Richard L. Atkinson
221 Deer Lane
DuBois, PA 15801
814-583-7926
Marianne5@windstream.net

RE: Windfall Oil & Gas, Inc.
Permit # PAS2D020BCLE
PERMITTED FACILITY: Class II-D injection well, Zelman #1

RECEIVED
U.S.E.P.A.
2014 NOV 28 PM 1:10
ENVIR. APPEALS BOARD

Clerk of the Board
U.S. Environmental Protection Agency
Environmental Appeals Board
1200 Pennsylvania Avenue, NW
Mail Code 1103M
Washington, DC 20460-0001

November 24, 2014

Dear Clerk Durr,

I am submitting this petition for review of UIC Permit # PAS2D020BCLE for Windfall Oil & Gas to construct and operate the Zelman #1 Class II Disposal Injection well.

This petition for review of UIC Permit # PAS2D020BCLE complies with word limitations. I did participate in the public hearing and the two public comment periods regarding this matter.

Sincerely,

Richard L. Atkinson

Richard L. Atkinson

BEFORE THE ENVIRONMENTAL APPEALS BOARD
UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
WASHINGTON, D.C.

RECEIVED
U.S.E.P.A.
2014 NOV 28 PM 1:10
ENVIR. APPEALS BOARD

In re:	)
	)
	)
Windfall Oil and Gas	)
UIC Permit No. PAS2D020BCLE	)
Zelman #1 Class II-D injection well	)
	)

PETITION FOR REVIEW

PETITIONER
Richard L. Atkinson
221 Deer Lane
DuBois, PA 15801
814-583-7926
Marianne5@windstream.net

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Passim – 25 PA CODE 78.73(c)

End - Certificate of Service

Overpressuring the Long String Casing Annulus

The Windfall Oil & Gas UIC Permit # PAS2D020BCLE should be remanded until the following questions are answered:

1. Does PADEP regulation 25 Pa Code 78.73(c) require the operator to control any *liquid* pressure at the bottom of the 1000 foot surface casing in the open annulus between the surface casing and the long string casing? The regulation seems to require that only the *gas* pressure in the annulus is to be limited to less than 80% of the calculated pore pressure at 1000 feet (346 psi).

2. Is it possible to install a liquid pressure measuring device in the annulus to determine the liquid pressure at 1000 feet?

3. Should there be an automatic shutdown feature incorporated into the well design to stop the injection of waste fluid if the pressure at the bottom of the surface casing exceeds the pore pressure at 1000 feet (346 psi)?

4. Should the cement sheath at the bottom of the long string casing be extended above the 5000 foot level? A recent NETL report concluded that the Tully Limestone is not always a reliable fracture barrier for horizontal Marcellus gas wells.

5. Should there be an intermediate casing installed so that the long string casing can have a cement seal the whole way up to the surface casing?

6. Should there be a means to pump liquid out of the open annulus between the surface casing and the long string casing above 1000 feet?

The requirements for constructing the Windfall disposal injection well allow for an open annulus between the wellbore and the 4 ½" diameter long string casing. The open annulus begins at the top of the cement sheath around the long string casing, at 5000 feet deep, and extends upward to the bottom of the cement sheath around the surface casing, at 1000 feet deep, and then up through the inside of the surface casing to ground level.

In addition, the permit allows the fracturing of any confining zone that is below the confining zone adjacent to the lowermost USDW. The permit only prohibits fracturing of the confining zone adjacent to the lowermost USDW. Fracturing is permitted at levels farther down. Therefore, Marcellus gas wells are allowed to be constructed in the Area of Review.

The permit mentions no provision for venting the open annulus or capturing any fluid that may flow out of the open annulus at the wellhead. Allowing pressure buildup caused by closing off the annulus would be very risky.

The permit for the Windfall disposal well has evolved from originally designating the confining zone to be adjacent to the top of the injection zone. The latest version of the permit designates the confining zone to be below and adjacent to the lowermost USDW as the only zone that is not allowed to be fractured.

