-head transfer pumps if water must be moved some distance from the f'ire. A water supply of about 9 bpm is adequate for most fires, given sufficient surface storage, 24-hr delivery and recycling.

On critical wells near populated areas or other facilities, or in remote areas, emergency response plans should consider sourcing the water supply and whether a deluge system should he incorporated in drilling plans.

Chemicals. Foam and dry chemicals have been used in limited roles in oil well firefighting. Foam consists of water, foam concentrate and air. It is used on liquid hydrocarbon fires to smother the fuel surface (excludes oxygen), suppress vapor emissions (explosive vapor release is restricted), generate steam (removes heat and displaces oxygen), cool surface (heat absorption) and reflect radiant heat. Use on blowouts is restricted to gas condensate fires and oil wells where lateral flow has led to a large fire-surface area.

Foam can help contain fire near the source and allow work near the flow source. Generally, water alone is adequate for this, but with large, low velocity, lateral oil flow, foam may be required. Modern firefighting foam such as 3M Lightwater ATC is commonly used with the William's Hydro Foam nozzle. This self-proportioning nozzle, when used with the ATC foam, allows foam to be thrown farther. Nozzles are available to handle up to 6,000 gpm, but the 2,000-bpm nozzle is most used on oil well fires.

Dry chemical extinguishers work like water, but principally act as a smothering agent. Common compounds used are sodium bicarbonate, Purple K (potassium bicarbonate base) and Monnex (highest efficiency rating). Use is generally on methane well fires where explosives cannot be used and water supply is inadequate. The main problem is that these systems are "one shot" devices that can not be topped up or refilled during application. The largest systems commonly available have 68 kg of powder in storage.

In Kuwait, extremely large (1,350 kg) dry chemical extinguishers from Ansul were used with Purple K powder as part of a mobile firefighting system used on smaller fires. Also used for the first time in Kuwait was the new William's Hydro-Chem nozzle that allows one nozzle to be used for water, foam and dry chemical. This would allow 1) using one nozzle to start water cool down, 2) adding foam to knock out the liquid fire, and finally 3) injecting dry chemical to knock down the remaining gas fire. Use in blowout fire fighting will be limited, but this new nozzle has good potential in industrial applications.

Explosives. Commonly available explosives such as 80% nitroglycerin grade dynamite are still used in oil well firefighting. It is believed that M. M. Kinley invented the presently used method, which was employed by experienced firefighters in the 1920s. For the mechanism, slow-speed photography indicates that the explosion acts to temporarily drive fuel away from the point where the flame develops and deprive that immediate area of oxygen to support instant reignition. Depending on fire size and prior experience, up to 500 lb of explosive may be used.

Explosives are used today in con junction with water to cool the shot and prevent reignition, when water supply or pump capability is insufficient to extinguish fire alone. As in any firefighting effort, all ignition sources must be removed from the well area prior to making the shot.

Typically, a smaller lube oil drum is used and packed with explosive. This drum is detonated using detonating cord run through the athey wagon boom. The cord is electrically detonated at the front of the athey wagon, some 60 to 70 ft away from the explosive drum. Heat insulating, silicon based cloth and water spray are used to protect the explosives from the fire. There is little risk of premature explosion as hot spots would only lead to non-detonation, and the explosives would burn up in the fire.

This is, interestingly, the lowest cost fire fighting technique, as the cost of a shot may be less than $2,000. This is exceeded by one recharge of the large Ansul dry chemical extinguisher and just a few drums of ATC foam concentrate. Less-experienced firefighters tend to discount the use of explosive shots only because of their lack of knowledge in the method, not because of any legitimate safety or economic reason.

Killing flow with well on fire. Recently, a blowout in inland waters was capped while burning by Boots & Coots to limit environmental dam age and for added safety. This technique has also been used on an H2S blowout in Canada after Boots & Coots replaced a company that lost two men during conventional capping attempts.6 The basic method involves using conventional capping stacks, as will be described next month, but equipping the capping BOPs with heat shielding and water deluge to limit high temperature exposure. Once the BOPs are over the flow and burning is underway above the riser tube, flow within the capping stack helps protect the BOPs. Wells have been stung, as will be discussed next month, while on fire to kill both flow and fire.

VOLUNTARY IGNITION

H2S hazard has led operators to voluntarily ignite a blowout for safety. Fig. 25 is a spectacular picture of a 30% H2S blowout (>50 MMcfd) taken immediately after ignition by a flare gun. Interestingly, no more than 2 ppm SO2 could ever be detected at ground level in the plume from this fire. Most operators that are planning these types of high-risk wells have plans that leave blowout ignition choice up to the field personnel. Two reasons for considering voluntary ignition are discussed here.

Pollution. This potential problem has not yet-to the authors' knowledge-led an operator to voluntarily ignite a blowout. However, after natural ignition, major efforts have been taken to keep the fire burning to lessen pollution. There is little question that a burning blowout presents less long-term environmental dam age than a well spewing oil unchecked into a marine estuary. And recent experiences have indicated that voluntary ignition of a rig, or particularly an inland barge, may be the less-expensive option, considering the cost of environmental dam age and clean-up.

Operators have spent more money on clean-up than was spent on blowout control. Yet, ignition of an oil well blowout on a major offshore plat form would tremendously complicate control efforts and likely result in total platform loss. A small land rig or inland barge rig represents less capital investment and easier removal of fire damaged debris. Difficult legal and insurance questions must be answered before an operator can determine its policy.

Safety. This consideration is a major concern in the blowout control business. Unexpected vapor cloud ignition resulted in the only deaths (two) and lost time injuries (six) seen by firefighters in Kuwait-all by inexperienced firefighting teams. With the recent deaths of two men in Louisiana and near misses seen over the years, consideration should be given to igniting some blowouts for safety. This is an easier choice if there is H2S present, significant pollution potential, or close proximity to civilian population. Blowout work is safer on burning wells. In many cases, operators and firefighters in hindsight wished that they had opted for voluntary ignition from the start, rather than suffer the consequences of an unexpected ignition.

On critical wells of higher risk, operators should consider whether voluntary ignition should be part of the emergency response plan and, if so, instructions and flare guns should be made available to wellsite personnel. *"We judge ourselves by our policies. Others judge us by our actions" Anon.*

Coming Next

Blowout surface intervention methods. Equipment and methods used to control blowout flow at surface will be reviewed. These include conventional capping with wellhead and BOPs, use of slip rams in capping stacks, tree and BOP replacement, stinging, junk shots, hot tapping, freezing and induced well bridging. Use of snubbing units on diverted blowouts will be discussed.

Next Article

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The authors

Coots Matthews is a consultant for Boots & Coots L.P. He began his oil field career with Halliburton in 1947, and later, in 1947, he joined the M. M. Kinley Co., where he worked with Boots Hansen and Red Adair to pioneer the methods used in firefighting and blowout control today. In 1959, he began working at the Red Adair Co.; and in 1978, he co-founded Boots & Coots. He has worked on more than 1,000 blowout control projects in his career which spans five decades.

L. Flak is a former John Wright Company employee.

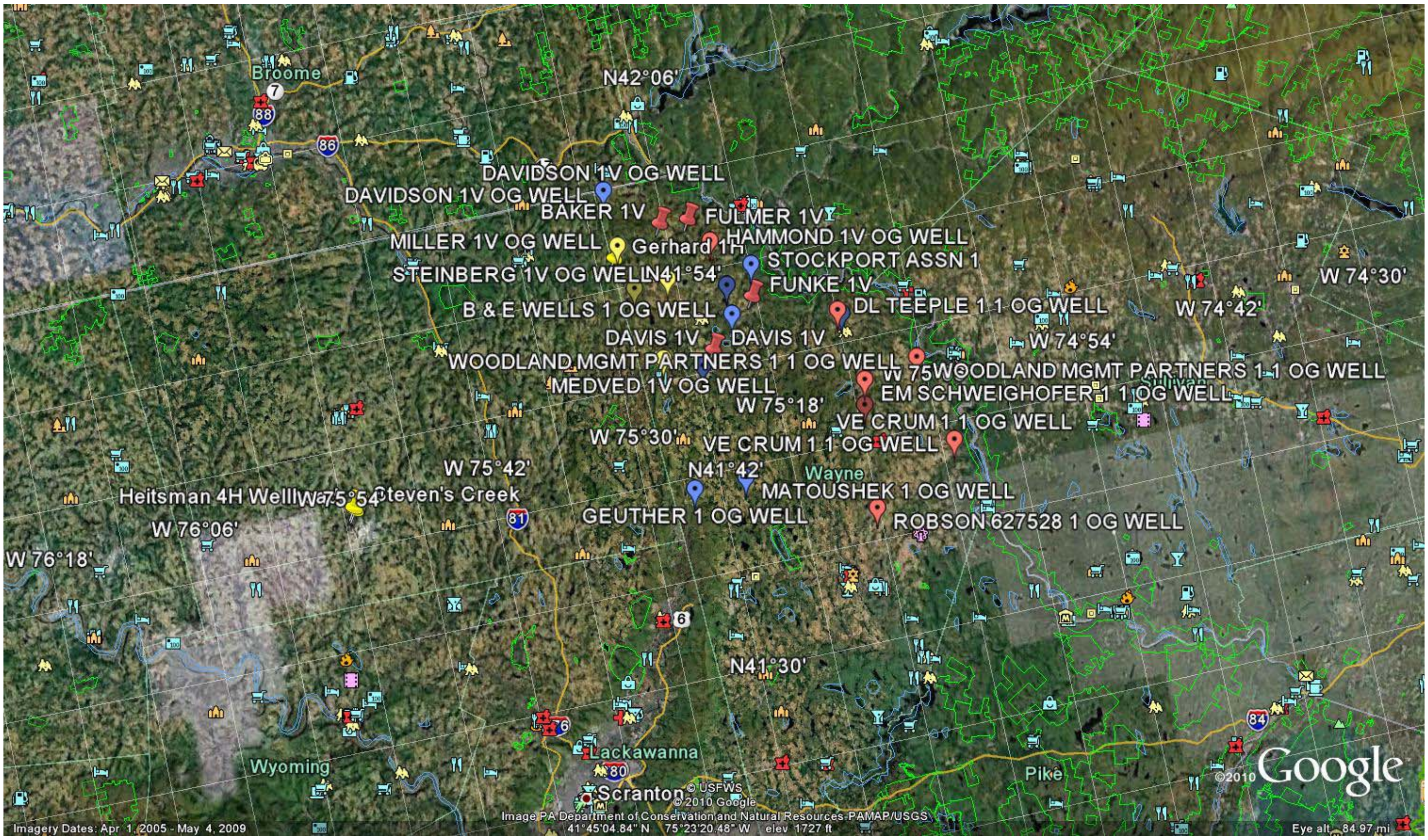
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Image PA Department of Conservation and Natural Resources-PAMAP/USGS
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Imagery Dates: Apr 1, 2005 - May 4, 2009
41°45'04.84" N 75°23'20.48" W elev 1727 ft
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ANNEX 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

Subchapter A. GENERAL PROVISIONS

§ 78.1. Definitions.

(a) The words and terms defined in section 103 of the act (58 P. S. § 601.103), section 2 of the Coal and Gas Resource Coordination Act (58 P. S. § 502), section 2 of the Oil and Gas Conservation Law (58 P. S. § 402), section 103 of the Solid Waste Management Act (35 P. S. § 6018.103) and section 1 of The Clean Stream Law (35 P. S. § 691.1), have the meanings set forth in those statutes when the terms are used in this chapter.

(b) The following words and terms, when used in this chapter, have the following meanings, unless the context clearly indicates otherwise:

* * * * *

Casing seat—The depth to which [**~~the surface casing or coal protection~~**] casing **[is run] [~~or intermediate casing~~] is set.** [~~In wells without surface casing, the~~ **~~surface~~** ~~casing seat shall be~~ **~~considered to be~~** ~~equal to~~ **~~50 feet below the deepest fresh groundwater~~ [~~the depth of casing which is normal for wells in the area~~]**.

* * * * *

Cement—A mixture of materials for bonding or sealing that attains a 7-day maximum permeability of 0.01 millidarcies and a 24-hour compressive strength of at least 500 psi in accordance with applicable **[API]** standards and specifications.

***Cement job log* – a written record that documents the actual procedures and specifications of the cementing operation. [~~The record must include the type of cement with additives, the volume, yield and density in pounds per gallon of the cement and the amount of cement returned to the surface, if any. Cementing procedural information must include a description of the pumping rates in bbls per minute, pressures in psi, time in minutes and sequence of events during the cementing operation.~~]**

*   *   *   *   *

***Conductor pipe* – a short string of large-diameter casing used to stabilize the top of the wellbore in shallow unconsolidated formations.**

*   *   *   *   *

***Intermediate casing* – a string of casing SET AFTER THE SURFACE CASING AND BEFORE [~~other than~~] production casing, NOT TO INCLUDE COAL PROTECTION CASING, that is used in the wellbore to isolate, stabilize or provide well control. [~~to a greater depth than that provided by the surface casing or coal protection casing.~~]**

*   *   *   *   *

L.E.L.— LOWER EXPLOSIVE LIMIT

*   *   *   *   *

[*Retrievable*—When used in conjunction with surface casing, coal protective casing or production casing, the casing that can be removed after exerting a prudent effort to pull the casing while applying a pulling force at least equal to the casing weight plus 5000 pounds or 120% of the casing weight, whichever is greater.]

*   *   *   *   *

Surface Casing—**[A string of pipe which extends from the surface and that segregates and protects fresh groundwater and stabilizes the hole.][~~ Casing~~] A STRING OR STRINGS OF CASING used to isolate the wellbore from fresh groundwater and to prevent the escape or migration of gas, oil [~~and~~] OR other fluids from the wellbore into fresh groundwater. The surface casing is also commonly referred to as the water string or water casing.**

*   *   *   *   *

UNCONVENTIONAL FORMATIONS – FORMATIONS THAT TYPICALLY PRODUCE GAS THROUGH THE USE OF ENHANCED DRILLING OR COMPLETION TECHNOLOGIES SUCH AS THE RHINESTREET, BURKET, MARCELLUS, MANDATA AND UTICA SHALE FORMATIONS, OR OTHER FORMATIONS IDENTIFIED BY THE DEPARTMENT.

Subchapter C. ENVIRONMENTAL PROTECTION

PERFORMANCE STANDARDS

§ 78.51. Protection of water supplies.

(a) A well operator who affects a public or private water supply by pollution or diminution shall restore or replace the affected supply with an alternate source of water adequate in quantity and quality for the purposes served by the supply **as determined by the Department**.

* * * * *

(d) **[The operator shall affirmatively demonstrate to the Department's satisfaction that the quality of the restored or replaced water supply to be used for human consumption is at least equal to the quality of the water supply before it was affected by the operator. If the quality of the water supply before it was affected by the operator cannot be affirmatively established, the operator shall demonstrate that the concentrations of substances in the restored or replaced water supply do not exceed the primary and secondary maximum contaminant levels established under § 109.202 (relating to State MCLs and treatment technique requirements).] A restored or replaced water supply shall include any well, spring, public water system or other WATER supply approved by the Department, which meets the criteria for adequacy as follows:**

(1) ***Reliability, cost, maintenance and control.*** **A restored or replaced water supply, at a minimum, must:**

(i) Be as reliable as the previous water supply.

(ii) Be as permanent as the previous water supply.

(iii) Not require excessive maintenance.

(iv) Provide the [~~owner and the~~] WATER user with as much control and accessibility as exercised over the previous water supply.

(v) Not result in increased costs to operate and maintain. If the operating and maintenance costs of the restored or replaced water supply are increased, the operator shall provide for permanent payment of the increased operating and maintenance costs of the restored or replaced water supply.

(2) ***Quality.*** **The quality of a restored or replaced water supply will be deemed adequate if it meets the standards established pursuant to the Pennsylvania Safe Drinking Water Act (35 P. S. § § 721.1—721.17), or is comparable to the [~~unaffected~~] THE QUALITY OF THE water supply BEFORE IT WAS AFFECTED BY THE OPERATOR if that water supply did not meet these standards.**

(3) A*dequate quantity*. A restored or replaced water supply will be deemed adequate in quantity if it meets one of the following as determined by the Department:

(i) It delivers the amount of water necessary to satisfy the water user's needs and the demands of any reasonably foreseeable uses.

(ii) It is established through a connection to a public water supply system [~~which~~] THAT is capable of delivering the amount of water necessary to satisfy the water user's needs and the demands of any reasonably foreseeable uses.

(iii) For purposes of this paragraph and with respect to agricultural water supplies, the term reasonably foreseeable uses includes the reasonable expansion of use where the water supply available prior to drilling exceeded the actual use.

(4) *Water source serviceability*. Replacement of a water supply includes providing plumbing, conveyance, pumping or auxiliary equipment and facilities necessary for the [~~surface landowner or water purveyor~~] WATER USER to utilize the water supply.

(e) If the water supply is for uses other than human consumption, the operator shall demonstrate to the Department's satisfaction that the restored or replaced water supply is adequate for the purposes served by the supply.

(f) **[The oil or gas well operator's duty to replace or restore a water supply includes providing plumbing, conveyance, pumping or auxiliary equipment and facilities necessary for the surface landowner or water purveyor to utilize the water supply.]**

[(g)] Tank trucks or bottled water are acceptable only as temporary water replacement for a period approved by the Department and do not relieve the operator of the obligation to provide a restored or replaced water supply.

[(h)] **(g)** If the well operator and the [~~**landowner, water purveyor or affected person**~~] **WATER USER** are unable to reach agreement on the means for restoring or replacing the water supply, the Department or either party may request a conference under section 501 of the act (58 P. S. § 601.501).

(h) A well operator who receives notice from a landowner, water purveyor or affected person that a water supply has been affected by pollution or diminution, shall report receipt of [~~such~~] notice FROM AN AFFECTED PERSON to the Department within [~~10 calendar days~~] 24 HOURS of receiving the notice.

§ 78.52**.** Predrilling or prealteration survey**.**

(a) A well operator who wishes to preserve its defense under section 208(d)(1) of the act (58 P. S. § 601.208(d)(1)) that the pollution of a water supply existed prior to the drilling or alteration of the well shall **[cause]** **conduct** a predrilling or prealteration survey **[to be conducted]** in accordance with this section.

* * * * *

(d) An operator electing to preserve its defenses under section 208(d)(1) of the act shall provide a copy of the results of the survey to the Department and the landowner or water purveyor within 10-[~~**calendar**~~] **BUSINESS** days of **receipt** **[being notified by the Department to submit a copy]** of the results. **TEST RESULTS NOT RECEIVED BY THE DEPARTMENT WITHIN 10 BUSINESS DAYS MAY NOT BE USED TO PRESERVE THE OPERATOR'S DEFENSES UNDER SECTION 208(D)(1) OF THE ACT.**

* * * * *

§ 78.55. Control and disposal plan.

(a) Prior to generation of waste, the well operator shall prepare and implement a plan under § 91.34 (relating to activities utilizing pollutants) for the control and disposal of fluids, residual waste and drill cuttings, including tophole water, brines, drilling fluids, additives, drilling muds, stimulation fluids, well servicing fluids, oil, production fluids and drill cuttings from the drilling, alteration, production, plugging or other activity associated with oil and gas wells.

(b) The plan shall identify the control and disposal methods and practices utilized by the well operator and be consistent with the act, The Clean Streams Law (35 P. S. § § 691.1—691.1001), the Solid Waste Management Act (35 P. S. § § 6018.101—6018.1003) and § § 78.54, 78.56—78.58 and 78.60—78.63. **THE PLAN SHALL ALSO INCLUDE A PRESSURE BARRIER POLICY THAT IDENTIFIES BARRIERS TO BE USED DURING IDENTIFIED OPERATIONS.**

(c) The operator shall revise the plan prior to implementing a change to the practices identified in the plan.

(d) A copy of the plan shall be provided to the Department upon request **AND SHALL BE AVAILABLE AT THE WELL SITE DURING DRILLING AND COMPLETION ACTIVITIES FOR REVIEW**.

(E) A LIST OF EMERGENCY CONTACT PHONE NUMBERS FOR THE AREA IN WHICH THE WELL SITE IS LOCATED MUST BE INCLUDED IN THE PLAN AND BE PROMINENTLY DISPLAYED AT THE WELL SITE DURING DRILLING, COMPLETION OR ALTERATION ACTIVITIES.

Subchapter D. WELL DRILLING, OPERATION AND PLUGGING

GENERAL

Sec.

CASING AND CEMENTING

OPERATING WELLS

* * * * *

Subchapter D. WELL DRILLING, OPERATION AND PLUGGING

GENERAL

§ 78.71. Use of safety devices—well casing.

(a) The operator shall equip the well with one or more strings of casing of sufficient **cemented** length and strength to **attach [~~blow-out prevention~~] PROPER WELL CONTROL equipment and** prevent blowouts, explosions, fires and casing failures during installation, completion and operation.

* * * * *

§ 78.72. Use of safety devices—blow-out prevention equipment.

(a) The operator shall use blow-out prevention equipment **AFTER SETTING CASING WITH A COMPETENT CASING SEAT[when well head pressures or natural open flows are anticipated at the well site that may result in a blow-out or when the operator is drilling in an area where there is no prior knowledge of the pressures or natural open flows to be encountered.] in the following circumstances:**

> **(1) When drilling a well that is intended to produce natural gas from [the Marcellus Shale] AN UNCONVENTIONAL formation;**
>
> **(2) WHEN DRILLING OUT SOLID CORE HYDRAULIC FRACTURING PLUGS TO COMPLETE A WELL;**
>
> **(2) When well head pressures or natural open flows are anticipated at the well site that may result in a loss of well control;**
>
> **(3) When the operator is drilling in an area where there is no prior knowledge of the pressures or natural open flows to be encountered;**
>
> **(4) On wells regulated by the Oil and Gas Conservation Law (58 P.S. §§ 401 – [~~409~~] 419);**
>
> **(5) When drilling within 200 feet of a building.**

(b) Blow-out prevention equipment used shall be in good working condition at all times.

(c) Controls for the blow-out preventer shall be accessible to allow actuation of the equipment. Additional controls for a blow-out preventer with a pressure rating of

greater than 3,000 psi, not associated with the rig hydraulic system, shall be located AT LEAST 50 FEET away from the drilling rig such that the blow-out preventer can be actuated if control of the well is lost.

[(c)] **(d)** * * * * *

[(d)] **(e)** The operator shall conduct a complete test of the ram type blow-out preventer and related equipment for both pressure and ram operation before placing it in service on the well. The operator shall test the annular type blow-out preventer in accordance with the manufacturer's published instructions, or the instructions of a professional engineer, prior to the device being placed in service. **Blow-out prevention equipment that fails the test shall not be used until it is repaired and passes the test.**

[(e)] **(f)** When the equipment is in service, the operator shall visually inspect blow-out prevention equipment during each tour of drilling operation and during actual drilling operations test the pipe rams for closure daily and the blind rams for closure on each round trip. When more than one round trip is made in a day, one daily closure test for blind rams is sufficient. Testing shall be conducted in accordance with American Petroleum Institute publication API RP53, ''API Recommended Practice for Blowout Prevention Equipment Systems for Drilling Wells.''**, OR OTHER PROCEDURE APPROVED BY THE DEPARTMENT**. The operator shall record the results of the inspection and closure test in the drillers log before the end of the tour. **IF blow-out prevention equipment [~~that~~] is not in good working order, DRILLING SHALL CEASE WHEN CESSATION OF DRILLING CAN BE ACCOMPLISHED SAFELY AND NOT RESUME UNTIL THE BLOW-OUT PREVENTION EQUIPMENT IS [~~shall be~~] repaired or replaced [~~immediately~~] and re-tested. [~~prior to the resumption of drilling.~~]**

(g) All lines, valves and fittings between the closing unit and the blow-out preventer stack shall be flame resistant and have a rated working pressure that meets or exceeds the requirements of the blow-out preventer system.

[(f)] **(h)** [~~**During drilling when conditions are such that the use of a blowout preventer can be anticipated**~~] **WHEN A BLOWOUT PREVENTER IS INSTALLED OR REQUIRED PURSUANT TO SUBSECTION (A)**, there shall be present on the **[rig floor a certified]** **well site an** individual **[responsible to]** **[~~who the operator has determined is trained and competent in the use of the blow-out prevention equipment.~~** ~~Satisfactory completion of~~ **~~[a United States Geologic Survey (U.S.G.S.)]~~** ~~a~~**[~~n approved~~]** **WITH A CURRENT CERTIFICATION FROM A** well control course **ACCREDITED by the** **[American Petroleum Institute,]** [**~~Independent~~]** **INTERNATIONAL Association of Drilling Contractors** **OR OTHER ORGANIZATION APPROVED BY THE DEPARTMENT. THE CERTIFICATION SHALL BE AVAILABLE FOR REVIEW AT THE WELL SITE. THE DEPARTMENT SHALL MAINTAIN A LIST OF APPROVED**

ACCREDITING ORGANIZATIONS ON ITS WEBSITE. [~~or equivalent study shall be deemed adequate~~ ~~**[certification]**~~ ~~for purposes of this subsection.~~]

(I) WELL DRILLING AND COMPLETION OPERATIONS REQUIRING PRESSURE BARRIERS, AS IDENTIFIED BY THE OPERATOR PURSUANT TO 25 PA. CODE § 78. 55(B), SHALL EMPLOY AT LEAST TWO MECHANICAL PRESSURE BARRIERS BETWEEN THE OPEN PRODUCING FORMATION AND THE ATMOSPHERE THAT ARE CAPABLE OF BEING TESTED. THE MECHANICAL PRESSURE BARRIERS SHALL BE TESTED ACCORDING TO MANUFACTURER SPECIFICATIONS PRIOR TO OPERATION. IF DURING THE COURSE OF OPERATIONS THE OPERATOR ONLY HAS ONE FUNCTIONING BARRIER, OPERATIONS MUST CEASE UNTIL ADDITIONAL BARRIERS ARE ADDED AND TESTED OR THE REDUNDANT BARRIER IS REPAIRED AND TESTED. STRIPPER RUBBER OR A STRIPPER HEAD SHALL NOT BE CONSIDERED A BARRIER.

(J) A COILED TUBING RIG OR A HYDRAULIC WORKOVER UNIT WITH APPROPRIATE BLOWOUT PREVENTION EQUIPMENT MUST BE EMPLOYED DURING POST COMPLETION CLEANOUT OPERATIONS IN HORIZONTAL UNCONVENTIONAL FORMATIONS.

[(g)] (k) The minimum amount of **INTERMEDIATE** [~~cemented~~] casing **THAT IS CEMENTED TO THE SURFACE** to which blow-out prevention equipment may be attached, shall be in accordance with the following:

Proposed Total ***VERTICAL*** *Depth (in feet)*	*Minimum Cemented Casing Required (in feet of casing cemented)*
Up to 5,000	400
5,001 to 5,500	500
5,501 to 6,000	600
6,001 to 6,500	700
6,501 to 7,000	800
7,001 to 8,000	1,000
8,001 to 9,000	1,200
9,001 to 10,000	1,400
Deeper than 10,000	1,800

[(h)] (l) * * * * *

§ 78.73. General provision for well construction and operation.

(a) The operator shall construct and operate the well in accordance with this chapter and ensure that the integrity of the well is maintained and health, safety, environment and property are protected.

[(a)] **(b)** The operator shall prevent gas **[and other fluids from lower formations from entering fresh groundwater.]**, **oil, brine, completion and servicing fluids, and any other fluids OR MATERIALS from below the casing seat from entering fresh groundwater, and SHALL OTHERWISE prevent pollution or diminution of fresh groundwater.**

[(b)] **(c)** After a well has been completed, recompleted, reconditioned or altered the operator shall prevent **SURFACE** shut-in pressure **[or]** **and** **SURFACE** producing back pressure [at] **INSIDE** the surface casing [**~~seat,~~**]**~~[or]~~** coal protective casing [**~~seat or intermediate casing seat when the intermediate casing is used in conjunction with the surface casing to isolate fresh groundwater~~**] from exceeding **THE FOLLOWING PRESSURE: 80 percent (80%) [**~~of the hydrostatic pressure of the surrounding fresh groundwater system in accordance with the following formula. The maximum allowable shut-in pressure [or] and producing back pressure to be exerted at the [surface casing seat, or coal protective] casing seat may not exceed the [hydrostatic] pressure calculated as follows: Maximum pressure = (0.8 x 0.433 psi/foot) multiplied by (casing length in feet).~~] **MULTIPLIED BY 0.433 PSI PER FOOT MULTIPLIED BY THE CASING LENGTH (IN FEET) OF THE APPLICABLE CASING.**

[**(c)]** **(d)** After a well has been completed, recompleted, reconditioned or altered, if the **SURFACE** shut-in pressure or **SURFACE** producing back pressure exceeds the **[hydrostatic]** pressure [**~~at the surface casing seat, coal protective casing~~**] as calculated in subsection **[(b)]** **(c)**, the operator shall take action to prevent the migration of gas and other fluids from lower formations into fresh groundwater. To meet this standard the operator may cement or install on a packer sufficient intermediate or production casing or take other actions approved by the Department. This section does not apply during testing for mechanical integrity in accordance with State or Federal requirements.

(e) Excess gas encountered during drilling, completion or stimulation shall be flared, captured or diverted away from the drilling rig in a manner that does not create a hazard to the public health or safety.

(f) Except for gas storage wells, the well must be equipped with a check valve to prevent backflow from the pipelines into the well.

* * * * *

§ 78.75a. Area of alternative methods.

(a) The Department may designate an area of alternative methods if the Department determines that well drilling requirements beyond those provided in this chapter

<u>are necessary to drill, operate or plug a well in a safe and environmentally protective manner.</u>

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

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

§ 78.76. Drilling within a gas storage reservoir area.

(a) An operator proposing to drill a well within a gas storage reservoir area or a reservoir protective area to produce gas or oil shall forward by certified mail a copy of the well location plat, the drilling, casing and cementing plan and the anticipated date drilling will commence to the gas storage reservoir operator **<u>and to the Department for approval by the Department</u>** and shall submit proof of notification **<u>TO THE GAS STORAGE RESERVOIR OPERATOR</u>** to the Department with the well permit application.

* * * * *

CASING AND CEMENTING

* * * * *

[(c) Casing and cementing standards in § § 78.83—78.85 (relating to surface and coal protective casing and cementing procedures; casing standards; and cement standards) apply to surface casing and coal protective casing but do not apply to production casing.]

§ 78.82 Use of conductor pipe**.**

If the operator installs conductor pipe in the well, the **[operator may not remove the pipe]** **<u>following provisions shall apply:</u>**

(i) **<u>The operator may not remove the pipe;</u>**
(ii) **<u>Conductor pipe shall be installed in a manner that prevents THE SUBSURFACE infiltration of surface water or fluids [~~from the operation into~~] [~~groundwater~~] BY EITHER DRIVING THE PIPE</u>**

INTO PLACE OR CEMENTING THE PIPE FROM THE SEAT TO THE SURFACE;

(iii) **Conductor pipe must be made of steel unless a different material is approved for use by the Department.**

§ 78.83. Surface and coal protective casing and cementing procedures.

(a) For wells drilled, altered, reconditioned or recompleted after [effective date], surface casing or any casing functioning as a water protection casing must not be utilized as production casing unless one of the following applies:

(1) **In oil wells where the operator does not produce any gas generated by the well and the annulus between the surface casing and the production pipe is left open;**

(2) **The operator demonstrates that the pressure in the well [~~bore at the casing seat~~] is no greater than the pressure permitted by § 78.73(c), [~~and~~] demonstrates through a pressure test or other method approved by the Department that all gas and fluids will be contained within the well, AND INSTALLS A WORKING PRESSURE GAUGE THAT CAN BE INSPECTED BY THE DEPARTMENT.**

[(a)] **(b)** If the well is to be equipped with threaded and coupled casing, the operator shall drill a hole so that the diameter is at least 1 inch greater than the outside diameter of the casing collar to be installed. If the well is to be equipped with plain-end welded casing, the operator shall drill a hole so that the diameter is at least 1 inch greater than the outside diameter of the **[casing tube]** [~~centralizer band~~] **CASING COUPLING**.

[(b)] **(c)** **[Except as provided in subsection (c) , t]T**he operator shall drill to approximately 50 feet below the deepest fresh groundwater or at least 50 feet into consolidated rock, whichever is deeper, and immediately set and permanently cement a string of surface casing to that depth. **EXCEPT AS PROVIDED IN SUBSECTION (F), THE SURFACE CASING SHALL NOT BE SET MORE THAN 200 FEET BELOW THE DEEPEST FRESH GROUNDWATER EXCEPT IF NECESSARY TO SET THE CASING IN CONSOLIDATED ROCK. The surface hole shall be drilled using air, freshwater, or freshwater-based drilling fluid. PRIOR TO CEMENTING, THE WELLBORE SHALL BE CONDITIONED TO ENSURE AN ADEQUATE CEMENT BOND BETWEEN THE CASING AND THE FORMATION. The surface casing seat shall be set in consolidated rock. When drilling a new well or redrilling an existing well, the operator shall install at least one centralizer within 50 feet of the casing seat and then install a centralizer in intervals no greater than every 150 feet above the first centralizer.**

[(c) If no fresh groundwater is being utilized as a source of drinking water within a 1,000-foot radius of the well, the operator may set and permanently cement a single string of surface casing through all water zones, including fresh, brackish and salt

water zones. Prior to penetrating zones known to contain, or likely containing, oil or gas, the operator shall install and permanently cement the string of casing in a manner that segregates the various waters.]

* * * * *

(f) If additional fresh groundwater is encountered in drilling below the permanently cemented surface casing, the operator shall **DOCUMENT THE DEPTH OF THE FRESH GROUND WATER ZONE IN THE WELL RECORD AND** protect the additional fresh groundwater by installing and cementing a subsequent string of casing or other procedures approved by the Department to completely isolate and protect fresh groundwater. The string of casing may also penetrate zones bearing salty or brackish water with cement in the annular space being used to segregate the various zones. Sufficient cement shall be used to cement the casing **[~~at least 20 feet into the permanently cemented surface casing~~] TO THE SURFACE**. **THE OPERATOR SHALL INSTALL AT LEAST ONE CENTRALIZER WITHIN 50 FEET OF THE CASING SEAT AND THEN INSTALL A CENTRALIZER IN INTERVALS NO GREATER THAN, IF POSSIBLE, EVERY 150 FEET ABOVE THE FIRST CENTRALIZER.**

(g) The operator shall set and cement a coal protective string of casing through workable coal seams. The base of the coal protective casing shall be at least 30 feet below the lowest workable coal seam. **The operator shall install at least two centralizers. One centralizer shall be within 50 feet of the casing seat and the second centralizer shall be within 100 feet of the surface.**

(h) **Unless an alternative method has been approved by the Department in accordance with § 78.75 (relating to Alternative methods), [W]w**hen a well is drilled through a coal seam at a location where the coal has been removed **or when a well is drilled through a coal pillar**, the operator shall drill to a depth of at least 30 feet but no more than 50 feet deeper than the bottom of the coal seam. The operator shall set and cement a coal protection string of casing to this depth. The operator shall equip the casing with a cement basket or other similar device above and as close to the top of the coal seam as practical. The bottom of the casing shall be equipped with an appropriate device designed to prevent deformation of the bottom of the casing. The interval from the bottom of the casing to the bottom of the coal seam shall be filled with cement either by the balance method or by the displacement method. Cement shall be placed on top of the basket between the wall of the hole and the outside of the casing by pumping from the surface. If the operator penetrates more than one coal seam from which the coal has been removed, the operator shall protect each seam with a separate string of casing that is set and cemented or with a single string of casing which is stage cemented so that each coal seam is protected as described in this subsection. The operator shall cement the well to isolate workable coal seams from each other.

(i) If the operator sets and cements casing under subsection (g) or (h) and subsequently encounters additional fresh groundwater zones below the deepest cemented casing string installed, the operator shall protect the fresh groundwater by installing and cementing another string of casing or other method approved by the Department. Sufficient cement shall be used to cement the casing **[~~at least 20 feet into the surface or coal protective casing~~] TO THE SURFACE**. The additional casing string may also penetrate zones bearing brackish or salt water, but shall be run and cemented prior to penetrating a zone known to or likely to contain oil or gas**. THE OPERATOR SHALL INSTALL AT LEAST ONE CENTRALIZER WITHIN 50 FEET OF THE CASING SEAT AND THEN, IF POSSIBLE, INSTALL A CENTRALIZER IN INTERVALS NO GREATER THAN EVERY 150 FEET ABOVE THE FIRST CENTRALIZER.**

(j) If it is anticipated that cement used to permanently cement the surface casing can not be circulated to the surface a cement basket may be installed immediately above the depth of the **anticipated [last] lost** circulation zone. The casing shall be permanently cemented by the displacement method. Additional cement may be added above the cement basket, if necessary, by pumping through a pour string from the surface to fill the annular space. **FILLING THE ANNULAR SPACE BY THIS METHOD DOES NOT CONSTITUTE PERMANENTLY CEMENTING THE SURFACE OR COAL PROTECTIVE CASING PURSUANT TO 25 PA. CODE § 78.83B.**

§ 78.83a. Casing and cementing plan.

(a) The operator shall prepare and maintain a casing and cementing plan showing how the well will be drilled and completed. The plan must demonstrate compliance with this subchapter and include the following information:

(1) The anticipated depth and thickness of any producing formation, expected pressures, [~~and~~] anticipated fresh groundwater zones AND THE METHOD OR INFORMATION BY WHICH THE DEPTH OF THE DEEPEST FRESH GROUNDWATER WAS DETERMINED;

(2) Diameter of the [~~well bore~~] BOREHOLE;

(3) Casing type, whether the casing is new or used, depth, diameter, wall thickness and burst pressure rating;

(4) Cement type, yield, additives, and estimated amount;

(5) Estimated location of centralizers;

(6) PROPOSED BOREHOLE CONDITIONING PROCEDURES.

[~~(6)~~](7) Alternative methods or materials as required by the Department as a condition of the well permit.

(b) The plan must be available at the well site for review by the Department.

(c) Upon request, the operator shall provide a copy of the well-specific casing and cementing plan to the Department for review and approval.

(d) Any revisions to the plan made as a result of on-site modification shall be documented in the plan [~~by the operator~~] and be available for review by the Department. THE PERSON MAKING THE REVISIONS TO THE PLAN SHALL INITIAL AND DATE THE REVISIONS.

§ 78.83b. Casing and cementing – lost circulation.

(a) If cement used to permanently cement the surface or coal protective casing is not circulated to the surface despite pumping a volume of cement equal to or greater than 120% of the calculated annular space, the operator shall DETERMINE THE TOP OF THE CEMENT, notify the Department, and meet one of the following requirements AS APPROVED BY THE DEPARTMENT:

(1) Run an additional string of casing at least 50 feet deeper than the STRING WHERE CIRCULATION WAS LOST [~~surface casing~~] and cement the [~~second~~] ADDITIONAL string of casing back to the seat of the [~~surface or coal protective casing~~] STRING WHERE CIRCULATION WAS LOST and vent the annulus of the additional casing string to the atmosphere at all times unless closed for well testing or maintenance. Shut-in pressure on the casing seat of the [~~second~~] ADDITIONAL string of casing must not exceed the requirements of section 78.73(c).

(2) [~~If the additional string of casing is the~~] RUN production casing[~~, the operator shall~~] AND set the production casing on a packer in a competent formation below the [~~surface casing seat,~~] STRING WHERE CIRCULATION WAS LOST and vent the annulus of the production casing to the atmosphere at all times unless closed for well testing or maintenance.

(3) Run production casing at least to the top of the formation that is being produced and cement the production casing to the surface.

(4) RUN INTERMEDIATE AND PRODUCTION CASING AND CEMENT BOTH STRINGS OF CASING TO THE SURFACE.

[~~(4)~~] (5) Produce oil but not gas and leave the annulus between the surface casing and the production pipe open.

(B) IN ADDITION TO MEETING THE REQUIREMENTS OF SUBSECTION (A), THE OPERATOR MAY ALSO PUMP ADDITIONAL CEMENT THROUGH A POUR STRING FROM THE SURFACE TO FILL THE ANNULAR SPACE.

[~~(b) If cement used to permanently cement the surface or coal protective casing is not circulated to the surface, the Department may require the operator to determine the amount of casing that was cemented by logging or other suitable method.~~]

§ 78.83c. Intermediate and production casing.

[~~(a) Except as provided in § 78.72 (relating to Use of safety devices – blow-out prevention equipment), intermediate and production casing must be cemented according to this section.~~]

(A) PRIOR TO CEMENTING THE INTERMEDIATE AND PRODUCTION CASING, THE BOREHOLE, MUD AND CEMENT SHALL BE CONDITIONED TO ENSURE AN ADEQUATE CEMENT BOND BETWEEN THE CASING AND THE FORMATION.

[(b)] If the well is to be equipped with an intermediate casing, CENTRALIZERS SHALL BE USED AND the casing must be cemented TO THE SURFACE BY THE DISPLACEMENT METHOD. [~~from the casing seat to a point at least 500 feet above the seat. If any producing horizon is open to the wellbore above the casing seat, the casing must be cemented from the casing seat up to a point at least 500 feet above the top of the shallowest productive horizon, or to a point at least 200 feet above the shoe of the next shallower casing string that was set and cemented in the well.~~] GAS MAY BE PRODUCED OFF [~~The~~] THE intermediate casing [~~may be perforated to produce gas or oil~~ if a shoe test demonstrates THAT ALL GAS WILL BE CONTAINED WITHIN THE WELL [~~a pressure gradient greater than 0.465 psi/ft multiplied by casing length in feet~~] AND A RELIEF VALVE IS INSTALLED AT THE SURFACE THAT IS SET LESS THAN THE SHOE TEST PRESSURE. THE SHOE TEST PRESSURE SHALL BE RECORDED IN THE COMPLETION REPORT.

[(c)] Except as provided for in § 78.83 (relating to surface and coal protective casing and cementing procedures), each well must be equipped with production casing. The production string may be set on a packer or cemented in place. If the production casing is cemented in place, CENTRALIZERS SHALL BE USED AND cement must be placed by the displacement method with sufficient cement to fill the annular space [~~to the surface or~~] to a point at least 500 feet above [~~the production casing seat~~] TRUE VERTICAL DEPTH OR AT LEAST 200 FEET ABOVE THE UPPERMOST PERFORATIONS, WHICHEVER IS GREATER.

§ 78.84. Casing standards.

(a) The operator shall install casing that can withstand the effects of tension, and prevent **leaks,** burst and collapse during its installation, cementing and subsequent drilling and producing operations.

(b) [~~Surface~~] EXCEPT AS PROVIDED IN SUBSECTION (C), ALL casing must be a string of new pipe with [~~a~~] AN INTERNAL pressure rating that is at least 20 percent greater than the anticipated maximum pressure to which the [~~surface~~] casing will be exposed.

(c) Used casing may be approved for use as surface, intermediate or production casing but must be pressure tested after cementing and before continuation of drilling. A passing pressure test is holding the anticipated maximum pressure to which it will be exposed for 30 minutes with not more than a 10 percent decrease in pressure.

(d) New or used plain end casing, except when being used as [~~drive pipe,~~] conductor PIPE, [~~or as a casing string prior to setting and cementing surface casing,~~] that is welded together for use must meet the following requirements:

(1) **It must pass a pressure test by holding the anticipated maximum pressure to which the casing will be exposed for 30 minutes with not more than a 10 percent decrease in pressure. The operator shall notify the Department at least 24 hours before conducting the test. The test results shall be entered on the drilling log.**

(2) **It shall be welded using at least three passes with the joint cleaned between each pass.**

(3) **It shall be welded by a person trained and certified in the applicable American Petroleum Institute['s], AMERICAN SOCIETY OF MECHANICAL ENGINEERS, AMERICAN WELDING SOCIETY OR EQUIVALENT standard for welding casing and pipe or an equivalent training and certification program as approved by the Department. THE CERTIFICATION REQUIREMENTS OF THIS PARAGRAPH SHALL TAKE EFFECT [INSERT DATE – 6 MONTHS AFTER THE EFFECTIVE DATE]. A person with 10 or more years of experience welding casing as of [effective date] who registers with the Department within nine months of the effective date of this subsection is deemed to be certified.**

[(b) The operator shall equip the casing string with appropriate equipment to center the casing through the hole in fresh groundwater zones. This equipment is

not required when existing hole conditions such as caving or crookedness might cause loss of the well or result in a defective cement job.]

[(c)] **(e)** When casing through a workable coal seam, the operator shall install coal protective casing that has a minimum wall thickness of 0.23 inches.

(f) Casing which is attached to a blow-out preventer with a pressure rating of greater than 3,000 psi shall be pressure tested AFTER CEMENTING. A passing pressure test must be holding [~~120 percent of the highest expected working pressure of the casing string being tested,~~] THE ANTICIPATED MAXIMUM PRESSURE TO WHICH THE CASING WILL BE EXPOSED for 30 minutes with not more than a 10 percent decrease. Certification of the pressure test shall be confirmed by entry and signature of the person performing the test on the driller's log.