A study done in March 1985 by Samuel S. Harrison, titled "Contamination of Aquifers by Overpressuring the Annulus of Oil and Gas Wells", explains the situation of an open annulus for Medina gas wells in northwestern PA.

The principles discussed in the above study also apply to the Windfall disposal injection well. The overpressuring of the annulus problem for the Windfall disposal injection well is even more serious. The pressure at the bottom of the injection well is allowed to be 6425 psi, which is about double the natural formation pressure. The permit places no prohibition on drilling Marcellus gas wells in the Area of Review. The fracturing of these Marcellus gas wells increases the possibility of injected waste migrating into the open annulus of the disposal well itself.

An Evaluation of Fracture Growth and Gas/Fluid Migration as Horizontal Marcellus Shale Gas Wells are Hydraulically Fractured in Greene County, Pennsylvania

15 September 2014

U.S. DEPARTMENT OF ENERGY

Office of Fossil Energy

NETL-TRS-3-2014

On page 1 of the report above, an important result is presented. When a horizontal Marcellus well was fractured, the data collected showed that about 40% of about 10,288 microseismic events were recorded above the Tully Limestone. On page 43, the report says these events form clusters 1000 to 1900 feet above the Marcellus well, showing that the Tully Limestone does not always act as an upper fracture barrier.

In the Response to Comments, #12, page 14, it says that Windfall has proposed a stimulation program for the bottom of the disposal well.

The Windfall stimulation program could possibly result in the injection pressure of 6425 psi to be transmitted radially through the resulting fractures many hundreds of feet from the bottom of the injection tube.

The NETL report on page 9 describes how shallow vertical gas wells that were hydraulically fractured and had 750 foot radial fracture growth. This amount of fracturing increases the chance that the disposal injection well will communicate with one or more Marcellus wells that are permitted to be constructed later on. If the highly pressurized waste fluid gets into the Marcellus well fractures, it may be provided with a pathway to the open annulus of the injection well.

The open annulus has a volume that is most likely less than 600 barrels. The pressure required to lift waste fluid with a specific gravity of 1.26 from the top of the long string casing cement, at 5000 feet, to surface level is 2730 psi. This is less than half of the maximum allowable injection pressure of 6425 psi.

Suppose that 1% of the injected waste fluid is able to leak into the open annulus at a reduced pressure that exceeds 2730 psi. The limit on the rate of disposal is 30,000 barrels per month. In 2 months the annulus could be filled.

The open annulus outside of the long string casing penetrates the ultimate confining zone adjacent to the lowermost USDW, which is at about 800 feet deep. Below 1000 feet, the annulus is exposed to the bare rock layers of the wellbore. Above 1000 feet, the annulus is sealed from the rock of the wellbore by a surface casing with a cement sheath.

The open annulus of any well poses a threat to the USDW's. Higher pressure gas from exposed lower rock formations containing hydrocarbons can move up through the open annulus into drinking water aquifers in the upper rock layers that are not protected by the surface casing. This contamination occurs if the annular pressure exceeds the pore pressure.

In an attempt to avoid the above from occurring, the PADEP regulations (25 PA Code 78.73(c)) limit the gas pressure in the annulus to 80% of .433 psi/ft multiplied by the length of the surface casing in feet. The pressure gradient of fresh water is .433 psi/ft.

Therefore, the regulation requires the operator to limit the pressure in the annulus to 80% of the theoretical pore pressure at the bottom of the surface casing. In the case of the Windfall disposal well this pressure limit is 346 psi.

If the open annulus above the bottom of the surface casing were to contain liquid, the situation is more complicated. The pressure at the bottom of the surface casing would be the sum of the gas pressure plus the pressure resulting from the weight of the liquid.

The additional liquid pressure can be determined by multiplying the pressure gradient of the liquid times the height of the liquid surface above the base of the surface casing. The pressure gradient of the liquid is its specific gravity times the pressure gradient of freshwater (.433 psi/ft).