§ 78.85. Cement standards.

(a) **When cementing surface casing[~~,~~] OR coal protective casing [~~and intermediate casing when the intermediate casing is used in conjunction with the surface casing to isolate fresh groundwater~~],** **[**T**]t**he operator shall use cement that **[will resist degradation by chemical and physical conditions in the well.] meets or exceeds the ASTM International C 150, Type I, II or III Standard or API Specification 10. The cement must also:**

(1) Secure the casing in the wellbore;

(2) Isolate the wellbore from fresh groundwater;

(3) Contain any pressure from drilling, completion and production;

(4) [~~Protect the casing from corrosion;~~

~~(5) Resist degradation by the chemical and physical conditions in the well;~~]

PROTECT THE CASING FROM CORROSION FROM, AND DEGRADATION BY, THE GEOCHEMICAL, LITHOLOGIC AND PHYSICAL CONDITIONS OF THE SURROUNDING WELLBORE. FOR WELLS EMPLOYING COAL PROTECTIVE CASING, THIS INCLUDES, BUT IS NOT LIMITED TO, FORMULATING CEMENT TO WITHSTAND ELEVATED SULFATE CONCENTRATIONS AND OTHER GEOCHEMICAL CONSTITUENTS OF COAL AND ASSOCIATED STRATA WHICH HAVE THE POTENTIAL TO ADVERSELY AFFECT THE INTEGRITY OF THE CEMENT.

[~~(6)~~] (5) Prevent gas flow in the annulus. IN AREAS OF KNOWN SHALLOW GAS PRODUCING ZONES, GAS BLOCK ADDITIVES AND LOW FLUID LOSS SLURRIES SHALL BE USED.

(b) **[The operator shall permit the cement to set to a minimum compressive strength of 350 pounds per square inch (psi) in accordance with the American Petroleum Institute's API Specification 10. The operator shall permit the cement to set for a minimum period of 8 hours prior to the resumption of actual drilling.] After the casing cement is placed behind surface casing [~~and intermediate casing when the intermediate casing is used in conjunction with the surface casing to isolate fresh groundwater~~], the operator shall permit the cement to set to a minimum designed compressive strength of 350 pounds per square inch (psi) at the casing seat. THE CEMENT PLACED AT THE BOTTOM 300 FEET OF THE SURFACE CASING SHALL CONSTITUTE A ZONE OF CRITCAL CEMENT AND SHALL ACHIEVE A 72 HOUR COMPRESSIVE STRENGTH OF 1,200 PSI AND THE FREE WATER SEPARATION SHALL BE NO MORE THAN SIX MILLILITERS PER 250 MILLILITERS OF CEMENT. IF THE SURFACE CASING IS LESS THAN 300 FEET, THE ENTIRE CEMENTED STRING SHALL CONSTITUTE A ZONE OF CRITICAL CEMENT.**

(c) After [~~the~~] ANY casing cement is placed and cementing operations are complete, the casing may not be disturbed for a minimum of eight (8) hours by:

> **(1) Releasing pressure on the cement head WITHIN FOUR HOURS OF CEMENTING if [~~float~~] CASING equipment check valves did not hold or [~~float~~] CASING equipment was not equipped with check valves. AFTER FOUR HOURS, THE PRESSURE MAY BE RELEASED AT A CONTINUOUS, GRADUAL RATE OVER THE NEXT FOUR HOURS PROVIDED THE FLOATS ARE SECURE;**
>
> **(2) Nippling up on or in conjunction to the casing;**
>
> **(3) Slacking off by the rig supporting the casing in the cement sheath; or**
>
> **(4) Running drill pipe[~~, wireline,~~] or other mechanical devices into or out of the wellbore WITH THE EXCEPTION OF A WIRELINE USED TO DETERMINE THE TOP OF CEMENT.**

[(c)] (d) Where special cement or additives are used, the operator may request approval from the Department to reduce the cement setting time specified in subsection **[(b)] (d)**.

(e) The operator shall notify the Department a minimum of one day before cementing of the surface casing begins, unless the cementing operation begins within 72 hours of commencement of drilling.

(f) A copy of the cement job log must be available at the well site for inspection by the Department during drilling operations. THE CEMENT JOB LOG MUST

INCLUDE THE MIX WATER TEMPERATURE AND PH, TYPE OF CEMENT WITH LISTING AND QUANTITY OF ADDITIVE TYPES, THE VOLUME, YIELD AND DENSITY IN POUNDS PER GALLON OF THE CEMENT AND THE AMOUNT OF CEMENT RETURNED TO THE SURFACE, IF ANY. CEMENTING PROCEDURAL INFORMATION MUST INCLUDE A DESCRIPTION OF THE PUMPING RATES IN BARRELS PER MINUTE, PRESSURES IN POUNDS PER SQUARE INCH, TIME IN MINUTES AND SEQUENCE OF EVENTS DURING THE CEMENTING OPERATION.

(G) The cement job log shall be maintained by the operator after drilling operations for at least five years and be made available to the Department upon request.

* * * * *

OPERATING WELLS

§ 78.88. Mechanical integrity of operating wells.

(a) Except for wells regulated under Subchapter H (relating to Underground gas storage) AND WELLS THAT HAVE BEEN GRANTED INACTIVE STATUS, the operator shall inspect each operating well at least quarterly to ensure it is in compliance with the well construction and operating requirements of this chapter and the Act. The results of the inspections shall be recorded and retained by the operator for at least five years and shall be available for review by the Department and the coal owner or operator.

(b) At a minimum, inspections must determine:

(1) The well-head pressure or water level measurement;

(2) The open flow on the annulus of the production casing or the annulus pressure if the annulus is shut in;

(3) If there is evidence of gas escaping from the well and the amount escaping, using measurement or best estimate of quantity;

(4) If there is evidence of progressive corrosion, rusting or other signs of equipment deterioration.

(c) For structurally sound wells in compliance with §78.73(c), the operator shall follow the reporting schedule outlined in subsection (e).

(d) For wells exhibiting progressive corrosion, rusting or other signs of equipment deterioration that compromise the integrity of the well, or the well is not in compliance with §78.73(c), the operator shall immediately notify the Department and take corrective actions to repair or replace defective equipment or casing or

mitigate the excess pressure on the surface casing seat[,] OR coal protective casing seat [~~or intermediate casing seat when the intermediate casing is used in conjunction with the surface casing to isolate fresh groundwater~~] according to the following hierarchy:

(1) The operator shall reduce the shut-in or producing back pressure on the casing seat to achieve compliance with § 78.73(c).

(2) The operator shall retrofit the well by installing production casing to reduce the pressure on the casing seat to achieve compliance with § 78.73(c). The annular space surrounding the production casing must be open to the atmosphere. The production casing shall be either cemented to the surface or installed on a permanent packer. The operator shall notify the Department at least seven days prior to initiating the corrective measure.

(3) Additional mechanical integrity tests, including but not limited to pressure tests, may be required by the Department to demonstrate the integrity of the well.

(e) The operator shall submit an annual report to the Department identifying the compliance status of each well with the mechanical integrity requirements of this section. The report shall be submitted on forms prescribed by, and available from, the Department or in a similar manner approved by the Department.

§ 78.89. Gas migration response.

(a) When an operator or owner is notified of or otherwise made aware of a POTENTIAL natural gas migration incident, the operator shall immediately [~~notify the Department and, if so directed by the Department,~~] conduct an investigation of the incident. The purpose of the investigation is to determine the nature of the incident, assess the potential for hazards to public health and safety, and mitigate any hazard posed by [~~the levels of natural gas~~] THE CONCENTRATIONS OF STRAY NATURAL GAS. [~~The operator, in conjunction with the Department and local emergency response agencies, shall take measures necessary to ensure public health and safety.~~]

(b) The investigation undertaken by the operator pursuant to subsection (a) shall include, but not be limited to:

(1) [~~An~~] A SITE VISIT AND interview with the complainant to obtain information about the complaint and to assess the reported [~~problem~~] NATURAL GAS MIGRATION INCIDENT;

(2) A field survey to assess the presence and concentrations of natural gas and aerial extent of the stray natural gas; and

(3) If necessary, [~~Establishment of~~] establish monitoring locations at potential sources, in potentially impacted structures, and the subsurface [~~if necessary~~].

~~(c) If the level of natural gas is greater than 10 percent of the lower explosive limit of natural gas, the operator shall:~~

~~(1) Immediately notify the local emergency response agency, police and fire departments and the Department;~~

~~(2) Conduct an immediate field survey of the operator's adjacent oil or gas wells to assess the wells for mechanical integrity, defective casing or cementing, and excess pressures within any part of the well. The initial area of assessment shall include wells within 2,500 feet and expanded to a greater distance if necessary as determined by the Department;~~

~~(3) Initiate mitigation controls, which may include remedial measures, access control, advisories, evacuation, signs and other actions;~~

~~(d) The operator shall take action to correct any defect in the oil and gas wells to mitigate the stray gas incident.~~

~~(e) The operator and owner shall report to the Department by phone within 12 hours after the interview with the complainant and field survey of the natural gas levels. A follow-up report shall be filed in writing with the Department within three days of the complaint. This follow-up report must include the results of the investigation, monitoring results and measures taken by the operator to repair any defects at any of the adjacent oil and gas wells.~~]

(C) IF COMBUSTIBLE GAS IS DETECTED INSIDE A BUILDING OR STRUCTURE AT CONCENTRATIONS EQUAL TO OR GREATER THAN 10% OF THE LOWER EXPLOSIVE LIMIT (L.E.L.), THE OPERATOR SHALL:

(1) IMMEDIATELY NOTIFY THE DEPARTMENT, LOCAL EMERGENCY RESPONSE AGENCY, GAS AND ELECTRIC UTILITY COMPANIES, POLICE AND FIRE DEPARTMENTS AND, IN CONJUNCTION WITH THE DEPARTMENT AND LOCAL EMERGENCY RESPONSE AGENCIES, TAKE MEASURES NECESSARY TO ENSURE PUBLIC HEALTH AND SAFETY;

(2) INITIATE MITIGATION MEASURES NECESSARY TO CONTROL AND PREVENT FURTHER MIGRATION;

(3) IMPLEMENT THE ADDITIONAL INVESTIGATION AND MITIGATION MEASURES AS PROVIDED IN SUBSECTION (E)(1) – (5) .

(D) THE OPERATOR SHALL NOTIFY THE DEPARTMENT AND, IN CONJUNCTION WITH THE DEPARTMENT, TAKE MEASURES NECESSARY TO ENSURE PUBLIC HEALTH AND SAFETY, IF SUSTAINED DETECTABLE CONCENTRATIONS OF COMBUSTIBLE GAS SATISFY ANY OF THE FOLLOWING:

(1) GREATER THAN 1% AND LESS THAN 10% OF THE L.E.L., IN A BUILDING OR STRUCTURE;

(2) EQUAL TO OR GREATER THAN 25% OF THE L.E.L. IN A WATER WELL HEAD SPACE;

(3) DETECTABLE IN THE SOILS; OR

(4) EQUAL TO OR GREATER THAN 7 MG/L DISSOLVED METHANE IN WATER.

(E) THE DEPARTMENT MAY REQUIRE THE OPERATOR TO TAKE THE FOLLOWING ADDITIONAL ACTIONS:

(1) CONDUCT A FIELD SURVEY TO ASSESS THE PRESENCE AND CONCENTRATIONS OF COMBUSTIBLE GAS AND THE AREAL EXTENT OF THE COMBUSTIBLE GAS IN THE SOILS, SURFACE WATER BODIES, WATER WELLS, AND OTHER POTENTIAL MIGRATION PATHWAYS;

(2) COLLECT GAS AND/OR WATER SAMPLES AT A MINIMUM FOR MOLECULAR AND STABLE CARBON AND HYDROGEN ISOTOPE ANALYSES FROM THE IMPACTED LOCATIONS SUCH AS WATER WELLS, AND FROM POTENTIAL SOURCES OF THE MIGRATION SUCH AS GAS WELLS;

(3) CONDUCT AN IMMEDIATE EVALUATION OF THE OPERATOR'S ADJACENT OIL OR GAS WELLS TO DETERMINE WELL CEMENT AND CASING INTEGRITY AND TO EVALUATE THE POTENTIAL MECHANISM OF MIGRATION. THIS EVALUATION MAY INCLUDE ASSESSING PRESSURES FOR ALL CASING INTERVALS, REVIEWING RECORDS FOR INDICATIONS OF DEFECTIVE CASING OR CEMENT, APPLICATION OF CEMENT BOND LOGS, ULTRASONIC IMAGING TOOLS, GEOPHYSICAL LOGS, AND OTHER MECHANICAL INTEGRITY TESTS AS REQUIRED. THE INITIAL AREA OF ASSESSMENT SHALL INCLUDE WELLS WITHIN A RADIUS OF 2,500 FEET AND MAY BE EXPANDED IF REQUIRED BY THE DEPARTMENT;

(4) TAKE ACTION TO CORRECT ANY DEFECT IN THE OIL AND GAS WELLS TO MITIGATE THE STRAY GAS INCIDENT.

(5) ESTABLISH MONITORING LOCATIONS AND MONITORING FREQUENCY IN CONSULTATION WITH THE DEPARTMENT AT POTENTIAL SOURCES, IN POTENTIALLY IMPACTED STRUCTURES, AND THE SUBSURFACE.

(F) IF CONCENTRATIONS OF STRAY NATURAL GAS AS DEFINED IN SUBSECTIONS (C) OR (D) ARE NOT DETECTED, THE OPERATOR SHALL NOTIFY THE DEPARTMENT, AND DO THE FOLLOWING IF REQUESTED BY THE DEPARTMENT:

(1) CONDUCT ADDITIONAL MONITORING,
(2) DOCUMENT FINDINGS
(3) SUBMIT A CLOSURE REPORT.

(G) *REPORTING REQUIREMENTS* - IF CONCENTRATIONS OF STRAY NATURAL GAS ARE DETECTED INSIDE A BUILDING OR STRUCTURE AT CONCENTRATIONS EQUAL TO OR GREATER THAN 10% OF THE L.E.L., THE OPERATOR AND OWNER SHALL FILE A REPORT WITH THE DEPARTMENT BY PHONE AND EMAIL WITHIN 24 HOURS AFTER THE INTERVIEW WITH THE COMPLAINANT AND FIELD SURVEY OF THE EXTENT OF STRAY NATURAL GAS. ADDITIONAL DAILY OR WEEKLY REPORTS SHALL BE SUBMITTED IF REQUESTED BY THE DEPARTMENT.

(D) FOR ALL STRAY NATURAL GAS MIGRATION INCIDENTS, A FINAL WRITTEN REPORT DOCUMENTING THE RESULTS OF THE INVESTIGATION SHALL BE SUBMITTED TO THE DEPARTMENT FOR APPROVAL WITHIN 30 DAYS OF THE CLOSE OF THE INCIDENT, OR IN A TIMEFRAME OTHERWISE APPROVED BY THE DEPARTMENT. THE FINAL REPORT SHALL INCLUDE THE FOLLOWING

(1) DOCUMENTATION OF ALL RESULTS OF THE INVESTIGATION, INCLUDING ANALYTICAL DATA, MONITORING RESULTS
(2) OPERATIONAL CHANGES ESTABLSIHED AT THE OPERATOR'S OIL AND GAS WELLS IN PENNSYLVANIA
(3) MEASURES TAKEN BY THE OPERATOR TO REPAIR ANY DEFECTS AT ANY OF THE INVESTIGATED OIL AND GAS WELLS.

(E) ALL REPORTS SUBMITTED IN ACCORDANCE WITH THIS SECTION THAT CONTAIN AN ANALYSIS OF GEOLOGICAL OR ENGINEERING DATA SHALL BE PREPARED AND SEALED BY A PENNSYLVANIA LICENSED GEOLOGIST OR ENGINEER.

PLUGGING

§ 78.92. Wells in coal areas—surface or coal protective casing is cemented.

(a) In a well underlain by a workable coal seam, where the surface casing or coal protective casing is cemented and the production casing is not cemented or the production casing is not present, the owner or operator shall plug the well as follows:

(1) The retrievable production casing shall be removed **by applying a pulling force at least equal to the casing weight plus 5000 pounds or 120% whichever is greater. If this fails, an attempt shall be made to separate the casing by cutting, ripping, shooting or other method approved by the Department, and making a second attempt to remove the casing by exerting a pulling force equal to the casing weight plus 5,000 pounds or 120 percent of the casing weight, whichever is greater. [and the] The** well shall be filled with nonporous material from the total depth or attainable bottom of the well, to a point **50 feet** below **[20 feet above the top of]** the lowest stratum bearing or having borne oil, gas or water. At this point there shall be placed a plug of cement, which shall extend for at least 50 feet above **this stratum [that point]. Each overlying formation bearing or having borne oil, gas or water shall be plugged with cement a minimum of 50 feet below this formation to a point 50 feet above this formation. The zone between cement plugs shall be filled with nonporous material. [Between this sealing plug and a point 20 feet above the next higher stratum bearing or having borne oil, gas or water, the hole shall be filled with nonporous material and at that point there shall be placed another 50-foot plug of cement which] The cement plugs shall be placed in a manner that** will completely seal the hole. **[In like manner, the hole shall be filled and plugged, with reference to each of the strata bearing or having borne oil, gas or water.]** The operator may treat multiple strata as one stratum and plug as described in this subsection with a single column of cement or other materials approved by the Department. Where the production casing is not retrievable, the operator shall plug that portion of the well under § 78.91(d) (relating to general provisions).

* * * * *

(b) The owner or operator shall plug a well, where the surface casing, coal protective casing and production casing are cemented, as follows:

* * * * *

(3) Following the plugging of the cemented portion of the production casing, the uncemented portion of the production casing shall be separated from the cemented portion and retrieved **by applying a pulling force at least equal to the casing weight plus 5000 pounds or 120% whichever is greater. If this fails, an attempt shall be made to separate the casing by cutting, ripping, shooting or other method approved by the Department, and making a second attempt to remove the casing by exerting a pulling force equal to the casing weight plus 5,000 pounds or 120 percent of the casing weight, whichever is greater** . The maximum distance the stub of the uncemented portion of the production casing may extend is 100 feet below the surface or coal protective casing whichever is lower. In no case may the uncemented portion of the

casing left in the well extend through a formation bearing or having borne oil, gas or water. Other stratum above the cemented portion of the production casing bearing or having borne oil, gas or water shall be plugged by filling the hole with nonporous material to 20 feet above the stratum and setting a 50-foot plug of cement. The operator may treat multiple strata as one stratum and plug as described in this subsection with a single column of cement or other material as approved by the Department. When the uncemented portion of the production casing is not retrievable, the operator shall plug that portion of the well under § 78.91(d).

§ 78.93. Wells in coal areas—surface or coal protective casing anchored with a packer or cement.

(a) In a well where the surface casing or coal protective casing and production casing are anchored with a packer or cement, the owner or operator shall plug the well as follows:

(1) The retrievable production casing shall be removed **by applying a pulling force at least equal to the casing weight plus 5000 pounds or 120% whichever is greater. If this fails, an attempt shall be made to separate the casing by cutting, ripping, shooting or other method approved by the Department, and making a second attempt to remove the casing by exerting a pulling force equal to the casing weight plus 5,000 pounds or 120 percent of the casing weight, whichever is greater.**

[and the] **The** well shall be filled with nonporous material from the total depth or attainable bottom of the well, to a point **50 feet below** **[20 feet above the top of]** the lowest stratum bearing or having borne oil, gas or water. At this point there shall be placed a plug of cement, which shall extend for at least 50 feet above **this stratum** **[that point].** **Each overlying formation bearing or having borne oil, gas or water shall be plugged with cement a minimum of 50 feet below this formation to a point 50 feet above this formation. The zone between cement plugs shall be filled with nonporous material.** **[Between this sealing plug and a point 20 feet above the next higher stratum bearing or having borne oil, gas or water, the hole shall be filled with nonporous material and at that point there shall be placed another 50-foot plug of cement which]** **The cement plugs shall be placed in a manner that** will completely seal the hole. **[In this manner, the hole shall be filled and plugged, with reference to each of the strata bearing or having borne oil, gas or water.]** The operator may treat multiple strata as one stratum and plug as described in this subsection with a single column of cement or other material as approved by the Department. When the production casing is not retrievable, the operator shall plug this portion of the well under § 78.91(d) (relating to general provisions).

(2) The well shall then be filled with nonporous material to a point approximately 200 feet below the lowest workable coal seam, or surface or coal protective casing seat, whichever is deeper. Beginning at this point a 100-foot plug of cement shall be installed.

(3) After it has been established that the surface casing or coal protective casing is free and can be retrieved, the surface or coal protective casing shall be retrieved **by applying a pulling force at least equal to the casing weight plus 5000 pounds or 120%**

whichever is greater. If this fails, an attempt shall be made to separate the casing by cutting, ripping, shooting or other method approved by the Department, and making a second attempt to remove the casing by exerting a pulling force equal to the casing weight plus 5,000 pounds or 120 percent of the casing weight, whichever is greater. [and a] A string of casing with an outside diameter of not less than 4 1/2 inches for gas wells, or not less than 2 inches for oil wells, shall be run to the top of the 100-foot plug described in paragraph (2) and cemented to the surface.

*   *   *   *   *

§ 78.94. Wells in noncoal areas—surface casing is not cemented or not present.

(a) The owner or operator shall plug a noncoal well, where the surface casing and production casing are not cemented, or is not present as follows:

(1) The retrievable production casing shall be removed **by applying a pulling force at least equal to the casing weight plus 5000 pounds or 120% whichever is greater. If this fails, an attempt shall be made to separate the casing by cutting, ripping, shooting or other method approved by the Department, and making a second attempt to remove the casing by exerting a pulling force equal to the casing weight plus 5,000 pounds or 120 percent of the casing weight, whichever is greater.** The well shall be filled with nonporous material from the total depth or attainable bottom of the well, to a point **50 feet below [20 feet above the top of]** the lowest stratum bearing or having borne oil, gas or water. At this point there shall be placed a plug of cement, which shall extend for at least 50 feet above **this stratum [that point]. Each overlying formation bearing or having borne oil, gas or water shall be plugged with cement a minimum of 50 feet below this formation to a point 50 feet above this formation. The zone between cement plugs shall be filled with nonporous material. [Between this sealing plug and a point 20 feet above the next higher stratum bearing or having borne oil, gas or water, the hole shall be filled with nonporous material and at that point there shall be placed another 50-foot plug of cement which] The cement plugs shall be placed in a manner that** will completely seal the hole. **[The hole shall be filled and plugged, with reference to each of the strata bearing or having borne oil, gas or water.]** The operator may treat multiple strata as one stratum and plug as described in this paragraph with a single column of cement or other materials as approved by the Department. When the production casing is not retrievable, the operator shall plug this portion of the well under § 78.91(d) (relating to general provisions).

(2) After plugging strata bearing or having borne oil, gas or water, the well shall be filled with nonporous material to approximately 100 feet below the surface casing seat and there shall be placed another plug of cement or other equally nonporous material approved by the Department extending at least 50 feet above that point.

(3) After setting the uppermost 50-foot plug, the retrievable surface casing shall be removed **by applying a pulling force at least equal to the casing weight plus 5000 pounds or 120% whichever is greater. If this fails, an attempt shall be made to**

separate the casing by cutting, ripping, shooting or other method approved by the Department, and making a second attempt to remove the casing by exerting a pulling force equal to the casing weight plus 5,000 pounds or 120 percent of the casing weight, whichever is greater. **[and the]** **The** hole shall be filled from the top of the 50-foot plug to the surface with nonporous material other than gel. If the surface casing is not retrievable, the hole shall be filled from the top of the 50-foot plug to the surface with a noncementing material.

*   *   *   *   *

§ 78.95. Wells in noncoal areas—surface casing is cemented.

(a) The owner or operator shall plug a well, where the surface casing is cemented and the production casing is not cemented or not present, as follows:

(1) The retrievable production casing shall be removed **by applying a pulling force at least equal to the casing weight plus 5000 pounds or 120% whichever is greater. If this fails, an attempt shall be made to separate the casing by cutting, ripping, shooting or other method approved by the Department, and making a second attempt to remove the casing by exerting a pulling force equal to the casing weight plus 5,000 pounds or 120 percent of the casing weight, whichever is greater.** **[and]** **T[t]**he well shall be filled with nonporous material from the total depth or attainable bottom of the well, to a point **50 feet below** **[20 feet above the top of]** the lowest stratum bearing or having borne oil, gas or water. At this point there shall be placed a plug of cement, which shall extend for at least 50 feet above **this stratum** **[that point].** **Each overlying formation bearing or having borne oil, gas or water shall be plugged with cement a minimum of 50 feet below this formation to a point 50 feet above this formation. The zone between cement plugs shall be filled with nonporous material. [Between this sealing plug and a point 20 feet above the next higher stratum bearing or having borne oil, gas or water, the hole shall be filled with nonporous material and at that point there shall be placed another 50-foot plug of cement]** **The cement plugs shall be placed in a manner that will completely seal the hole**. **[The hole shall be filled and plugged, with reference to each of the strata bearing or having borne oil, gas or water.]** The operator may treat multiple strata as one stratum and plug as described in this subsection with a single column of cement or other materials as approved by the Department. When the production casing is not retrievable, the operator shall plug this portion of the well under § 78.91(d) (relating to general provisions).

*   *   *   *   *

§ 78.96. Marking the location of a plugged well**.**

(a) Upon the completion of plugging or replugging a well, the operator shall erect over the plugged well a permanent marker of concrete, metal**, plastic or equally durable material** **[or metal and concrete].** The marker shall extend at least 4 feet above the ground surface and enough below the surface to make the marker permanent. **Cement**

may be used to hold the marker in place provided the cement does not prevent inspection of the adequacy of the well plugging. The permit or registration number shall be stamped or cast or otherwise permanently affixed to the marker. In lieu of placing the marker above the ground surface, the marker may be buried below plow depth and shall contain enough metal to be detected at the surface by conventional metal detectors

* * * **

SUBCHAPTER E. WELL REPORTING

§ 78.121. **[Annual] P[p]**roduction report**ing.**

(a) The well operator shall submit an annual production and status report for each **PERMITTED OR REGISTERED** well on an individual basis, on or before **[March 31] February 15** of each year. **The operator of a well [~~which produces gas~~] PERMITTED TO PRODUCE GAS from the Marcellus shale formation shall submit a production and status report for each well on an individual basis, on or before February 15 and August 15 of each year.** Production shall be reported for the preceding calendar year **or in the case of a Marcellus shale well, for the preceding six months**. When the production data is not available to the operator on a well basis, the operator shall report production on the most well-specific basis available. The annual production report [~~**shall**~~] **MUST** include information on the amount and type of waste produced and the method of waste disposal or reuse. Waste information submitted to the Department in accordance with this subsection [~~**shall]**~~ **IS DEEMED TO** satisfy the residual waste biennial reporting requirements of § 287.52 (relating to biennial report).

(b) The **[~~annual~~]** production report shall be submitted **ELECTRONICALLY TO THE DEPARMENT THROUGH ITS WEBSITE.[on forms prescribed by, and available from, the Department or in a similar manner approved by the Department.]**

§ 78.122. Well record and completion report.

(a) For each well that is drilled or altered, the operator shall keep a detailed drillers log at the well site available for inspection until drilling is completed. Within 30 calendar days of cessation of drilling or altering a well, the well operator shall submit a well record to the Department on a form provided by the Department that includes the following information:

* * * * *

(6) Size and depth of conductor pipe, surface casing, coal protective casing, **INTERMEDIATE CASING,** production casing and borehole.

* * * * *

[~~(9)~~] (10) A certification by the operator that the well has been constructed in accordance with this chapter and any permit conditions imposed by the Department.

[(10)] 11 Other information required by the Department.

(b) Within 30 calendar days after completion of the well, the well operator shall submit a completion report to the Department on a form provided by the Department that includes the following information:

(1) Name, address and telephone number of the permittee.

(2) Name, address and telephone number of the service companies.

(3) Permit number and farm name and number.

(4) Township and county.

(5) Perforation record.

(6) Stimulation record **WHICH INCLUDES THE FOLLOWING:** [~~**including pump rates, pressure, total volume and list of hydraulic fracturing chemicals used, the volume of water used, and identification of water sources used pursuant to an approved water management plan.**~~**]**

(I) A DESCRIPTIVE LIST OF THE CHEMICAL ADDITIVES IN THE STIMULATION FLUID, INCLUDING ANY ACID, BIOCIDE, BREAKER, BRINE, CORROSION INHIBITOR, CROSSLINKER, DEMULSIFIER, FRICTION REDUCER, GEL, IRON CONTROL, OXYGEN SCAVENGER, PH ADJUSTING AGENT, PROPPANT, SCALE INHIBITOR, AND SURFACTANT;

(II) THE PERCENT BY VOLUME OF EACH CHEMICAL ADDITIVE IN THE STIMULATION FLUID;

(III) A LIST OF THE CHEMICALS IN THE MATERIAL SAFETY DATA SHEETS, BY NAME AND CHEMICAL ABSTRACT SERVICE NUMBER, CORRESPONDING TO THE APPROPRIATE CHEMICAL ADDITIVE;

(IV) THE PERCENT BY VOLUME OF EACH CHEMICAL LISTED IN THE MATERIAL SAFETY DATA SHEETS;

(V) THE TOTAL VOLUME OF THE BASE FLUID;

(VI) A LIST OF WATER SOURCES USED PURSUANT TO AN APPROVED WATER MANAGEMENT PLAN AND THE VOLUME OF WATER USED FROM EACH SOURCE;

(VII) THE TOTAL VOLUME OF RECYCLED WATER USED; AND

(VIII) THE PUMP RATE AND PRESSURE USED IN THE WELL.

(7) Actual open flow production and **[rock]** [**~~reservoir~~]** **SHUT IN SURFACE** pressure.

(8) Open flow production and **[rock]** [**~~reservoir~~]** **SHUT IN SURFACE** pressure, measured 24 hours after **[treatment]** **completion**.

(c) [~~No information described in subsection (b)(5) – (8) will be required as part of the report unless the operator has had the information compiled in the ordinary course of business. No interpretation of the data is to be filed.~~] **WHEN THE WELL OPERATOR SUBMITS A STIMULATION RECORD, IT MAY DESIGNATE SPECIFIC PORTIONS OF THE STIMULATION RECORD AS CONTAINING A TRADE SECRET OR CONFIDENTIAL PROPRIETARY INFORMATION. THE DEPARTMENT SHALL PREVENT DISCLOSURE OF SUCH DESIGNATED CONFIDENTIAL INFORMATION TO THE EXTENT PERMITTED BY THE RIGHT TO KNOW LAW, 65 P.S. 67.101 ET SEQ.**

(D) IN ADDITION TO SUBMITTING A STIMULATION RECORD TO THE DEPARTMENT PURSUANT TO SUBSECTION (B), AND SUBJECT TO THE PROTECTIONS AFFORDED FOR TRADE SECRETS AND CONFIDENTIAL PROPRIETARY INFORMATION UNDER THE RIGHT TO KNOW LAW, 65 P.S. 67.101 ET SEQ., THE OPERATOR SHALL ARRANGE TO PROVIDE A LIST OF THE CHEMICAL CONSTITUENTS OF THE CHEMICAL ADDITIVES USED TO HYDRAULICALLY FRACTURE A WELL, BY CHEMICAL NAME AND ABSTRACT SERVICE NUMBER, UNLESS THE ADDITIVE DOES NOT

HAVE SUCH A NUMBER, TO THE DEPARTMENT UPON WRITTEN REQUEST BY THE DEPARTMENT.

* * * * *

Notice of Final Rulemaking
Department of Environmental Protection
Environmental Quality Board
25 *Pa. Code,* Chapter 78
Oil and Gas Well Cementing and Casing

Order

The Environmental Quality Board (Board) by this order amends 25 *Pa. Code*, Chapter 78 (relating to oil and gas well requirements) as set forth in Annex A.

Properly constructed and operated oil and gas wells are critical to protecting water supplies and public safety. If a well is not properly cased and cemented, natural gas in subsurface formations may potentially migrate from the wellbore through bedrock and soil. This stray gas may adversely affect water supplies, as well as accumulate in or adjacent to structures such as residences and water wells. Under certain conditions, stray gas has the potential to cause a fire or explosion. These situations present a serious threat to public health and safety as well as the environment. The purpose of this final rulemaking is to improve drilling, casing, cement, testing, monitoring and plugging requirements for oil and gas wells to minimize gas migration and protect water supplies.

The final form rulemaking differs from the proposed rulemaking in several important respects. The differences reflect the concerns raised by the regulated community and the public, resulting in an improved rule. The changes to the final form rulemaking strengthen well design requirements to prevent gas migration incidents.

The significant revisions to the final form rulemaking include: the addition of a provision that requires operators to have a pressure barriers plan to minimize well control events; the addition of a provision that requires operators to keep a list of emergency contact phone numbers at the well site; amended provisions that clarify how and when blow-out prevention equipment is to be installed and operated; the addition of a provision that requires operators to condition the wellbore to ensure an adequate bond between the cement, casing and the formation; the addition of provisions that require the use of centralizers to ensure that casings are properly positioned in the wellbore; the addition of a provision that improves the quality of the cement placed in the casing that protects fresh groundwater; the addition of provisions that specify the actions an operator must take in the event of a gas migration incident; and revisions to the reporting requirements for chemicals used to hydraulically fracture a well.

This order was adopted by the Board at its meeting of _________(blank)______.

A. Effective Date

These amendments will go into effect upon publication in the *Pennsylvania Bulletin* as final rulemaking.

B. Contact Persons

For further information contact Scott R. Perry, Director, Bureau of Oil and Gas Management, Rachel Carson State Office Building, 5th Floor, P.O. Box 8765, Harrisburg, PA 17105-8461, (717) 772-2199; or Elizabeth A. Nolan, Assistant Counsel, Bureau of Regulatory Counsel, Rachel Carson State Office Building, 9th Floor, P.O. Box 8464, Harrisburg, PA 17105-8464, (717) 787-7060. Persons with a disability may use the AT&T Relay Service by calling (800) 654-5984 (TDD users) or (800) 654-5988 (voice users). This final form rulemaking is available on the Department of Environmental Protection's website at http://www.dep.state.pa.us

C. Statutory Authority

The final form rulemaking is being made under the authority of Section 604 of the Oil and Gas Act (58 P.S. § 601.604), which directs the Board to adopt regulations necessary to implement the Act, and Section 1917-A and 1920-A of the Administrative Code (71 P.S. §§ 510-17 and 510-20). Section 1917-A authorizes and requires the Department to protect the people of this Commonwealth from unsanitary conditions and other nuisances, including any condition that is declared to be a nuisance by any law administered by the Department. Section 1920-A authorizes the Board to promulgate regulations of the Department.

D. Background of the Amendments

Many of the regulations governing well construction and water supply replacement were promulgated in July 1989 and remained largely unchanged until this rulemaking. Since that time, recent advances in drilling technology have attracted interest in producing natural gas from the Marcellus Shale, a rock formation that underlies approximately two-thirds of Pennsylvania. New well drilling and completion practices now employed to extract natural gas from the Marcellus Shale and other similar shale formations in Pennsylvania, as well as several recent incidents of contaminated drinking water caused by traditional and Marcellus Shale wells resulted in the Department's decision to re-evaluate the existing well construction requirements.

It was determined that the existing regulations were not specific enough in detailing the Department's expectations of a properly cased and cemented well, especially in light of the new techniques used by Marcellus Shale operators. The Department also determined that the existing regulations did not address the need for an immediate response by operators to a gas migration complaint and did not require routine inspection of existing wells by the operator.

The final rulemaking contains revised design, construction, operational, monitoring, plugging, water supply replacement, and hydraulic fracturing reporting requirements. The final rulemaking also provides material specifications and performance testing to ensure the proper casing, cementing and operation of a well. Additionally, the final rulemaking contains new provisions that require routine inspection of wells and outline the actions an operator and the Department must take in the event of a gas migration incident.

The proposed rulemaking was published in the *Pennsylvania Bulletin* on July 10, 2010. See 40 *Pa.B.* 3845 (July 10, 2010). The public comment period closed on August 9, 2010. In addition, five public hearings were held: July 19, 2010, in Tunkhannock, PA; July 21, 2010, in Williamsport, PA; July 22, 2010, in Meadville, PA; July 22, 2010, in Pittsburgh, PA; and July 26, 2010, in Pittsburgh, PA.

Prior to recommending that the proposed regulations be offered to the Environmental Quality board, the Oil and Gas Technical Advisory board (TAB) formed a technical subcommittee with representatives from various companies, trade groups and consultants to review and provide comments on the proposed rulemaking. The Department met with TAB and this subcommittee on October 28, 2009, January 14, 2010, January 21, 2010 and March 25, 2010.

The Department presented the draft final form rulemaking to TAB on September 16, 2010. During this discussion, TAB members made several recommendations regarding the definition of unconventional formations, use of blow-out preventers, cementing the intermediate casing, producing gas off the intermediate casing, and the actions the operator must take when it loses circulation of cement. At the conclusion of the meeting, TAB members were not able to endorse nor disapprove the rulemaking and instead expressed an interest in having the TAB subcommittee review the amendments to the final form rulemaking.

E. Summary of Comments and Responses

The Board received approximately 2,000 comments regarding the proposed Oil and Gas Well Casing and Cementing regulations during the public hearings and public comment period. Many of the comments received sought clarification or additional protective measures. The majority of comments were supportive of the proposal.

Several commentators made suggestions seeking to clarify the definition of “deepest fresh groundwater, including suggesting that the term be defined with reference to certain levels of total dissolved solids (TDS) ranging from 500 to 10,000 mg/l TDS. The Board appreciated these comments, but decided that numerical criteria should not be used to define deepest fresh groundwater because many water supplies provide water that exceed the 500 mg/l drinking water standard, but 10,000 mg/l is far too saline for Pennsylvania drinking water supplies. It is critical that the casing be set deep enough to isolate usable water supplies but not so deep that brine be permitted to co-mingle with fresh groundwater. It is also important to recognize that testing water produced during drilling will not yield accurate test results. For these reasons, the final form rulemaking has been amended to require operators to identify how the deepest fresh groundwater was determined and record the information in the casing and cementing plan.

Many commentators sought clarification regarding the provisions that require an operator who affects a water supply to restore or replace the affected water supply with an alternate supply adequate in quantity and quality for the purposes served by the supply. The amendments to § 78.51 reflect the Department’s interpretation of an adequate alternate water supply according to recent caselaw.

Several commentators suggest that all replaced or restored water should meet safe drinking water standards. The Board deems a supply adequate if it meets safe drinking water standards or is comparable to the unaffected water supply if that water supply didn’t meet those standards.

A commentator was uncertain about who would determine reasonable foreseeable uses. The regulation states that it is the duty of the Department to determine if the operator is in compliance with this subsection.

Additionally, several commentators were concerned that § 78.51(h) did not provide a timely response for affected water supplies. The Board agrees and amends § 78.51(h) to require operators to notify the Department within 24 hours of receiving a report that a water supply has been affected by pollution of diminution caused by drilling activities.

Several commentators objected to the provisions that would allow the use of used pipe. The Board considers used casing to be acceptable in certain applications, notably in low pressured shallow oil wells that do not produce gas. In these instances, used casing has been utilized successfully and has been shown to be suitable for long-term use in these applications. All used casing, however, is subject to the casing integrity requirement of § 78.84(b), as well as new requirements for pressure testing in § 78.84(c).

Many commentators suggested amendments to § 78.85(b) that would require a 72-hour compressive strength standard of at least 1,200 psi across critical zones of cement at the bottom of the casing seat where the highest pressures and stresses are likely to be encountered and in places where the well bore passes through aquifers and drinking water. The Board agrees and has amended §78.85(b) to require a zone of critical cement at the surface casing seat which must achieve a 72-hour compressive strength of 1200 psi and have a free-water separation of no more than six milliliters per 250 milliliters of cement.

Several commentators suggest that the cement ticket include testing of pH, temperature, and a record of the wait on cement time. The Board agrees and the regulation has been revised accordingly.

Some commentators objected to the quarterly mechanical integrity inspections required by §78.88(a), arguing that the requirement is excessive. While several commentators believed that quarterly inspections were not enough, other commentators supported § 78.88(a) quarterly inspection requirements. The Board has decided that quarterly inspections are sufficient to ensure that well pressures are within allowable limits and the casing is structurally sound. The Board does not consider quarterly mechanical integrity testing to be excessive. Rather, the inspections provide the operator an opportunity to correct problems at the well before such problems create a condition that will require significant time and expense to address. The Board has also determined that required evaluation of the well does not include invasive procedures.

Several commentators made suggestions to § 78.89 regarding the gas migration response requirements, including a provision requiring immediate notification to the Department. The Board agrees and has amended the final form rulemaking to require the operator to immediately conduct an investigation and contact the Department.

Commentators suggested that operators conduct an initial response action to determine the nature of the incident, assess the potential for hazards to public health and safety, and mitigate any hazard posed by the concentration of stray natural gas in the environment. Commentators suggested what the investigation include a site visit and an interview of the complainant. Commentators suggested that the actions that an operator must take in the event of a reported gas migration incident be delineated by the concentration of combustible gas detected in the investigation. Commentators also suggested other additional investigation and mitigation measures that operators should be required to take, including a field survey, the collection of gas and/or water samples, the establishment of monitoring locations, and an evaluation of the operator's adjacent wells. Commentators also suggested certain reporting requirements following a reported gas migration incident. The Board agrees with many of the commentators suggestions and has revised § 78.89. These changes largely follow the commentators' suggestions. The revisions also require continued monitoring of gas migration complaints where the levels of dissolved methane in the water supply exceed 7 milligrams per liter. This level is based on 25% of the capacity of water to contain dissolved methane under one atmosphere of pressure. This number is much more certain and scientifically based than the unknown "background" level proposed by the commentator.

Commentators suggested that the information required in the completion report's stimulation record be expanded to require more specific information, including information regarding the chemical additives used and a the chemicals listed in the operator's Material Safety Data Sheets by Chemical Abstract Number. Other commentators object to requirements that require operators to submit confidential information and suggest that the issue of confidentiality be addressed in § 78.122. The Board has expanded the stimulation record requirements in subsection §78.122(b)(6) to include the Chemical Abstract Number for each Material Safety Data Sheet-listed hydraulic fracturing chemical used, as well as the percent (by volume) of each listed chemical used. The Board has also amended this subsection allowing the designation of confidential or trade secret information. The Department shall prevent disclosure of such designated confidential information to the extent permitted by the Right To Know Law, 65 P.S. 67.101 et seq.

F. Summary of Final Form Regulation and Changes from Proposed to Final Form Rulemaking

§ 78.1. Definitions.

Section 78.1 amends the definitions of the following terms to improve clarity or to explain new or existing provisions: "casing seat," "cement" and "surface casing." Section 78.1 also adds definitions for the following terms to explain new or existing provisions within Chapter 78: "cement job log," "conductor pipe" and "intermediate casing."

The final form rulemaking amends the following definitions listed above in response to public comment to improve clarity: "casing seat," "cement job log," "intermediate casing" and "surface casing."

Section 78.1 removes the definition of "retrievable" and inserts the substantive portion of the definition into the appropriate plugging regulations.

The final form rulemaking § 78.1 adds definitions for “L.E.L” and “unconventional formation.”

§ 78.51. Protection of water supplies.

The Oil and Gas Act requires an operator who affects a water supply by pollution or diminution as a result of gas or oil well drilling to restore or replace the affected water supply. Section 78.51 reflects current caselaw regarding an operator’s duty to replace or restore a water supply.

Section 78.51(d)(2) provides that a restored or replaced water supply must meet safe drinking water standards. If the pre-contamination water supply did not meet safe drinking water standards, the operator must restore or replace the contaminated water supply with a supply that is comparable to the water supply that existed prior to contamination.

Section 78.51(d)(1)(v) requires the operator to provide permanent payment for any increased cost to operate or maintain the restored or replaced water supply. Sections 78.51(d)(3)(i) and 78.51(d)(3)(ii) clarify that the replaced or restored water supply must be able to satisfy the water user’s needs.

The final form rulemaking modifies proposed § 78.51 (d) to provide uniform terms and add clarity and amends § 78.51(h), in response to public comment, providing that an operator who receives notice that a water supply has been affected by pollution or diminution must notify the Department within twenty-four hours of receiving that notice.

§ 78.52 Predrilling or prealteration survey.

Section 78.52(d) provides that an operator must provide the Department and the landowner or water purveyor with the results of their predrilling survey within ten business days of receiving the survey results. The final form rulemaking establishes that survey results not received within ten days may not be used to preserve the operator’s defenses under § 601.208(d)(1) of the Oil and Gas Act.

§ 78.55. Control and disposal plan.

Section 78.55(b) of the final form rulemaking establishes that an operator’s control and disposal plan must include a pressure barrier policy identifying the pressure barriers to be used during identified well drilling and completion operations. The final form rulemaking section 78.55(e) provides that an operator’s control and disposal plan must also contain a list of emergency contact phone numbers and that this list must also be displayed at the well site.