- The injected waste fluid is allowed to have a maximum specific gravity of 1.26. The pressure gradient of the waste fluid is therefore .546 psi/ft. A column of waste fluid produces 26% more pressure at any level than freshwater.

Suppose the open annulus inside the surface casing does contain both gas and liquid wastewater. The question of whether the confining zone can be fractured if a pressure gauge at the surface reads only 346 psi is investigated below.

In drilling publications and in the Response to Comments, values are given for fracture pressure gradient from .7 psi/ft to .950 psi/ft. The fracture pressure at the bottom of the surface casing can be estimated to be between 700 psi and 950 psi depending on the value of fracture gradient chosen.

If the 950 psi/ft fracture pressure is assumed to be accurate, the bare wellbore at 1000 ft deep could tolerate a column of waste fluid 1106 feet high with an enclosed gas pocket above it at 346 psi before the sum of these two pressure sources exceed the fracture pressure of 950 psi.

If the lower value of 700 psi is more realistic, then the situation is more risky. A column of waste fluid only 648 feet high with a pocket of gas at 346 psi above it would fracture the confining zone.

If the total pressure of a combination of waste fluid and natural gas in the annular space is to be held below 346 psi at the 1000 foot depth, in order to have it below 80% of the pore pressure at a depth of 1000 feet, then the contamination of a USDW is even more unlikely. A pressure limit of 346 psi would be more in line with the purpose of 25 PA Code 78.73(c)). A height of wastewater 633 feet above the bottom of the surface casing, with zero gas pressure above, is all that is needed to reach 346 psi.

If a measurement of the liquid pressure at 1000 feet could be obtained, the empty annulus would be transformed from a threat to local USDW's to a valuable means of monitoring and controlling the disposal well.

A method of measuring the liquid pressure at 1000 feet would be to hang a tube at least 1000 feet long down the open annulus of the disposal injection well. The end of the tube in the annulus would be open. The surface end would be connected to a low flow natural gas supply capable of providing at least 346 psi of pressure. The gas pressure at the top end of the tube would correspond to the pressure at the open end at 1000 feet deep at the bottom of the surface casing.

There is a simple electrical means of measuring liquid level in a well. Corrosion problems may make electrical methods unreliable over a long period of time.

- The NETL report, cited previously, states that the Marcellus well hydraulic fractures could possibly extend approximately 2000 feet above the Onondaga Limestone. Since the Onondaga Limestone is at 7000 feet deep, the extent of the Marcellus well fractures could be precariously close to the 5000 foot level of the top of the long string casing cement. Above 5000 feet, the annulus above the long string casing and the wellbore is open. Although there would be additional cost, it may be prudent to extend the cement up another 1000 feet or more above the 5000 foot depth that is required by the permit.

CONCLUSIONS

The Windfall UIC permit # PAS2D020BCLE for the disposal injection well should be remanded. The problem of being able to monitor the liquid pressure in the open annulus between the surface casing and the long string casing should be studied. A method to continuously measure this pressure should be found.

If there is no requirement for an automatic system on the well to shut off the injection pump if a predetermined pressure limit is exceeded in the open annulus at the bottom of the surface casing, the permit should be denied.

The permit should be remanded to study the cementing plan for the long string casing. If the long string casing cement is not required to be extended up to 4000 feet below surface level or higher, the permit should be denied.

The permit should be remanded and the need for a provision to pump liquid out of the open annulus should be studied. If no system to remove liquid from the open annulus is required, the permit should be denied.