Section 78.55(d) of the final form rulemaking establishes that an operator’s control and disposal plan must be available at the well site during well drilling and completion operations.

§ 78.71. Use of safety devices—well casing.

Section 78.71(a) clarifies that the well control equipment must be attached to casing that is cemented in place.

§ 78.72. Use of safety devices—blow-out prevention equipment.

Section 78.72(a) of the final form rulemaking clarifies when blow-out equipment must be used. The final form rulemaking specifies that blow-out equipment must be must be used when drilling a well intending to produce from an unconventional formation and when drilling out solid core hydraulic fracturing plugs to complete a well.

Section 78.72(c) establishes that controls for the blow-out preventer must be accessible in case of an emergency. The final form rulemaking §78.72(c) specifies that controls for a blow-out preventer with a high pressure rating must be located at least 50 feet away from the drilling rig to assure accessibility in the event of loss of well control.

Section 78.72 (f) was amended to clarify when drilling must cease when blow-out prevention equipment is discovered to be in poor working order.

Section 78.72(h) of the final form rulemaking establishes that an individual with specified certifications must be at the well site when blow-out prevention equipment is being used and that those certifications must be available at the well site.

The final form rulemaking adds § 78.72(i), establishing that pressure barriers must be comprised of at least two mechanical pressure barriers between the open producing formation and the atmosphere. Additionally, these mechanical pressure barriers must be capable of being tested according to the manufacturers' specifications prior to operation. Moreover, if the operator has only one pressure barrier, operations must cease until additional pressure barriers are added or repaired and tested.

The final form rulemaking § 78.72(j) establishes that a hydraulic workover unit must be used during post-completion cleanout operations in unconventional formations.

The final form rulemaking specifies that intermediate casing must be cemented to surface, and now allows blow-out preventers to be attached to surface casing without regard to its length.

§ 78.73. General provision for well construction and operation.

Sections 78.73(a) and 78.73(b) further clarify that the well must be constructed and operated in a manner that protects public health and safety and the environment.

§ 78.73(c) reduces the allowable pressure that may be exerted on the surface and coal protective casing seats. The final form rulemaking clarifies how to calculate the pressure that must not be exceeded on the surface and coal protective casings. The final form rulemaking specifies that the pressure on the surface or coal protective casing seats is determined by measuring the surface shut-in pressure and the surface producing back pressure exerted on the surface or coal protective casing.

Section 78.73(e) was added in the proposed rulemaking, requiring excess gas encountered during drilling to be flared, captured or diverted away from the drilling rig. Section 78.73(f) was also added in the proposed rulemaking, requiring check flow valves that prevent backflow from the pipelines into the well.

§ 78.75a. Area of alternative methods.

The Oil and Gas Act provides that the Department may approve alternative methods for the casing, plugging or equipping of a well. Section 78.75a, added in the proposed rulemaking, establishes procedures by which the Department may on its own initiative designate an area of alternative methods – an area that requires alternative drilling, casing, equipping, or plugging methods to operate the well in a safe and environmentally protective manner. Establishing such an area requires notice in the Pennsylvania Bulletin and an opportunity for the public to comment.

§ 78.81. General provisions.

Section 78.81(c), which stated that certain sections of the regulation do not apply to production or intermediate casings, is deleted to reflect new casing requirements.

§ 78.82. Use of conductor pipe.

The final form rulemaking § 78.82 clarifies that conductor pipe is used to stabilize the top hole of a well and must be driven into place or cemented from the seat to the surface to prevent the infiltration of water or other fluids into the subsurface.

§ 78.83 Surface and coal protective casing and cementing procedures.

Section 78.83(a) prohibits the use of surface casing as production casing and requires an additional string of casing to be installed in a well unless the well is only used to produce oil that does not present a threat to groundwater or if the operator of a gas well demonstrates that all gas and fluids will be contained in the well and installs a working pressure gauge that can be inspected by the Department.

The final form rulemaking deletes § 78.83(c), which gave operators the ability to drill to producing zones prior to isolating the fresh groundwater under certain circumstances, and adds a new § 78.83(c), requiring the use of air or freshwater based fluids when drilling through the fresh groundwater zone. Additionally, final form rulemaking § 78.83(c) specifies that the surface casing must be set fifty feet below the deepest fresh groundwater or at least fifty feet into consolidated rock, but not more than 200 feet below the deepest fresh groundwater unless necessary to set the casing in consolidating rock. The final form rulemaking also establishes that the wellbore must be conditioned prior to cementing.

The final form rulemaking amends §§ 78.83(c), (f), (g) and (i), mandating the use of centralizers to position the surface casing, coal protective casing, and any additional fresh groundwater casings in the wellbore. Subsections (f) and (i) have been further amended to require the additional water string to be cemented to the surface as opposed to 20 feet into the surface or coal protective casing.

§ 78.83a. Casing and cementing plan.

Section 78.83a establishes that operators must develop a casing and cementing plan that is available for the Department to review at the well site. The plan must describe the casing to be used and the cementing practices to be employed. The Department may request a copy of the plan for review and approval prior to drilling.

The final form rulemaking amends § 78.83a(a)(1) and (a)(6), specifying that the operator must include in its casing and cementing plan the method or information by which the depth of the deepest fresh groundwater was determined and the proposed wellbore conditioning procedures.

§ 78.83b. Casing and cementing—lost circulation.

Section 78.83b(a), added on proposed rulemaking, requires operators to notify the Department when cement used to protect fresh groundwater is not returned to the surface despite pumping more than 120% of the estimated required volume. If cement is not returned to the surface, the operator must determine the top of the cement and additional casing must be run and cemented, unless the well only produces oil off a vented production pipe if approved by the Department. Final form rulemaking § 78.83b(a)(1) clarifies what the operator must do when this happens and what additional measures must be taken.

The final form rulemaking adds § 78.83b(b) which provides that, in the event of lost circulation, the operator may, in addition to § 78.83a(a)'s requirements, pump additional cement through a pour string from the surface to fill the annular space.

§ 78.83c. Intermediate and production casing.

Section 78.83c, added on proposed rulemaking, specifies the cementing requirements for intermediate and production casing and establishes the pressure limitation for wells that produce gas off the annulus of the intermediate casing string.

The final form rulemaking adds a new § 78.83c(a) to require the intermediate and production borehole to be prepared prior to cementing.

The final form rulemaking amends § 78.83c(b) to mandate the use of centralizers when cementing the intermediate casing and requires the intermediate casing to be cemented to the surface.

The final form rulemaking amends § 78.83c(c) to mandate the use of centralizers when cementing the production casing and further specifies how much cement must be used to cement production casing.

§ 78.84. Casing standards.

The substantial amendments to § 78.84 require specified pressure ratings or pressure testing for different types of casings. Final form rulemaking § 78.84(d)(3) clarifies the certification requirements for a person welding casing.

The final form rulemaking § 78.84(f) clarifies that if the casing attached to the blow-out preventer has a pressure rating of greater then 3,000 psi, it must be pressure tested after it is cemented. To pass this pressure test, the casing must able to hold the anticipated maximum pressure to which the casing will be exposed for thirty minutes with not more than a ten percent decrease.

§ 78.85. Cement standards.

Section 78.85 provides additional standards for well casing cement, as well as references to ASTM International and American Petroleum Institute standards.

The final form rulemaking amends § 78.85(a)(4) and deletes proposed § 78.85(a)(5), clarifying that cement must protect the casing from corrosion and degradation, including that the cement used for coal protective casing must be formulated to withstand elevated sulfate concentrations in the surrounding wellbore. The final form rulemaking new § 78.85(a)(5) specifies that gas block additives and low fluid loss slurries must be used in areas of known shallow gas producing zones.

The final form rulemaking amends § 78.85(b) by adding requirements regarding surface casing cement. This subsection specifies that the cement at the bottom 300 feet of the surface casing constitutes a zone of critical cement, meaning that the cement in this zone must achieve a seventy-two hour compressive strength of 1,200 psi and the free water separation must not be more than six milliliters per 250 milliliters of cement.

The final form rulemaking amends § 78.85(c) by clarifying the actions that are prohibited during the mandatory eight-hour wait time on the cement for all casings.

The final form rulemaking § 78.85(f) specifies the information that must be included in the operator’s cement job log.

§ 78.88. Mechanical integrity of operating well.

Section 78.88, added on proposed rulemaking, requires operators to inspect their wells at least quarterly for signs of physical degradation in addition to determining whether the pressure in the well is within allowable limits. Wells that fail inspection must be attended to immediately and the Department must be notified.

§ 78.89. Gas migration response.

Section 78.89 is substantially amended in the final form rulemaking to specify the actions an operator must take in the event of a gas migration incident. Section 78.89(a) of the final form rulemaking requires an operator to conduct an investigation immediately after it is notified or otherwise made aware of a potential gas migration incident to assess the nature of the incident, assess any potential hazards, and mitigate any hazards. Section 78.89(b) of the final form rulemaking specifies that the investigation must consist of a site visit, an interview of the complainant, a field survey, and if necessary, monitoring locations must be established. If the operator detects a high concentration of combustible gas inside a building or structure, the final-form rulemaking § 78.89(c) establishes that the operator must immediately notify the Department and local emergency response agencies, initiate mitigation measures and conduct further investigation and monitoring of the surrounding area.

Section 78.89(d) of the final form rulemaking specifies that if sustained detectable concentrations of combustible gas are detected at certain specified levels, the operator must notify the Department and take measures to ensure public health and safety. If the operator conducts an investigation and is not required to take the measures outlined in §§78.89(c) or (d), § 78.89(f) requires the operator to conduct additional monitoring, document its findings, and submit a report.

The final form rulemaking adds § 78.89(e) which establishes that the Department may require the operator to take additional investigative and monitoring measures in the event of a reported natural gas migration incident. The final form rulemaking §§ 78.89(g)-(i) provide additional notification and reporting requirements.

§§ 78.92–78.95. Plugging.

Sections 78.92–78.95 incorporate the substantive requirements of the eliminated definition of “retrievable” along with requiring an additional attempt to remove uncemented casing prior to plugging a well. The revised sections also require cement to be placed across the formerly producing formation as opposed to placing the cement plug on top of the formation as is the current requirement.

§ 78.96. Marking the location of a plugged well.

Section 78.96(a) permits the use of materials other than cement and metal to mark and hold a marker for a plugged well.

§ 78.121. Well record and completion report.

Section 78.121 incorporates the requirements of Act 15 of 2010 which mandate semi-annual production reporting of Marcellus Shale wells. In § 78.121(a), the dates are amended to reflect Act 15’s requirements. Because Act 15 also requires the Department to post the production of Marcellus Shale wells on the Department’s website, § 78.121(b) is amended to require that the production reports be submitted electronically.

§ 78.122. Well record and completion report.

Section 78.122(a)(10) requires the operator to certify that the well has been properly constructed. The final form rulemaking amends § 78.122(b)(6), requiring the operator to submit additional information in its completion report's stimulation record, including a descriptive list of the chemical additives used in the stimulation fluid, the percent by volume of those chemical additives, a list of the hazardous chemicals used in the stimulation fluid, the percent by volume of those hazardous chemicals, the total volume or water used and a list of the water sources used pursuant to an approved water management plan. The final form rulemaking § 78.122(c) provides that a well operator may designate any trade secrets or confidential proprietary information in the completion report and the Department will prevent disclosure of confidential information to the extent permitted by the Right to Know Law, 65 P.S. 67.101 *et seq.* Additionally, § 78.122(d) specifies that the operator must maintain records of every chemical used to hydraulically fracture the well and provide those records to the Department upon request.

G. Benefits, Costs and Compliance

Benefits

Both the residents of this Commonwealth and the regulated community will benefit from this regulation

The public will benefit in several ways. The updated casing and cementing requirements will provide an increased degree of protection for homeowners and both public and private water supplies. The construction standards will align Pennsylvania's regulations with other states' rules as well as current industry standards. Pressure testing the casing and testing surface casing seats will detect construction deficiencies before a well could create a potential safety or environmental problem. Minimizing annular pressure will reduce the potential for gas migration. The new quarterly inspections and annual reporting will be a vital tool for operators to use in detecting potential safety or environmental impacts before they may become an issue. The proposed regulations also outline the procedures the operator and the Department will utilize if there is a reported gas migration incident.

The new construction standards and the well remediation measures will far outweigh the liability to the operator from the potential impacts to public safety and harm to the environment from gas migration or from polluting water resources that may result without these additional precautions. As new areas of the Commonwealth are developed for natural gas, these proposed regulations will avoid many potential health, safety and environmental issues.

Compliance Costs

This rulemaking will impose minimal additional cost on the Department. This proposal will help the Department offset potential health, safety and environmental issues.

The Department finds that most gas migration issues stem from inadequate cementing procedures, cement returns, or combinations of inadequate casing and cementing or over-pressured casing seats. Because many of the Marcellus Shall well operators meet or exceed the current well casing and cementing regulations, any increased cost associated with drilling and operating oil and gas wells will be minimal. All of the potential increases in cost to an operator will be associated with assuring a well is properly completed, operated and plugged.

The potential increase in cost is minor when compared to the overall cost of well construction. Where cement is not returned to the surface or when excessive pressure is placed on the surface casing seat, the revised regulations require the operator to install an additional string of casing. The construction cost for the additional string of casing is about $10,000 per well.

Some commentators questioned the Department's estimate for the additional string of casing, stating that the cost of an additional casing string is much more than $10,000 per well, and is more likely on the order of $300,000 to $500,000 per well, depending on depth and area. The commentators stated that if the additional string of casing is justified from a technical standpoint, then it is the correct course of action. But nowhere do the proposed regulations provide a technical justification for an additional casing string.

The added expense described by the commentators does not apply to situations where cement is not returned to the surface. Where production casing is run and set on a packer or casing is set 50 feet deeper than the surface casing, the Department's estimate is sound. Instead, the scenario described more directly relates to the Board's decision to prohibit operators from comingling fresh groundwater with brine by setting very deep surface casing. By setting deep surface casing, operators avoid using deeper intermediate casing and costly cement and cementing practices.

The proposed casing design advocated by the commentators has resulted in several recent gas migration cases in Pennsylvania. These gas migration cases threaten the lives and safety of the citizens of the Commonwealth. The Board did not consider the expense of an intermediate string of casing when it crafted the regulations because the casing design advocated by the commentator results in an unlawful condition. Prohibiting gas migration is the cornerstone of these regulations and compromising on the issue to save money on a necessary string of casing is not acceptable.

Used casing, welded casing and casing attached to a blow-out preventer must be pressure tested to demonstrate its ability to withstand the highest anticipated working pressures to which the casing will be exposed. If the casing fails this test, the operator must repair of replace the casing and ultimately pass the pressure test. The cost to repair or replace the defective casing is completely outweighed by the environmental damage that would result from a failed string of casing and the fact that the casing would still need to be repaired or replaced.

The typical cost to develop a Marcellus Shale well is around $5,000,000. The additional cost of compliance would only be approximately 0.2% of the overall cost to develop a Marcellus Shale well.

The typical cost to develop a shallow gas well is $250,000 and the typical cost to develop an oil well is $200,000. In either situation, the additional cost of compliance would only be approximately 4% to 5% of the overall cost of the well.

All of the additional measures are proposed to reduce the potential for gas migration. If an operator fails to prevent a pollution event of a water supply, the anticipated cost to permanently replace one private water supply would be approximately $4,000 to drill a new water well or $30,000 to provide and permanently pay for a treatment system.

Compliance Assistance Plan

The Department has worked extensively with representatives from the regulated community and leaders the several trade organizations. The requirements of this regulation are, therefore, well known.

The Department, however, several scheduled training sessions for the regulated community to address the Department's regulatory requirements. The Department will use these training sessions as an opportunity to further education the industry about the new requirements.

Paperwork Requirements

The annual well inspection report, the semi-annual production report mandated by Act 15 for operators of Marcellus Shale wells and the additional information required in the completion report will require submittal of two additional forms and additional information on an existing form. The results of gas migration investigations will also require additional reporting obligations.

H. Pollution Prevention

The Federal Pollution Prevention Act of 1990 established a national policy that promotes pollution prevention as the preferred means for achieving state environmental protection goals. The Department encourages pollution prevention, which is the reduction or elimination of pollution at its source, through the substitution of environmentally friendly materials, more efficient use of raw materials, or the incorporation of energy efficiency strategies. Pollution prevention practices can provide greater environmental protection with greater efficiency because they can result in significant cost savings to facilities that permanently achieve or move beyond compliance. This regulation has incorporated the following pollution prevention provisions and incentives:

This regulation will minimize gas migration and will provide an increased degree of protection for both public and private water supplies by updating material specifications and performance testing as well as adding more specific design, construction, operational an monitoring requirements. The plugging, water supply replacement, and gas migrations reporting regulations have been amended to ensure that public safety and groundwater are protected.

I. Sunset Review

This regulation will be reviewed in accordance with the sunset review schedule published by the Department to determine whether the regulation effectively fulfills the goals for which it was intended.

J. Regulatory Review

Under section 5(a) of the Regulatory Review Act (71 P.S. § 745.5(a)), on June 25, 2010, the Department submitted a copy of the notice of proposed rulemaking, published at 40 *Pa.B.* 3845, to the Independent Regulatory Review Commission (IRRC) and the Chairpersons of the House and Senate Environmental Resources and Energy Committees for review and comment.

Under section 5(c) of the Regulatory Review Act, IRRC and the Committees were provided with copies of the comments received during the public comment period, as well as other documents when requested. In preparing these final form regulations, the Department has considered all comments from IRRC, the Committees and the public.

Under section 5.1(j.2) of the Regulatory Review Act, on ___(blank)___, these final form regulations were deemed approved by the House and Senate Committees. Under section 5.1(e) of the Regulatory Review Act, IRRC met on ____(blank)____ and approved the final form regulations.

K. Findings of the Board

The Board finds that:

(1) Public notice of proposed rulemaking was given under sections 201 and 202 of the act of July 31, 1968 (P.L. 769, No. 240) (45 P.S. §§ 1201 and 1202) and regulations promulgated thereunder at *1 Pennsylvania Code* §§ 7.1 and 7.2.

(2) A public comment period was provided as required by law, and all comments were considered.

(3) These regulations do not enlarge the purpose of the proposal published at 40 *Pa.B.* 3845.

(4) These regulations are necessary and appropriate for administration and enforcement of the authorizing acts identified in Section C of this order.

L. Order of the Board

The Board, acting under the authorizing statutes, orders that:

(1) The regulations of the Department of Environmental Protection, *25 Pennsylvania Code*, Chapter 78 are amended to read as set forth in Annex A.

(2) The Chairperson of the Board shall submit this order and Annex A to the Office of General Counsel and the Office of Attorney General for review and approval as to legality and form, as required by law.

(3) The Chairperson of the Board shall submit this order and Annex A to the Independent Regulatory Review Commission and the Senate and House Environmental Resources and Energy Committees as required by the Regulatory Review Act.

(4) The Chairperson of the Board shall certify this order and Annex A and deposit them with the Legislative Reference Bureau, as required by law.

(5) This order shall take effect immediately upon publication in the *Pennsylvania Bulletin*.

BY:

JOHN HANGER
Chairperson
Environmental Quality Board

Notice of Final Rulemaking
Department of Environmental Protection
Environmental Quality Board
25 *Pa. Code,* Chapter 78
Oil and Gas Well Cementing and Casing

Order

The Environmental Quality Board (Board) by this order amends 25 *Pa. Code*, Chapter 78 (relating to oil and gas well requirements) as set forth in Annex A.

Properly constructed and operated oil and gas wells are critical to protecting water supplies and public safety. If a well is not properly cased and cemented, natural gas in subsurface formations may potentially migrate from the wellbore through bedrock and soil. This stray gas may adversely affect water supplies, as well as accumulate in or adjacent to structures such as residences and water wells. Under certain conditions, stray gas has the potential to cause a fire or explosion. These situations present a serious threat to public health and safety as well as the environment. The purpose of this final rulemaking is to improve drilling, casing, cement, testing, monitoring and plugging requirements for oil and gas wells to minimize gas migration and protect water supplies.

The final form rulemaking differs from the proposed rulemaking in several important respects. The differences reflect the concerns raised by the regulated community and the public, resulting in an improved rule. The changes to the final form rulemaking strengthen well design requirements to prevent gas migration incidents.

The significant revisions to the final form rulemaking include: the addition of a provision that requires operators to have a pressure barriers plan to minimize well control events; the addition of a provision that requires operators to keep a list of emergency contact phone numbers at the well site; amended provisions that clarify how and when blow-out prevention equipment is to be installed and operated; the addition of a provision that requires operators to condition the wellbore to ensure an adequate bond between the cement, casing and the formation; the addition of provisions that require the use of centralizers to ensure that casings are properly positioned in the wellbore; the addition of a provision that improves the quality of the cement placed in the casing that protects fresh groundwater; the addition of provisions that specify the actions an operator must take in the event of a gas migration incident; and revisions to the reporting requirements for chemicals used to hydraulically fracture a well.

This order was adopted by the Board at its meeting of ________(blank)______.

A. Effective Date

These amendments will go into effect upon publication in the *Pennsylvania Bulletin* as final rulemaking.

B. Contact Persons

For further information contact Scott R. Perry, Director, Bureau of Oil and Gas Management, Rachel Carson State Office Building, 5th Floor, P.O. Box 8765, Harrisburg, PA 17105-8461, (717) 772-2199; or Elizabeth A. Nolan, Assistant Counsel, Bureau of Regulatory Counsel, Rachel Carson State Office Building, 9th Floor, P.O. Box 8464, Harrisburg, PA 17105-8464, (717) 787-7060. Persons with a disability may use the AT&T Relay Service by calling (800) 654-5984 (TDD users) or (800) 654-5988 (voice users). This final form rulemaking is available on the Department of Environmental Protection's website at http://www.dep.state.pa.us

C. Statutory Authority

The final form rulemaking is being made under the authority of Section 604 of the Oil and Gas Act (58 P.S. § 601.604), which directs the Board to adopt regulations necessary to implement the Act, and Section 1917-A and 1920-A of the Administrative Code (71 P.S. §§ 510-17 and 510-20). Section 1917-A authorizes and requires the Department to protect the people of this Commonwealth from unsanitary conditions and other nuisances, including any condition that is declared to be a nuisance by any law administered by the Department. Section 1920-A authorizes the Board to promulgate regulations of the Department.

D. Background of the Amendments

Many of the regulations governing well construction and water supply replacement were promulgated in July 1989 and remained largely unchanged until this rulemaking. Since that time, recent advances in drilling technology have attracted interest in producing natural gas from the Marcellus Shale, a rock formation that underlies approximately two-thirds of Pennsylvania. New well drilling and completion practices now employed to extract natural gas from the Marcellus Shale and other similar shale formations in Pennsylvania, as well as several recent incidents of contaminated drinking water caused by traditional and Marcellus Shale wells resulted in the Department's decision to re-evaluate the existing well construction requirements.

It was determined that the existing regulations were not specific enough in detailing the Department's expectations of a properly cased and cemented well, especially in light of the new techniques used by Marcellus Shale operators. The Department also determined that the existing regulations did not address the need for an immediate response by operators to a gas migration complaint and did not require routine inspection of existing wells by the operator.

The final rulemaking contains revised design, construction, operational, monitoring, plugging, water supply replacement, and hydraulic fracturing reporting requirements. The final rulemaking also provides material specifications and performance testing to ensure the proper casing, cementing and operation of a well. Additionally, the final rulemaking contains new provisions that require routine inspection of wells and outline the actions an operator and the Department must take in the event of a gas migration incident.

The proposed rulemaking was published in the *Pennsylvania Bulletin* on July 10, 2010. See 40 *Pa.B.* 3845 (July 10, 2010). The public comment period closed on August 9, 2010. In addition, five public hearings were held: July 19, 2010, in Tunkhannock, PA; July 21, 2010, in Williamsport, PA; July 22, 2010, in Meadville, PA; July 22, 2010, in Pittsburgh, PA; and July 26, 2010, in Pittsburgh, PA.

Prior to recommending that the proposed regulations be offered to the Environmental Quality board, the Oil and Gas Technical Advisory board (TAB) formed a technical subcommittee with representatives from various companies, trade groups and consultants to review and provide comments on the proposed rulemaking. The Department met with TAB and this subcommittee on October 28, 2009, January 14, 2010, January 21, 2010 and March 25, 2010.

The Department presented the draft final form rulemaking to TAB on September 16, 2010. During this discussion, TAB members made several recommendations regarding the definition of unconventional formations, use of blow-out preventers, cementing the intermediate casing, producing gas off the intermediate casing, and the actions the operator must take when it loses circulation of cement. At the conclusion of the meeting, TAB members were not able to endorse nor disapprove the rulemaking and instead expressed an interest in having the TAB subcommittee review the amendments to the final form rulemaking.

E. Summary of Comments and Responses

The Board received approximately 2,000 comments regarding the proposed Oil and Gas Well Casing and Cementing regulations during the public hearings and public comment period. Many of the comments received sought clarification or additional protective measures. The majority of comments were supportive of the proposal.

Several commentators made suggestions seeking to clarify the definition of "deepest fresh groundwater, including suggesting that the term be defined with reference to certain levels of total dissolved solids (TDS) ranging from 500 to 10,000 mg/l TDS. The Board appreciated these comments, but decided that numerical criteria should not be used to define deepest fresh groundwater because many water supplies provide water that exceed the 500 mg/l drinking water standard, but 10,000 mg/l is far too saline for Pennsylvania drinking water supplies. It is critical that the casing be set deep enough to isolate usable water supplies but not so deep that brine be permitted to co-mingle with fresh groundwater. It is also important to recognize that testing water produced during drilling will not yield accurate test results. For these reasons, the final form rulemaking has been amended to require operators to identify how the deepest fresh groundwater was determined and record the information in the casing and cementing plan.

Many commentators sought clarification regarding the provisions that require an operator who affects a water supply to restore or replace the affected water supply with an alternate supply adequate in quantity and quality for the purposes served by the supply. The amendments to § 78.51 reflect the Department's interpretation of an adequate alternate water supply according to recent caselaw.

Several commentators suggest that all replaced or restored water should meet safe drinking water standards. The Board deems a supply adequate if it meets safe drinking water standards or is comparable to the unaffected water supply if that water supply didn't meet those standards.

A commentator was uncertain about who would determine reasonable foreseeable uses. The regulation states that it is the duty of the Department to determine if the operator is in compliance with this subsection.

Additionally, several commentators were concerned that § 78.51(h) did not provide a timely response for affected water supplies. The Board agrees and amends § 78.51(h) to require operators to notify the Department within 24 hours of receiving a report that a water supply has been affected by pollution of diminution caused by drilling activities.

Several commentators objected to the provisions that would allow the use of used pipe. The Board considers used casing to be acceptable in certain applications, notably in low pressured shallow oil wells that do not produce gas. In these instances, used casing has been utilized successfully and has been shown to be suitable for long-term use in these applications. All used casing, however, is subject to the casing integrity requirement of § 78.84(b), as well as new requirements for pressure testing in § 78.84(c).

Many commentators suggested amendments to § 78.85(b) that would require a 72-hour compressive strength standard of at least 1,200 psi across critical zones of cement at the bottom of the casing seat where the highest pressures and stresses are likely to be encountered and in places where the well bore passes through aquifers and drinking water. The Board agrees and has amended §78.85(b) to require a zone of critical cement at the surface casing seat which must achieve a 72-hour compressive strength of 1200 psi and have a free-water separation of no more than six milliliters per 250 milliliters of cement.

Several commentators suggest that the cement ticket include testing of pH, temperature, and a record of the wait on cement time. The Board agrees and the regulation has been revised accordingly.

Some commentators objected to the quarterly mechanical integrity inspections required by §78.88(a), arguing that the requirement is excessive. While several commentators believed that quarterly inspections were not enough, other commentators supported § 78.88(a) quarterly inspection requirements. The Board has decided that quarterly inspections are sufficient to ensure that well pressures are within allowable limits and the casing is structurally sound. The Board does not consider quarterly mechanical integrity testing to be excessive. Rather, the inspections provide the operator an opportunity to correct problems at the well before such problems create a condition that will require significant time and expense to address. The Board has also determined that required evaluation of the well does not include invasive procedures.

Several commentators made suggestions to § 78.89 regarding the gas migration response requirements, including a provision requiring immediate notification to the Department. The Board agrees and has amended the final form rulemaking to require the operator to immediately conduct an investigation and contact the Department.

Commentators suggested that operators conduct an initial response action to determine the nature of the incident, assess the potential for hazards to public health and safety, and mitigate any hazard posed by the concentration of stray natural gas in the environment. Commentators suggested what the investigation include a site visit and an interview of the complainant. Commentators suggested that the actions that an operator must take in the event of a reported gas migration incident be delineated by the concentration of combustible gas detected in the investigation. Commentators also suggested other additional investigation and mitigation measures that operators should be required to take, including a field survey, the collection of gas and/or water samples, the establishment of monitoring locations, and an evaluation of the operator's adjacent wells. Commentators also suggested certain reporting requirements following a reported gas migration incident. The Board agrees with many of the commentators suggestions and has revised § 78.89. These changes largely follow the commentators' suggestions. The revisions also require continued monitoring of gas migration complaints where the levels of dissolved methane in the water supply exceed 7 milligrams per liter. This level is based on 25% of the capacity of water to contain dissolved methane under one atmosphere of pressure. This number is much more certain and scientifically based than the unknown "background" level proposed by the commentator.

Commentators suggested that the information required in the completion report's stimulation record be expanded to require more specific information, including information regarding the chemical additives used and a the chemicals listed in the operator's Material Safety Data Sheets by Chemical Abstract Number. Other commentators object to requirements that require operators to submit confidential information and suggest that the issue of confidentiality be addressed in § 78.122. The Board has expanded the stimulation record requirements in subsection §78.122(b)(6) to include the Chemical Abstract Number for each Material Safety Data Sheet-listed hydraulic fracturing chemical used, as well as the percent (by volume) of each listed chemical used. The Board has also amended this subsection allowing the designation of confidential or trade secret information. The Department shall prevent disclosure of such designated confidential information to the extent permitted by the Right To Know Law, 65 P.S. 67.101 et seq.

F. Summary of Final Form Regulation and Changes from Proposed to Final Form Rulemaking

§ 78.1. Definitions.

Section 78.1 amends the definitions of the following terms to improve clarity or to explain new or existing provisions: "casing seat," "cement" and "surface casing." Section 78.1 also adds definitions for the following terms to explain new or existing provisions within Chapter 78: "cement job log," "conductor pipe" and "intermediate casing."

The final form rulemaking amends the following definitions listed above in response to public comment to improve clarity: "casing seat," "cement job log," "intermediate casing" and "surface casing."

Section 78.1 removes the definition of "retrievable" and inserts the substantive portion of the definition into the appropriate plugging regulations.

The final form rulemaking § 78.1 adds definitions for "L.E.L" and "unconventional formation."

§ 78.51. Protection of water supplies.

The Oil and Gas Act requires an operator who affects a water supply by pollution or diminution as a result of gas or oil well drilling to restore or replace the affected water supply. Section 78.51 reflects current caselaw regarding an operator's duty to replace or restore a water supply.

Section 78.51(d)(2) provides that a restored or replaced water supply must meet safe drinking water standards. If the pre-contamination water supply did not meet safe drinking water standards, the operator must restore or replace the contaminated water supply with a supply that is comparable to the water supply that existed prior to contamination.

Section 78.51(d)(1)(v) requires the operator to provide permanent payment for any increased cost to operate or maintain the restored or replaced water supply. Sections 78.51(d)(3)(i) and 78.51(d)(3)(ii) clarify that the replaced or restored water supply must be able to satisfy the water user's needs.

The final form rulemaking modifies proposed § 78.51 (d) to provide uniform terms and add clarity and amends § 78.51(h), in response to public comment, providing that an operator who receives notice that a water supply has been affected by pollution or diminution must notify the Department within twenty-four hours of receiving that notice.

§ 78.52 Predrilling or prealteration survey.

Section 78.52(d) provides that an operator must provide the Department and the landowner or water purveyor with the results of their predrilling survey within ten business days of receiving the survey results. The final form rulemaking establishes that survey results not received within ten days may not be used to preserve the operator's defenses under § 601.208(d)(1) of the Oil and Gas Act.

§ 78.55. Control and disposal plan.

Section 78.55(b) of the final form rulemaking establishes that an operator's control and disposal plan must include a pressure barrier policy identifying the pressure barriers to be used during identified well drilling and completion operations. The final form rulemaking section 78.55(e) provides that an operator's control and disposal plan must also contain a list of emergency contact phone numbers and that this list must also be displayed at the well site.

Section 78.55(d) of the final form rulemaking establishes that an operator's control and disposal plan must be available at the well site during well drilling and completion operations.

§ 78.71. Use of safety devices—well casing.

Section 78.71(a) clarifies that the well control equipment must be attached to casing that is cemented in place.

§ 78.72. Use of safety devices—blow-out prevention equipment.

Section 78.72(a) of the final form rulemaking clarifies when blow-out equipment must be used. The final form rulemaking specifies that blow-out equipment must be must be used when drilling a well intending to produce from an unconventional formation and when drilling out solid core hydraulic fracturing plugs to complete a well.

Section 78.72(c) establishes that controls for the blow-out preventer must be accessible in case of an emergency. The final form rulemaking §78.72(c) specifies that controls for a blow-out preventer with a high pressure rating must be located at least 50 feet away from the drilling rig to assure accessibility in the event of loss of well control.

Section 78.72 (f) was amended to clarify when drilling must cease when blow-out prevention equipment is discovered to be in poor working order.

Section 78.72(h) of the final form rulemaking establishes that an individual with specified certifications must be at the well site when blow-out prevention equipment is being used and that those certifications must be available at the well site.

The final form rulemaking adds § 78.72(i), establishing that pressure barriers must be comprised of at least two mechanical pressure barriers between the open producing formation and the atmosphere. Additionally, these mechanical pressure barriers must be capable of being tested according to the manufacturers' specifications prior to operation. Moreover, if the operator has only one pressure barrier, operations must cease until additional pressure barriers are added or repaired and tested.

The final form rulemaking § 78.72(j) establishes that a hydraulic workover unit must be used during post-completion cleanout operations in unconventional formations.

The final form rulemaking specifies that intermediate casing must be cemented to surface, and now allows blow-out preventers to be attached to surface casing without regard to its length.

§ 78.73. General provision for well construction and operation.

Sections 78.73(a) and 78.73(b) further clarify that the well must be constructed and operated in a manner that protects public health and safety and the environment.

§ 78.73(c) reduces the allowable pressure that may be exerted on the surface and coal protective casing seats. The final form rulemaking clarifies how to calculate the pressure that must not be exceeded on the surface and coal protective casings. The final form rulemaking specifies that the pressure on the surface or coal protective casing seats is determined by measuring the surface shut-in pressure and the surface producing back pressure exerted on the surface or coal protective casing.

Section 78.73(e) was added in the proposed rulemaking, requiring excess gas encountered during drilling to be flared, captured or diverted away from the drilling rig. Section 78.73(f) was also added in the proposed rulemaking, requiring check flow valves that prevent backflow from the pipelines into the well.

§ 78.75a. Area of alternative methods.

The Oil and Gas Act provides that the Department may approve alternative methods for the casing, plugging or equipping of a well. Section 78.75a, added in the proposed rulemaking, establishes procedures by which the Department may on its own initiative designate an area of alternative methods – an area that requires alternative drilling, casing, equipping, or plugging methods to operate the well in a safe and environmentally protective manner. Establishing such an area requires notice in the Pennsylvania Bulletin and an opportunity for the public to comment.

§ 78.81. General provisions.

Section 78.81(c), which stated that certain sections of the regulation do not apply to production or intermediate casings, is deleted to reflect new casing requirements.

§ 78.82. Use of conductor pipe.

The final form rulemaking § 78.82 clarifies that conductor pipe is used to stabilize the top hole of a well and must be driven into place or cemented from the seat to the surface to prevent the infiltration of water or other fluids into the subsurface.

§ 78.83 Surface and coal protective casing and cementing procedures.

Section 78.83(a) prohibits the use of surface casing as production casing and requires an additional string of casing to be installed in a well unless the well is only used to produce oil that does not present a threat to groundwater or if the operator of a gas well demonstrates that all gas and fluids will be contained in the well and installs a working pressure gauge that can be inspected by the Department.

The final form rulemaking deletes § 78.83(c), which gave operators the ability to drill to producing zones prior to isolating the fresh groundwater under certain circumstances, and adds a new § 78.83(c), requiring the use of air or freshwater based fluids when drilling through the fresh groundwater zone. Additionally, final form rulemaking § 78.83(c) specifies that the surface casing must be set fifty feet below the deepest fresh groundwater or at least fifty feet into consolidated rock, but not more than 200 feet below the deepest fresh groundwater unless necessary to set the casing in consolidating rock. The final form rulemaking also establishes that the wellbore must be conditioned prior to cementing.

The final form rulemaking amends §§ 78.83(c), (f), (g) and (i), mandating the use of centralizers to position the surface casing, coal protective casing, and any additional fresh groundwater casings in the wellbore. Subsections (f) and (i) have been further amended to require the additional water string to be cemented to the surface as opposed to 20 feet into the surface or coal protective casing.

§ 78.83a. Casing and cementing plan.

Section 78.83a establishes that operators must develop a casing and cementing plan that is available for the Department to review at the well site. The plan must describe the casing to be used and the cementing practices to be employed. The Department may request a copy of the plan for review and approval prior to drilling.

The final form rulemaking amends § 78.83a(a)(1) and (a)(6), specifying that the operator must include in its casing and cementing plan the method or information by which the depth of the deepest fresh groundwater was determined and the proposed wellbore conditioning procedures.

§ 78.83b. Casing and cementing—lost circulation.

Section 78.83b(a), added on proposed rulemaking, requires operators to notify the Department when cement used to protect fresh groundwater is not returned to the surface despite pumping more than 120% of the estimated required volume. If cement is not returned to the surface, the operator must determine the top of the cement and additional casing must be run and cemented, unless the well only produces oil off a vented production pipe if approved by the Department. Final form rulemaking § 78.83b(a)(1) clarifies what the operator must do when this happens and what additional measures must be taken.

The final form rulemaking adds § 78.83b(b) which provides that, in the event of lost circulation, the operator may, in addition to § 78.83a(a)'s requirements, pump additional cement through a pour string from the surface to fill the annular space.

§ 78.83c. Intermediate and production casing.

Section 78.83c, added on proposed rulemaking, specifies the cementing requirements for intermediate and production casing and establishes the pressure limitation for wells that produce gas off the annulus of the intermediate casing string.

The final form rulemaking adds a new § 78.83c(a) to require the intermediate and production borehole to be prepared prior to cementing.

The final form rulemaking amends § 78.83c(b) to mandate the use of centralizers when cementing the intermediate casing and requires the intermediate casing to be cemented to the surface.

The final form rulemaking amends § 78.83c(c) to mandate the use of centralizers when cementing the production casing and further specifies how much cement must be used to cement production casing.

§ 78.84. Casing standards.

The substantial amendments to § 78.84 require specified pressure ratings or pressure testing for different types of casings. Final form rulemaking § 78.84(d)(3) clarifies the certification requirements for a person welding casing.

The final form rulemaking § 78.84(f) clarifies that if the casing attached to the blow-out preventer has a pressure rating of greater then 3,000 psi, it must be pressure tested after it is cemented. To pass this pressure test, the casing must able to hold the anticipated maximum pressure to which the casing will be exposed for thirty minutes with not more than a ten percent decrease.

§ 78.85. Cement standards.

Section 78.85 provides additional standards for well casing cement, as well as references to ASTM International and American Petroleum Institute standards.

The final form rulemaking amends § 78.85(a)(4) and deletes proposed § 78.85(a)(5), clarifying that cement must protect the casing from corrosion and degradation, including that the cement used for coal protective casing must be formulated to withstand elevated sulfate concentrations in the surrounding wellbore. The final form rulemaking new § 78.85(a)(5) specifies that gas block additives and low fluid loss slurries must be used in areas of known shallow gas producing zones.

The final form rulemaking amends § 78.85(b) by adding requirements regarding surface casing cement. This subsection specifies that the cement at the bottom 300 feet of the surface casing constitutes a zone of critical cement, meaning that the cement in this zone must achieve a seventy-two hour compressive strength of 1,200 psi and the free water separation must not be more than six milliliters per 250 milliliters of cement.

The final form rulemaking amends § 78.85(c) by clarifying the actions that are prohibited during the mandatory eight-hour wait time on the cement for all casings.

The final form rulemaking § 78.85(f) specifies the information that must be included in the operator's cement job log.

§ 78.88. Mechanical integrity of operating well.

Section 78.88, added on proposed rulemaking, requires operators to inspect their wells at least quarterly for signs of physical degradation in addition to determining whether the pressure in the well is within allowable limits. Wells that fail inspection must be attended to immediately and the Department must be notified.

§ 78.89. Gas migration response.

Section 78.89 is substantially amended in the final form rulemaking to specify the actions an operator must take in the event of a gas migration incident. Section 78.89(a) of the final form rulemaking requires an operator to conduct an investigation immediately after it is notified or otherwise made aware of a potential gas migration incident to assess the nature of the incident, assess any potential hazards, and mitigate any hazards. Section 78.89(b) of the final form rulemaking specifies that the investigation must consist of a site visit, an interview of the complainant, a field survey, and if necessary, monitoring locations must be established. If the operator detects a high concentration of combustible gas inside a building or structure, the final-form rulemaking § 78.89(c) establishes that the operator must immediately notify the Department and local emergency response agencies, initiate mitigation measures and conduct further investigation and monitoring of the surrounding area.

Section 78.89(d) of the final form rulemaking specifies that if sustained detectable concentrations of combustible gas are detected at certain specified levels, the operator must notify the Department and take measures to ensure public health and safety. If the operator conducts an investigation and is not required to take the measures outlined in §§78.89(c) or (d), § 78.89(f) requires the operator to conduct additional monitoring, document its findings, and submit a report.

The final form rulemaking adds § 78.89(e) which establishes that the Department may require the operator to take additional investigative and monitoring measures in the event of a reported natural gas migration incident. The final form rulemaking §§ 78.89(g)-(i) provide additional notification and reporting requirements.

§§ 78.92–78.95. Plugging.

Sections 78.92–78.95 incorporate the substantive requirements of the eliminated definition of "retrievable" along with requiring an additional attempt to remove uncemented casing prior to plugging a well. The revised sections also require cement to be placed across the formerly producing formation as opposed to placing the cement plug on top of the formation as is the current requirement.

§ 78.96. Marking the location of a plugged well.

Section 78.96(a) permits the use of materials other than cement and metal to mark and hold a marker for a plugged well.

§ 78.121. Well record and completion report.

Section 78.121 incorporates the requirements of Act 15 of 2010 which mandate semi-annual production reporting of Marcellus Shale wells. In § 78.121(a), the dates are amended to reflect Act 15's requirements. Because Act 15 also requires the Department to post the production of Marcellus Shale wells on the Department's website, § 78.121(b) is amended to require that the production reports be submitted electronically.

§ 78.122. Well record and completion report.

Section 78.122(a)(10) requires the operator to certify that the well has been properly constructed. The final form rulemaking amends § 78.122(b)(6), requiring the operator to submit additional information in its completion report's stimulation record, including a descriptive list of the chemical additives used in the stimulation fluid, the percent by volume of those chemical additives, a list of the hazardous chemicals used in the stimulation fluid, the percent by volume of those hazardous chemicals, the total volume or water used and a list of the water sources used pursuant to an approved water management plan. The final form rulemaking § 78.122(c) provides that a well operator may designate any trade secrets or confidential proprietary information in the completion report and the Department will prevent disclosure of confidential information to the extent permitted by the Right to Know Law, 65 P.S. 67.101 *et seq.* Additionally, § 78.122(d) specifies that the operator must maintain records of every chemical used to hydraulically fracture the well and provide those records to the Department upon request.

G. Benefits, Costs and Compliance

Benefits

Both the residents of this Commonwealth and the regulated community will benefit from this regulation

The public will benefit in several ways. The updated casing and cementing requirements will provide an increased degree of protection for homeowners and both public and private water supplies. The construction standards will align Pennsylvania's regulations with other states' rules as well as current industry standards. Pressure testing the casing and testing surface casing seats will detect construction deficiencies before a well could create a potential safety or environmental problem. Minimizing annular pressure will reduce the potential for gas migration. The new quarterly inspections and annual reporting will be a vital tool for operators to use in detecting potential safety or environmental impacts before they may become an issue. The proposed regulations also outline the procedures the operator and the Department will utilize if there is a reported gas migration incident.

The new construction standards and the well remediation measures will far outweigh the liability to the operator from the potential impacts to public safety and harm to the environment from gas migration or from polluting water resources that may result without these additional precautions. As new areas of the Commonwealth are developed for natural gas, these proposed regulations will avoid many potential health, safety and environmental issues.

Compliance Costs

This rulemaking will impose minimal additional cost on the Department. This proposal will help the Department offset potential health, safety and environmental issues.

The Department finds that most gas migration issues stem from inadequate cementing procedures, cement returns, or combinations of inadequate casing and cementing or over-pressured casing seats. Because many of the Marcellus Shall well operators meet or exceed the current well casing and cementing regulations, any increased cost associated with drilling and operating oil and gas wells will be minimal. All of the potential increases in cost to an operator will be associated with assuring a well is properly completed, operated and plugged.

The potential increase in cost is minor when compared to the overall cost of well construction. Where cement is not returned to the surface or when excessive pressure is placed on the surface casing seat, the revised regulations require the operator to install an additional string of casing. The construction cost for the additional string of casing is about $10,000 per well.

Some commentators questioned the Department's estimate for the additional string of casing, stating that the cost of an additional casing string is much more than $10,000 per well, and is more likely on the order of $300,000 to $500,000 per well, depending on depth and area. The commentators stated that if the additional string of casing is justified from a technical standpoint, then it is the correct course of action. But nowhere do the proposed regulations provide a technical justification for an additional casing string.

The added expense described by the commentators does not apply to situations where cement is not returned to the surface. Where production casing is run and set on a packer or casing is set 50 feet deeper than the surface casing, the Department's estimate is sound. Instead, the scenario described more directly relates to the Board's decision to prohibit operators from comingling fresh groundwater with brine by setting very deep surface casing. By setting deep surface casing, operators avoid using deeper intermediate casing and costly cement and cementing practices.

The proposed casing design advocated by the commentators has resulted in several recent gas migration cases in Pennsylvania. These gas migration cases threaten the lives and safety of the citizens of the Commonwealth. The Board did not consider the expense of an intermediate string of casing when it crafted the regulations because the casing design advocated by the commentator results in an unlawful condition. Prohibiting gas migration is the cornerstone of these regulations and compromising on the issue to save money on a necessary string of casing is not acceptable.

Used casing, welded casing and casing attached to a blow-out preventer must be pressure tested to demonstrate its ability to withstand the highest anticipated working pressures to which the casing will be exposed. If the casing fails this test, the operator must repair of replace the casing and ultimately pass the pressure test. The cost to repair or replace the defective casing is completely outweighed by the environmental damage that would result from a failed string of casing and the fact that the casing would still need to be repaired or replaced.

The typical cost to develop a Marcellus Shale well is around $5,000,000. The additional cost of compliance would only be approximately 0.2% of the overall cost to develop a Marcellus Shale well.

The typical cost to develop a shallow gas well is $250,000 and the typical cost to develop an oil well is $200,000. In either situation, the additional cost of compliance would only be approximately 4% to 5% of the overall cost of the well.

All of the additional measures are proposed to reduce the potential for gas migration. If an operator fails to prevent a pollution event of a water supply, the anticipated cost to permanently replace one private water supply would be approximately $4,000 to drill a new water well or $30,000 to provide and permanently pay for a treatment system.

Compliance Assistance Plan

The Department has worked extensively with representatives from the regulated community and leaders the several trade organizations. The requirements of this regulation are, therefore, well known.

The Department, however, several scheduled training sessions for the regulated community to address the Department's regulatory requirements. The Department will use these training sessions as an opportunity to further education the industry about the new requirements.

Paperwork Requirements

The annual well inspection report, the semi-annual production report mandated by Act 15 for operators of Marcellus Shale wells and the additional information required in the completion report will require submittal of two additional forms and additional information on an existing form. The results of gas migration investigations will also require additional reporting obligations.

H. Pollution Prevention

The Federal Pollution Prevention Act of 1990 established a national policy that promotes pollution prevention as the preferred means for achieving state environmental protection goals. The Department encourages pollution prevention, which is the reduction or elimination of pollution at its source, through the substitution of environmentally friendly materials, more efficient use of raw materials, or the incorporation of energy efficiency strategies. Pollution prevention practices can provide greater environmental protection with greater efficiency because they can result in significant cost savings to facilities that permanently achieve or move beyond compliance. This regulation has incorporated the following pollution prevention provisions and incentives:

This regulation will minimize gas migration and will provide an increased degree of protection for both public and private water supplies by updating material specifications and performance testing as well as adding more specific design, construction, operational an monitoring requirements. The plugging, water supply replacement, and gas migrations reporting regulations have been amended to ensure that public safety and groundwater are protected.

I. Sunset Review

This regulation will be reviewed in accordance with the sunset review schedule published by the Department to determine whether the regulation effectively fulfills the goals for which it was intended.

J. Regulatory Review

Under section 5(a) of the Regulatory Review Act (71 P.S. § 745.5(a)), on June 25, 2010, the Department submitted a copy of the notice of proposed rulemaking, published at 40 *Pa.B.* 3845, to the Independent Regulatory Review Commission (IRRC) and the Chairpersons of the House and Senate Environmental Resources and Energy Committees for review and comment.

Under section 5(c) of the Regulatory Review Act, IRRC and the Committees were provided with copies of the comments received during the public comment period, as well as other documents when requested. In preparing these final form regulations, the Department has considered all comments from IRRC, the Committees and the public.

Under section 5.1(j.2) of the Regulatory Review Act, on ___(blank)___, these final form regulations were deemed approved by the House and Senate Committees. Under section 5.1(e) of the Regulatory Review Act, IRRC met on ____(blank)____ and approved the final form regulations.

K. Findings of the Board

The Board finds that:

(1) Public notice of proposed rulemaking was given under sections 201 and 202 of the act of July 31, 1968 (P.L. 769, No. 240) (45 P.S. §§ 1201 and 1202) and regulations promulgated thereunder at *1 Pennsylvania Code* §§ 7.1 and 7.2.

(2) A public comment period was provided as required by law, and all comments were considered.

(3) These regulations do not enlarge the purpose of the proposal published at 40 *Pa.B.* 3845.

(4) These regulations are necessary and appropriate for administration and enforcement of the authorizing acts identified in Section C of this order.

L. Order of the Board

The Board, acting under the authorizing statutes, orders that:

(1) The regulations of the Department of Environmental Protection, *25 Pennsylvania Code*, Chapter 78 are amended to read as set forth in Annex A.

(2) The Chairperson of the Board shall submit this order and Annex A to the Office of General Counsel and the Office of Attorney General for review and approval as to legality and form, as required by law.

(3) The Chairperson of the Board shall submit this order and Annex A to the Independent Regulatory Review Commission and the Senate and House Environmental Resources and Energy Committees as required by the Regulatory Review Act.

(4) The Chairperson of the Board shall certify this order and Annex A and deposit them with the Legislative Reference Bureau, as required by law.

(5) This order shall take effect immediately upon publication in the *Pennsylvania Bulletin*.

BY:

JOHN HANGER
Chairperson
Environmental Quality Board

WATER USE IN MARCELLUS DEEP SHALE GAS EXPLORATION

FACT SHEET MARCH 2010

How much water is used in Marcellus deep shale gas development?

Water is an essential component of Chesapeake Energy's (Chesapeake) deep shale gas development. Chesapeake uses water for drilling, where a mixture of clay and water is used to carry rock cuttings to the surface, as well as to cool and lubricate the drillbit. Drilling a typical Chesapeake Marcellus deep shale gas well requires approximately 100,000 gallons of water.

Water is also used in hydraulic fracturing, where a mixture of water and sand is injected into the deep shale at a high pressure to create small cracks in the rock and allow gas to freely flow to the surface. Hydraulically fracturing a typical Chesapeake Marcellus horizontal deep shale gas well requires an average of five and a half million gallons per well.

How does Marcellus deep shale gas water use compare to regional uses?

The volume of water necessary to drill and fracture Marcellus deep shale gas wells represents a very small percentage of the total water resources used in the Marcellus geographic region. This region generally includes central and western Pennsylvania, southern New York and northern West Virginia. The total water use in the Marcellus Shale area in 2000 was approximately 3.6 trillion gallons. The natural gas industry is expected to increase the amount used by less than 0.1%, and is well within available resources in the region. Again, this volume is very small in terms of the overall water budget for this region. The largest water users in the Marcellus Shale geographic area are power generation (approximately 72%), industry and mining (approximately 16%), and municipal/public water supply (approximately 12%). Agricultural water use accounts for only one-tenth of one percent in this area (0.10%). Water used in Chesapeake Marcellus deep shale gas differs most notably from all other uses because it is temporary, occurring only once during the drilling and completion phases of each well. Use of this water does not represent a long-term commitment of the resource in the Marcellus Shale geographic area.

How much is 5.6 million gallons?

The 5.6 million gallons of water needed to drill and fracture a Marcellus deep shale gas well is equivalent to the amount of water consumed by:

- **New York City** in **eight minutes**
- A 1,000 megawatt coal-fired **power plant** in **13 hours**
- A **golf course** in **28 days**
- **Nine acres of corn** in a season

While these represent continuing consumption, the water used for a shale gas well is a one-time use.

KEY POINTS

- Water resources are protected through stringent state, regional and local permitting processes.
- Natural gas production uses significantly less water per BTU of energy produced than other fuel sources such as coal, oil or ethanol.
- Water is essential for Marcellus deep shale gas development.
- Marcellus deep shale gas drilling and hydraulic fracturing uses a small amount of water compared to other uses within the geographic area.

How much water is used in Marcellus deep shale gas development compared with other energy sources?

Water and energy are interdependent. Water is essential to energy resource development. Conversely, energy resources are needed for producing, processing, distributing and using water resources. A typical Marcellus deep shale gas well will produce approximately 4.2 Bcf (billion cubic feet) of gas over its lifetime, the amount of water used to produce the gas equates to about 1.3 gallons for every million British thermal unit (MMBTU - one MMBTU equals about a thousand cubic feet of gas). To put this in perspective, this is approximately 15% of the water needed to produce one MMBTU of coal that is ready to burn in a power plant or 0.05% of the water needed to produce the same energy equivalent of ethanol for fuel. The table on the following page compares water use per unit of energy for several energy sources.

Water requirements for various energy resources

Energy Resource	Range of Gallons of Water Used per MMBTU of Energy Produced
Marcellus Shale Natural Gas[1]	1.30 [2]
Coal (no slurry transport) Coal (with slurry transport)	2 – 8 13 – 32
Nuclear (uranium ready to use in a power plant)	8 – 14
Conventional Oil	8 – 20
Synfuel - Coal Gasification	11 – 26
Oil Shale	22 – 56
Tar Sands	27 – 68
Synfuel - Fisher Tropsch (from coal)	41 – 60
Enhanced Oil Recovery (EOR)	21 – 2,500
Biofuels (Irrigated Corn Ethanol, Irrigated Soy Biodiesel)	> 2,500

[1]Source: GWPC Report
[2]The transport of natural gas can add between zero and two gallons per MMBTU.
Other Sources: DOE

Where does the water come from?

Chesapeake utilizes a variety of sources of water in Marcellus deep shale gas exploration. The sources include rivers, creeks and lakes. Chesapeake is also reviewing the use of a variety of other water resources such as discharge water from industrial or city wastewater treatment plants, groundwater and reuse of fracturing water. Chesapeake often works directly with local officials to arrange water purchases from a municipality when drilling inside city limits. Water is typically transported by truck to drilling locations for storage prior to use in tanks or impoundments. Chesapeake also uses temporary pipelines to transport water supplies. Due to the extensive and diverse geographic area overlying the Marcellus Shale, the overall mix of water sources used depends on the region and the availability of sources near drilling sites.

Are water resources protected and regulated?

Regardless of the source, water used in the drilling and fracturing process by Chesapeake is purchased and, if necessary, properly permitted. This permitting ensures that water used for drilling and hydraulic fracturing does not interfere with the available supply for other users. In addition, both Pennsylvania and New York require an impact analysis to ensure that the surface water withdrawals will not harm the watershed or other users. The assessments ensure that our use will not adversely affect stream flow, aquatic life, recreational resources or sensitive environments.

Chesapeake works collaboratively with regional, state and local agencies to ensure that water use for deep shale gas development is consistent with water use plans and does not adversely affect other users.

In the Marcellus Shale area, regional river authorities have jurisdiction in multiple states. The federally established watershed authorities have been created to protect the water quality of the entire river basin and to regulate uses of the water. Additional approvals and permits are required for operations in these river basins. Chesapeake actively works with the Delaware River Basin Commission (DRBC) and the Susquehanna River Basin Commission (SRBC) to obtain water for use in Pennsylvania and New York.

Chesapeake's deep shale gas development, with its comparatively small water use per unit of energy, is consistent with the nation's energy/water strategy by making a positive energy and economic contribution at a relatively low cost to the overall water supply. Chesapeake's deep shale gas has the potential to supply decades of natural gas for the U.S., while using less water than other currently available viable energy sources.

Information Sources

- Argonne National Laboratory
- Delaware River Basin Commission
- Ground Water Protection Council (GWPC)
- Sandia National Laboratory
- Susquehanna River Basin Commission
- U.S. Department of Energy (DOE)
- U.S. Geological Survey

About Chesapeake

Chesapeake Energy Corporation is the second-largest producer of natural gas in the U.S. Headquartered in Oklahoma City, the company's operations are focused on the development of onshore unconventional and conventional natural gas in the U.S. in the Barnett Shale, Haynesville Shale, Fayetteville Shale, Marcellus Shale, Anadarko Basin, Arkoma Basin, Appalachian Basin, Permian Basin, Delaware Basin, South Texas, Texas Gulf Coast and East Texas regions of the United States. If you have questions about water use in deep shale gas exploration or other facets of our operations, visit www.chk.com or email us at marcellusshale@askchesapeake.com.

Department of Environmental Protection
Bureau of Oil and Gas Management
Stray Natural Gas Migration Associated with Oil and Gas Wells

Commercial oil production started in Pennsylvania in 1859 when Colonel Drake drilled the famous Drake well in Titusville. From there, petroleum production expanded further into the Venango, Southern and Bradford oil fields of Venango, Warren, McKean, Clarion, Butler and Armstrong Counties. Eventually, the oil belt extended to the southwest corner of the state in the Washington County area. During this 150-year span, hundreds of thousands of gas and oil wells have been drilled in Pennsylvania.

With the number of gas wells drilled in the Commonwealth since the inception of the industry, the potential exists for natural gas to migrate from the wellbore (via either improperly constructed or old, deteriorated wells) and adversely affect water supplies, as well as accumulate within or adjacent to structures such as residences and businesses. Collectively, this may represent a threat to public health, safety and welfare, and is a potential threat of a fire or explosion. The Department has documented such occurrences and these cases are provided in this document.

It should be noted that the Department also receives complaints of stray gas from other sources such as methane gas due to microbial processes or caused by burial of organic matter, landfills, mining activity, transmission or distribution pipeline, or natural causes. These cases are not included in this paper. The discussion in this paper is limited to gas migration cases associated with oil and natural gas wells (i.e. thermogenic in origin).

The gas migration cases are organized into several categories: new wells, operating or active wells, legacy or abandoned wells, and wells associated with underground storage of natural gas.

New wells involve that initial phase of an oil or gas well when the well is being drilled or re-drilled, completed and put into production. For most wells, well completion involves hydraulic fracturing either immediately after the well is drilled or at a later date.

Operating or production wells include wells that are actively producing. It also includes wells that the operator is not actively producing and that are not plugged.

Legacy or abandoned well incidents are associated with natural gas and oil wells drilled from 1859, when Colonel Drake drilled his first commercial well in Titusville, until the present and there is no responsibility operator for the well. The well may have been abandoned by the operator and not properly plugged or plugged according to the standards or practices that were in place at the time. Some of the wells were constructed under the Oil and Gas Act, which was passed in 1984 when new standards for casing, cementing and plugging wells were established. Many were not.

These cases typically involved gas migration from old wells that were abandoned without proper plugging procedures. Often, these wells are associated with the old oil and gas fields surrounding the greater Pittsburgh area or the Bradford or Venango oil fields.

Underground Storage of Natural Gas includes gas migration problems associated with operating gas storage fields.

INVENTORY OF OIL AND GAS WELL STRAY GAS CASES

NEW WELLS – STRAY GAS MIGRATION CASES

McNett Township, Lycoming County - East Resources – NCRO – July 2009: A natural gas leak from an East Resources Oriskany well was confirmed on July 27, 2009. Methane gas from the well impacted multiple private drinking water wells and two tributaries to Lycoming Creek, forced one resident to evacuate her home, and required the closure of access roads near the well. Company personnel took necessary measures to stop the gas leak at the well and stream and drinking water well conditions improved. The suspected cause of the leak is a casing failure of some sort. East Resources continues to monitor homes and wells in the effected area (approximately 6000 foot + radius) where methane has been documented and reports to the Department weekly. Methane was evident in some wells and the subsurface. One gas extraction system was installed at a residence. The investigation is on-going. The Northcentral Regional office expects to receive a report regarding the incident from East Resources in approximately 30 days.

Dimock Migration, Dimock Twp., Susquehanna County - Cabot Oil and Gas – NCRO - 2009: The Department is actively monitoring domestic water supplies and investigating potential cause(s) of a significant gas migration that has been documented in several homes along Carter Road. Free gas has been encountered in six domestic water supplies and dissolved has been found in several of the wells. The operator has placed pilot water treatment systems on three water supplies. Of particular note is that this area has not experienced previous drilling and recent gas drilling in the vicinity has targeted the Marcellus Shale.

Hedgehog Lane, Foster Twp., McKean County – Schriener Oil and Gas – NWRO – April 2009: The Department is actively investigating the report of fugitive gas in domestic water well. Prior to Departmental involvement, the company drilling gas wells in the area provided a new water well to an affected residence. After stray gas was evident in the water well, apparently the concerned resident approached the company directly, a new water well was provided and the impacted well was plugged with bentonite. Some time later, neighboring water well became impacted with stray gas and the resident contacted the Department. During the investigation**,** four gas wells were discovered over-pressured. Packers were placed in those over-pressured wells and the wells were brought into regulatory compliance. At this time, a response in the affected water well has not been observed. Complaints of water quality degradation and water diminutions are also under investigation in the area.

Little Sandy Creek Migration, McCalmont Twp., Jefferson County – NWRO – April 2008: In April, 2008 the Department was informed of a large fugitive expression in Little Sandy Creek. Subsequent investigation indicated the presence of combustible gas in the basement of a nearby residence. It was determined that the gas was entering the structure through an un-sealed sump opening in the concrete floor of the basement. The sump was vented through the wall and the threat to the home was minimized. During the investigation the Department discovered that two recently drilled gas wells were over-pressured and were producing from different geologic strata. Isotopic analysis indicated that a specific gas well was the probable source of the fugitive gas and measures were undertaken to reduce pressure on the casing seat. After continued monitoring at the residence, it was determined that the amount of gas in the sump was decreasing. The basement sump remains vented and the problem is dissipating.

Kushequa Migration, **Hamlin Twp., McKean County – NWRO – September 2007:** A stray gas migration caused a change in water quality and a minor explosion in a community water well. Combustible gas was also encountered in a few private water wells within the village. The Department investigated the stray gas occurrence in September of 2007 and through an investigation determined that a specific over-pressured gas well was the cause of the migration. Pressure was released from the potentially responsible gas well and a positive change in the impacted water well was rapidly noted. Additional production casing was placed in the suspect well to permanently resolve the problem. The responsible party was recently issued a Consent Order and Civil Assessment which they plan to comply. The Department issued a well plugging contract to plug 15 orphan wells adjacent to the water wells.

Alexander Migration, Hickory, Washington County – SWRO: It appears the operator affected an old abandoned well when completing a new well in the area. Stray gas occurs in the soils and contamination exists in private water supplies. DEP is evaluating several wells in the area. The investigation is ongoing.

Five Mile Run A, Knox Twp., Jefferson County – NWRO – April 2009: The Department was made aware that on April 18, 2009 fugitive gas began escaping from a domestic water well. During the investigation, the Department also encountered combustible gas in neighboring water well. At this time evidence is being gathered and it is likely that the cause of the fugitive gas migration may be linked to a recently drilled neighboring gas well. The Department is also investigating three reports of water quality problems that may be associated with the recent gas well drilling in the area. The fugitive gas in the water well is a recent problem and at this time is not linked to the gas in Five Mile Run that is approximately 2,500 feet away.

Five Mile Run, Knox Twp., Jefferson County – NWRO – 2008: Consistent gas streams have been identified at two locations within Five Mile Run. Isotopic samples were obtained in early 2008 and the analysis indicates that the gas is of thermogenic origin. It is unknown when the gas first appeared in the stream. At the time of sampling, only older historic wells (pre-1920's) were in the vicinity. Presently the area is experiencing an increase in drilling activity. The permitted boundary for the Galbraith Gas Storage Field (operated by National Fuel Gas) is located approximately 4000 feet to the closest stream expression of fugitive gas. The source of the gas at this time is unknown.

Mix Run Migration, Gibson Twp., Cameron County – NWRO – Fall 2007: In the fall of 2007, the Department continued the investigation of fugitive gas reported in the water well of a seasonal residence. The presence of gas in the water well is sporadic with no apparent trends in its occurrence noted. The area has experienced no recent drilling although historic records indicate Oriskany gas was produced in the vicinity. All wells that could be identified and field verified within one mile of the stray gas location are in regulatory compliance. The closest gas well was plugged and a gas well with potentially compromised casing (approximately 3000' away) was repaired. Gas was not present in the water well at the time of the last inspection in May, 2009.

Ohl Complaint, Hebron Twp., Potter County – NWRO – June 2007: The Department responded to a complaint of fugitive gas in a water well that serves a seasonal structure in June, 2007. Isotopic analysis indicated a possible similar thermogenic origin of the gas in the water well to a neighboring gas well. Initial efforts to vent the suspected gas well to atmosphere for an extended time failed to reduce the amount of gas in the neighboring water well. The new well owner placed a down-hole packer and additional production casing in the well. This action did not produce a reduction in the fugitive gas in the water well. The Department continues to investigate the complaint.

Miller Gas Migration, **Liberty Twp, McKean County – NWRO – January 2008:** Departmental personnel responded to a report of fugitive gas in a domestic water well that serves a seasonal residence in January, 2008. Investigation by Departmental field representatives discovered that two recently drilled gas well was over-pressured (exceeding the amount of allowable pressure on the casing seat). The operator Placed packers and additional production casing in the gas well, thereby eliminating pressure on the casing seat. The water well was aggressively pumped and over time the amount of combustible gas in the well bore decreased significantly. The gas well was brought back into production when the amount of gas was below the allowable amount.

Head Drive Migration, Millcreek Twp., Erie County – NWRO – fall 2007. In the fall of 2007, the Department initiated an investigation into the report of fugitive gas in the vicinity of several homes along Walnut Creek. The discovery of fugitive gas in the soil near the residences, forced the Erie County Health Dept. to evacuate the neighborhood. The residents were displaced for at least two months. Through the use of isotopic analysis and with a through investigation performed by the Department's field staff, it was determined that the recently drilled neighboring gas wells were the cause of the migration. Through a Consent Order with the Department, the responsible party plugged two defective gas wells and placed packers in the remaining gas wells. The case is presently in private litigation.

Hughes Migration, **Hamlin Twp., McKean County – NWRO – June 2006:** In June, 2006 the Department responded to two water quality/diminution complaints and determined that a change in water quality was evident. Over-pressured conditions were noted at a recently drilled nearby gas well. The gas well operator drilled new water wells for the impacted residences and gas was encountered during the drilling process. Subsequently, when the operator placed additional production casing in the gas well, the Department noted a marked decrease in the amount of gas in the recently drilled water wells. Over time the problem has diminished.

Foote Rest Camp Ground Migration. Hamlin Twp., McKean County – NWRO – Late 1990s: In the late 1990's, the Department responded to a complaint of gas escaping from an abandoned gas well located in a wooded area near a private campground. During the investigation, it was discovered that an extremely large amount of gas (estimated at more than 100 Mcf/day) was venting from the abandoned gas well. The old well became activated when fracing was completed on a new gas well approximately 4000'away. Installation of production casing placed in the new well prevented additional gas from migrating to the abandoned well and the problem was resolved.

OPERATING WELLS STRAY GAS MIGRATION CASES

Harper Migration, Jefferson County – SWRO and NWRO – March 2004: An operating gas well. House explosion resulted in three fatalities. Origin/mechanism of migration: Operating gas well. Pressurization of the annulus on one or more operating gas well(s) was the mechanism of stray gas migration that caused the explosion. Status: Final agreement pending. . Elements of DEP Compliance Order still outstanding.

Dayton Investigation, Armstrong County – SWRO - March, 2008: Area-wide stray gas migration. Evacuation of one residence. Newly drilled gas well was over-pressured and communicated with an abandoned gas well and other operating gas wells. Corrective action at the well resolved the problem.

Origin/mechanism of migration: Newly drilled gas well. Pressurization of surface casing resulted in migration. Frac communicated with abandoned gas well and other operating gas wells. Status: Resolved.

Tin Town Road Migration, Monroe Twp., Clarion County – NWRO – July 2008: The Department became aware of fugitive gas migration that resulted in the fatality in July of 2008. Apparently, fugitive gas migrated from a very old gas well (drilled early 1900's) through the septic system and entered the bathroom of the residence. It is reported that the explosion resulted when the resident attempted to light a candle in the room. It is possible that gas migrated from the gas well through casing that over time had become compromised. The suspect gas well was vented to atmosphere and the problem dissipated. Presently, the well has been plugged by the operator and the case is in private litigation.

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Toy Migration, Armstrong County – SWRO – October 2007: Explosion at a water well enclosure. Well pump was destroyed and damage to enclosure. No injuries. The source was a nearby operating gas well. The water well has been properly vented and is now back in service. The water well quality was affected during drilling and previously restored by the operator of the gas well. The investigation is ongoing.

Origin/mechanism of migration is a newly drilled gas well. Pressurization of the annulus on a recently drilled well was the mechanism of stray gas migration. Status: Investigation is ongoing.

Wilson Investigation, Armstrong County – SWRO - October, 2007: Explosion inside residence. No injuries or significant damage. Stray gas impacted private water supply well and entered home through conduit for waterline. Origin/mechanism of migration was a newly drilled gas well. Pressurization of the surface casing in newly drilled gas well. Status: Resolved

Montgomery Migration, Hamlin Twp., McKean County – NWRO – July 2007: A domestic water well became impacted by fugitive gas in July, 2007. With Departmental involvement, the operator of nearby gas wells initiated a program of pressure testing suspect wells and it was determined that the casing failed on a specific well. Apparently, without a check valve in the production pipeline, the suspect well was feeding pipeline gas into the gas well. The gas migrated through the compromised well casing and into the local aquifer. The operator plugged the suspect well and problem was resolved.

Alexander Investigation, Washington County – SWRO - September, 2006: Stray gas migration impacting several private water supplies, and surface soils. Frac in recently drilled well communicated with abandoned gas well and migrated to shallow groundwater and surface soils.

Origin/mechanism of migration: Operating gas well. Frac communicated with abandoned gas well. Abandoned gas well is constructed with wooden surface casing. Investigation reveals frac at recently drilled well created pathway to abandoned well and further migration into the shallow groundwater system. Status: Investigation is ongoing.

703 Liberty Street Migration, Warren County – NWRO – January 2005: Gas migrating from an operating gas well resulted in an explosion in the boiler room of the house. There were no injuries. Two nearby wells provided house gas to the residence. The problem well was identified and repaired. The investigation lasted several months.

Chestnut Street migration, Washington County – SWRO - May, 2003: An operating gas well resulted in fire and caused house explosions, with two injuries and an evacuation. Origin/mechanism of migration is an operating gas well had leak in casing. Status: Resolved. Gas well was repaired; outcome of the civil court case is unknown.

Unknown name, Armstrong County – SWRO - ~ 1999: House explosion, resulting in destruction of residence and one fatality. Investigation is not well documented. Origin/mechanism of migration is an operating gas well. Pressurization of casing. Status: Resolved

Vtodian Investigation, Allegheny County – SWRO - January, 1992: House explosion, resulting in destruction of residence, one injury and an area-wide evacuation. Origin/mechanism of migration is an operating gas well. Pressurization of the casing was the mechanism of migration of stray gas that caused the explosion. The well has been repaired. Status: Resolved

LEGACY OR ABANDONED WELL CASES

Hulton Road Migration, Westmoreland County – SWRO - October 2009: This incident was first investigated in August of 2004**.** The stray gas occurs in the soils on private property and in the right of way of Hulton Road. Origin/mechanism of migration is an abandoned gas well. In 2009 the Department issued a contract to plug the suspected well and install venting.. Plugging the well did not alleviate the stray gas. The Department let another contract for an additional $10,500 to vent the stay gas..

128 Lilac Court Migration, Allegheny County – SWRO - June, 2009: The stray gas occurs in the soils in a suburban housing development. Currently, the gas is localized in an area in front of a single residence. Origin/mechanism of migration is an abandoned gas well, location and mechanism of migration unknown. Status: Investigation ongoing.

226 Thompson Run Road Migration, Allegheny County – SWRO - May, 2009: The stray gas occurs in the soils in the vicinity of a residence. The area has had historical stray gas incidents. Venting systems have been installed at several locations in the area. Origin/mechanism of migration: source of gas is an abandoned gas well. Its location is unknown. DEP investigation is ongoing.

Independent Valley News Migration, Allegheny County – SWRO - April, 2009: The stray gas occurs in the soils in front of a business. The gas is being vented with a temporary vent system. Origin/mechanism of migration: source of stray gas is an abandoned gas well. Its location is known. The well has been placed on the list for plugging/venting. Status: DEP contractor to properly vent or plug suspect abandoned gas well.

112 Buss Road Migration, Beaver County – SWRO - March, 2009: The stray gas occurs in the soils on private property. Origin/mechanism of migration: source of gas is an abandoned gas well; its location is known. Status: The leaking gas well is being evaluated for proper venting/plugging.

2526 Wexford Bayne Road Migration, Allegheny County – SWRO - March, 2009: Stray gas in soils and inside home. Origin/mechanism of migration: abandoned gas well; its location is unknown. Natural gas service was terminated at a residence. Status: Resolved. The owner installed a venting/alarm system at his own expense.

Wendt Drive Migration, Allegheny County – SWRO - June, 2009: The stray gas occurs in the soils on private property. Origin/mechanism of migration: source of gas is an abandoned gas well. Its location is unknown. DEP investigation is ongoing.

Charleroi Migration, Washington County – SWRO - March, 2009: Stray gas encountered in soils in close proximity to business. Origin/mechanism of migration is an abandoned gas well. The operator of the well refused to accept responsibility for the problem and take corrective actions. Gas was leaking from the well in the parking lot and was adjacent to the buildings slab foundation. DEP issued a contract to plug the well and initially vented the well until work on plugging the well could begin. Plugging was recently completed. DEP will pursuing cost recovery from the operator.

Tarentum Migration, Allegheny County – SWRO - March, 2005 to October 2009: This incident was initially investigated in March, 2005. Thermogenic source from an unknown location resulted in natural gas service to be terminated by the gas utility 3 years ago at 220 W. 7th Avenue. The DEP plugged one abandoned well. This well plugging did not alleviate the stray gas in the 7th avenue area. There was another plugged well nearby, but did not show any signs of a problem. DEP is conducting follow-up work to the plugging contract to vent the area adjacent to the structure. Origin/mechanism of migration: abandoned gas well, location unknown (contracting is awarded and work is about to begin).

Versailles Migration, Versailles, Allegheny County – SWRO – 2007 through 2008: The natural gas migration problem in Versailles has been ongoing for many years. During the boom period from 1919 through 1921, over 175 wells were drilled in the Borough of Versailles which was part of the McKeesport Gas Field. Some wells produced little or no gas and were abandoned without casing or plugging the boreholes. Other wells produced for a few years and were also abandoned with out plugging the wells. During World War II, the call for scrap steel resulted in the removal of steel casings and wellheads. The abandoned wells were cover over or otherwise abandoned. Over the years many venting systems have been installed by the property owners, borough or by DEP. In 2007 and 2008, the Department let an emergency contract to rehabilitate a well on the Saraka property for to relieve the natural gas pressure in the area. The DOE's National Energy Technology Laboratory (NETL) conducted an extensive study of the area. The original budget for the study was about $1 million dollars. This case is ongoing.

Buckner Migration, Washington County – SWRO - December, 2008: The stray gas occurs in a private water supply well. Origin/mechanism of migration source of gas is an abandoned gas well. Its location is unknown. DEP is conducting an ongoing investigation. The water well has been properly vented. Stray gas was migrating into a residence. DEP discovered pathway into home. Gas appears to be migrating through an abandoned coal mine. Status Immediate danger resolved. Investigation as to specific source is ongoing.

2228 Private Drive Migration, Fayette County – SWRO - October, 2008: Stray gas in soils. Origin/mechanism of migration is an abandoned gas well. Its location is unknown. Status: Resolved. This case was resolved by venting gas away from the structure.

630 Tara Court Migration, Ross Township, Allegheny County – SWRO - September 2008: The source of gas is an abandoned gas well, probably located under the parking lot of the Ross Park Mall. Gas service was terminated at the house at 630 Tara Court in the adjacent subdivision. The Mall was contacted and they are to provide maps of the parking lot to help locate the abandoned wells. The stray gas problem at Tara Court was resolved by installing a venting system until the abandoned wells under the parking lot can be located. The case is ongoing.

Pottle Migration, Allegheny County – SWRO - October, 2007: Stray gas discovered in soils at location for new commercial building. Origin/mechanism of migration is an abandoned gas well. Its location is unknown. Status: Resolved. The owners of a commercial building installed a mitigation/alarm system at their expense to resolve the problem.

1100 McCartney Avenue Migration, Allegheny County – SWRO - February, 2007: Stray gas along front of commercial business. The source of gas is an abandoned gas well; its location is unknown. The owner of the commercial building installed a mitigation/alarm system at his expense. Natural Gas service restored.

Sturgeon Migration, Allegheny County – SWRO - September, 2005: Stray gas in close proximity to several residences. Natural gas service terminated. Origin/mechanism of migration is an abandoned gas well. Its location is unknown. DEP installed a venting system to mitigate the gas migration problem at two residences. Status: Resolved. Gas service restored and the occupants returned to their residence. DEP investigated a well between the two properties; however, it was determined during preparations to plug the well that it was an old water well and not the source of gas.

Childers Migration, Washington County – SWRO - June, 2005: Stray gas has impacted soils area wide on private property. The source of gas is an abandoned gas well; its location is known. A gas well was leaking at the surface. There is a dispute of ownership with the well. The Department suspects the integrity of the well may have been affected by deep mining as the stray gas occurrence coincides with documented mine subsidence in the area.

Origin/mechanism of migration: abandoned gas well. Suspected casing/cement failure possible caused by mine subsidence. Status: Investigation Ongoing

Mediate Migration, Westmoreland County – SWRO - November, 2003: The stray gas was impacting private residence. Origin/mechanism of migration: source of gas is an abandoned gas well; its location is unknown. Natural gas service to a structure was terminated. Status: DEP funded mitigation system installed. Structure is protected. Natural gas service restored.

Tanoma Migration, Indiana County – SWRO - July, 2001: The stray gas occurs throughout the soils on private property. Origin/mechanism of migration: The origin of the stray gas is likely coalbed/gas well mixture. The situation was resolved through venting. The specific sources have not identified. Status: Resolved

McDonald Sr. Care Home Migration, Washington County – SWRO - November 2002: Stray gas found inside a Senior Care home, resulted in temporary evacuation. Origin/mechanism of migration is an abandoned gas well. Its location is unknown. The home was evacuated. The problem was resolved by installation of a mitigation system.

Paiano Migration, Armstrong County, -SWRO - September, 2002: Stray gas inside private water supply well resulted explosion in well enclosure. No injuries. Well was properly vented. Origin/mechanism of migration is an abandoned gas well, location unknown. Status: Resolved. Water well properly vented. Well not found.

Bagdad Road Migration, Waterford Twp., Erie County – NWRO – July 2008:
The Department is in the process of investigating a complaint of fugitive gas in a domestic water well received in July of 2008. All area gas wells are in regulatory compliance and isotopic analysis does not indicate a specific source of the stray thermogenic gas.

Clarington Migration, Barnett Twp., Clarion County - NWRO
The Department has been aware of a soil gas seep in a remote area since at least 1987. The source of the gas is unknown, no active gas wells are in the vicinity and a search of historical records failed to indicate any record of oil and gas drilling. The site near Cherry Run has become a seasonal camping spot and the surface expression of the stray gas migration has been improved with stone fire-ring to serve as a campfire location.

Groshek Migration, Keating Twp., McKean County – NWRO – 2008. In 2008 the Department responded to a complaint of stray gas in a domestic water supply. The area of the complaint is in an old oil and gas field that was drilled near the turn of the 20th century. Historic maps were used to attempt to locate nearby abandoned wells. Without any new drilling activity vicinity, the Department plugged four abandoned wells. These efforts of find and fix the cause of the migration have been unsuccessful. A recently discovered gas well has been identified in the field and the well was placed on the department's plugging list.

Leichtenberger Migration, Howe Twp., Forest County - NWRO
In June 2005 stray gas was reported to have entered two springs that serve as domestic water supplies. Located in an area that experienced a long history of oil and gas drilling activity, it was discovered that the migration began near the same time that two gas wells, located more that 3000' away, were fraced. The new gas wells are in regulatory

compliance and additional measures were taken to prevent a gas migration. The department has plugged three abandoned gas wells in the vicinity. All efforts to identify the cause of the migration have been unsuccessful.

Nicholls Migration, Rome Twp., Bradford County – NCRO – June 2007: Complaint received by the Department in June, 2007 of stray gas in a domestic water supply. Isotopic analysis of the gas indicates that it is of thermogenic origin although it apparently does not match any production gas in nearby gas wells.

Skinner Migration, Columbus Twp., Warren County - NWRO
The Department responded to a complaint of stray gas in a domestic water well in June, 2005. All wells within 6000' were inspected and found to be in regulatory compliance except two gas wells. Those two wells were brought into compliance with the addition of production casing. The water supply improved however small amounts of fugitive gas remain in the water well. An abandoned well discovered by the department during the investigation remains on the State's plugging list.

Wayland Road Gas Migration, East Mead Twp., Crawford County – NWRO – October 2008: The Department continues to investigate a fugitive gas migration expressed in a domestic water well first reported in October, 2008. No difficulties were reported by the drilling company during construction of nearby gas wells, all gas wells are in regulatory compliance and it is difficult to determine when the problem became apparent. Isotopic analysis indicates that the fugitive gas is thermogenic in origin although a match to a nearby gas well is not apparent.

Hetrick Gas Migration, Redbank Twp., Clarion County – NWRO – Spring 2007: In the spring of 2007 the Department initiated an investigation into the conditions surrounding the report of fugitive gas in a domestic water well. Isotopic analysis of the stray gas indicates a thermogenic origin potentially similar to neighboring gas wells. A legally defensible case against a potentially responsible party could not be demonstrated and the Department eventually provided the resident with an alternative source of water.

Julie Anne Lane, Summit Twp., Erie County – August 2008: In August of 2008 the Department responded to a report of fugitive gas near a private residence. During the investigation a nearby "plugged" National Fuel Gas well was leaking a very small amount of gas. Isotopic analysis of soil gas samples obtained by the DEP indicated that the gas was probably of microbial origin and fuel gas was restored to the residence.

Mainesburg Migration, Sullivan Twp., Tioga County – NWRO – 2004: The Department became involved with this larger scale stray gas migration in 2004. Elevated levels of fugitive gas were identified in approximately 15 residences. Through a joint action between the department and Township officials, and with funding through a Growing Greener Grant, treatment systems were placed on those affected water wells. Three abandoned gas wells were plugged by the Department.

McCommons Migration, Leidy Twp., Clinton County – NWRO – November 1998: In November 1998 the Department responded to a complaint of stray gas in three water supply wells. Through the course of the investigation it was discovered that because one of the affected water wells was located in the basement of a church, combustible gas migrated from the well and into the indoor air of the structure, causing a significant risk of explosion. Also discovered was that during a recent resurfacing project on Rt. 144, Penndot paved over an abandoned gas well. The Department proceeded to remove the recent pavement and plug the abandoned well. Two of the three impacted water wells returned to normal and a marked improvement in conditions were noted in the third water well.

Mt. Jewett Municipal Well-field Migration, Hamlin Township, McKean County: Three water wells for the municipality of Mt. Jewett were temporarily affected by a stray gas occurrence in 2008. The migration lasted approximately one week and went away for no apparent reason. After the event, the department plugged a nearby abandoned gas well.

Sara Coyne, City of Erie, Erie County – NWRO – April 2008: In April of 2008, the department responded to a complaint of gas bubbling in a large body of standing water in a campground near the entrance to Presque Isle State Park. Soil gas samples obtained for isotopic analysis indicated that the composition of the gas is consistent with shallow shale gas of the area. Excavation done by the property owner encountered an abandoned gas well approximately 6 feet below ground surface. The gas well was subsequently plugged.

Environmental Air Migration, Pittsburgh, Allegheny County
The source of gas is an abandoned gas well; its location is unknown. Natural gas service was restored following installation of a mitigation system.

Owens Migration, Allegheny County
The source of gas is an abandoned gas well; its location is known. A site developer disturbed the well and was required to properly abandon the well.

Marshall Avenue Migration, Chartiers, Washington County

The source of gas is a possible coalbed/gas well mixture. The area has been properly vented. DEP suspects a gas well was leaking into a mine void.

Elliot Migration, Armstrong County
The source of gas is an abandoned gas well; its location is unknown. The case was resolved by properly venting a water well.

UNDERGROUND STORAGE OF NATURAL GAS CASES

Tioga Junction Migration, Tioga Twp., Tioga County – NWRO - 2008: In January 2001, the Department responded to a report of gas in the soil near two buildings. Further investigation indicated the presence of a potentially widespread stray gas migration problem. In 2008, Dominion Transmission and PPL Gas Utilities Corp. initiate a voluntary program to ensure safe source of drinking water for residences near Tioga Storage Field. 288 letters were sent of area homeowners requesting the opportunity to sample individual water supplies. A large number of residents responded and the extent of the potential stray gas by sampling was delineated. Water treatment systems were provided, at no cost to the homeowner, to those water supplies that were shown to have been impacted. The companies and the Department remain in the investigation process.

Sabinsville Migration, Borough of Sabinsville, Tioga County – NWRO – 2005 ongoing: The Department is aware of a fugitive gas migration in the water supplies for several residences in Sabinsville. Initial sampling occurred in 2005 and elevated levels of methane/ethane were encountered. The homes are located within the footprint for the Sabinsville Gas Storage Field that is operated by Dominion Transmission Inc. Isotopic samples have been obtained from the affected water wells and gas wells within the storage field. The cause of the migration has not been determined.

News Release

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DEP Issues Report on Short-Term Air Quality Impacts from Marcellus Shale Operations in Southwest PA
Agency Continues to Monitor Air Quality in Other PA Regions

HARRISBURG -- Department of Environmental Protection today released a report on a five-week air quality study conducted near Marcellus Shale natural gas operations in southwestern Pennsylvania's Greene and Washington counties.

"This short-term study only provides a snapshot of the air contaminants we found at surveyed sites, but the data shows no emission levels that would constitute a concern to the health of residents living near these operations," DEP Secretary John Hanger said, noting that the report does not assess the potential cumulative effects from natural gas operations.

"These results only provide preliminary information about the type of pollutants released to the atmosphere. Drilling activity continues to increase at a rapid pace across the state, so this study provides us with good information as part of our ongoing effort to gauge the impact these operations have on our air quality, public health and the environment. Needless to say, we plan to conduct more of these types of air-sampling exercises moving forward," Hanger added.

DEP's assessment focused on concentrations of volatile organic compounds, including benzene, toluene and xylene, which are typically found in petroleum products. The department also sampled for other pollutants including carbon monoxide and nitrogen dioxide near natural gas extraction and processing sites.

The agency gathered samples to provide background data at its monitoring station in Florence, a section of Hanover Township, Washington County.

The air monitoring surveys near natural gas operations were conducted at a wastewater impoundment, tank farm and two compressor stations. Those surveys detected the main constituents of natural gas—including methane, ethane, propane and butane—as well as low levels of associated compounds, including benzene and n-hexane, which were detected infrequently at the tank farm and at a compressor station. Higher concentrations of the main constituents of natural gas were detected mainly near the compressor stations.

Methyl mercaptan, a gas which has a penetrating and unpleasant odor similar to rotten cabbage or rotten eggs, was also detected at concentrations that generally produce odors at each location where samples were taken. That threshold is about one part per billion.

The air sampling surveys conducted for carbon monoxide, nitrogen dioxide and ozone precursor emissions did not detect levels above national ambient air quality standards at any of the surveyed sites. However, DEP has not yet determined if the potential cumulative emissions of these air contaminants will cause or contribute to violations of the national ambient air quality standards.

DEP is conducting similar air monitoring studies near Marcellus gas facilities in the Dimock area of Susquehanna County, as well as in the north-central region of the state, to determine if there is a consistent statewide emissions profile for air contaminants near natural gas operations. All studies are expected to be complete in January 2011.

Since 2005, 2,300 Marcellus Shale wells have been drilled in Pennsylvania.

To view the report, visit **www.depweb.state.pa.us** and click on "Regional Resources," then on "Southwest Region" and choose the "Community Information" link on the right side of the page.

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