Date: November 24, 2014

Respectfully submitted by,

Richard L. Atkinson

Richard L. Atkinson

Attachment "M"
Construction Details –subsurface
Zelman#1 Injection Well

EXHIBIT A

ZELMAN WELLBORE SCHEMATIC

Elevation 1697'

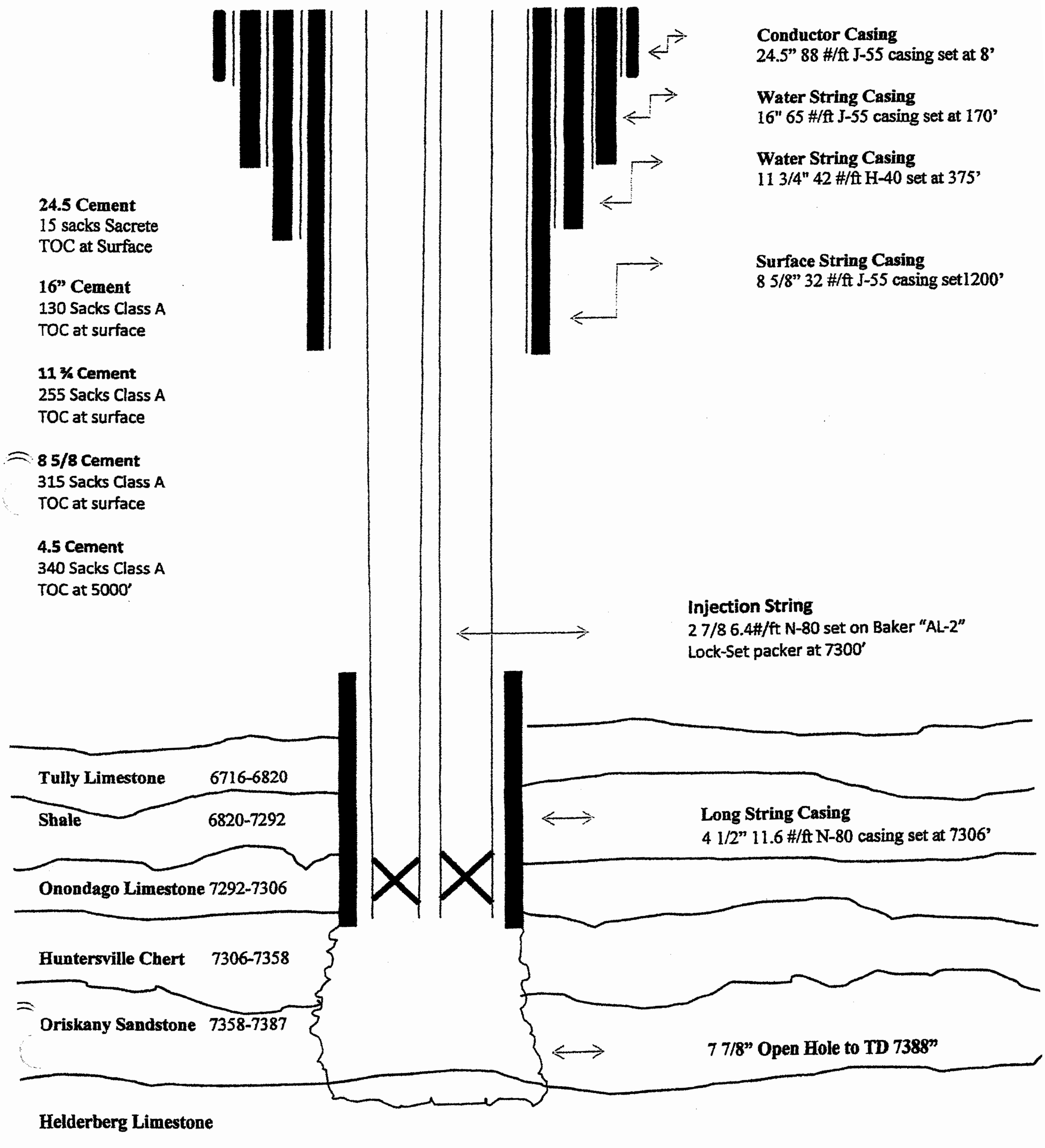


EXHIBIT B

Attachment "M"
Construction Details –subsurface
Zelman#1 Injection Well

ZELMAN WELLBORE SCHEMATIC (MODIFIED BY RLA)

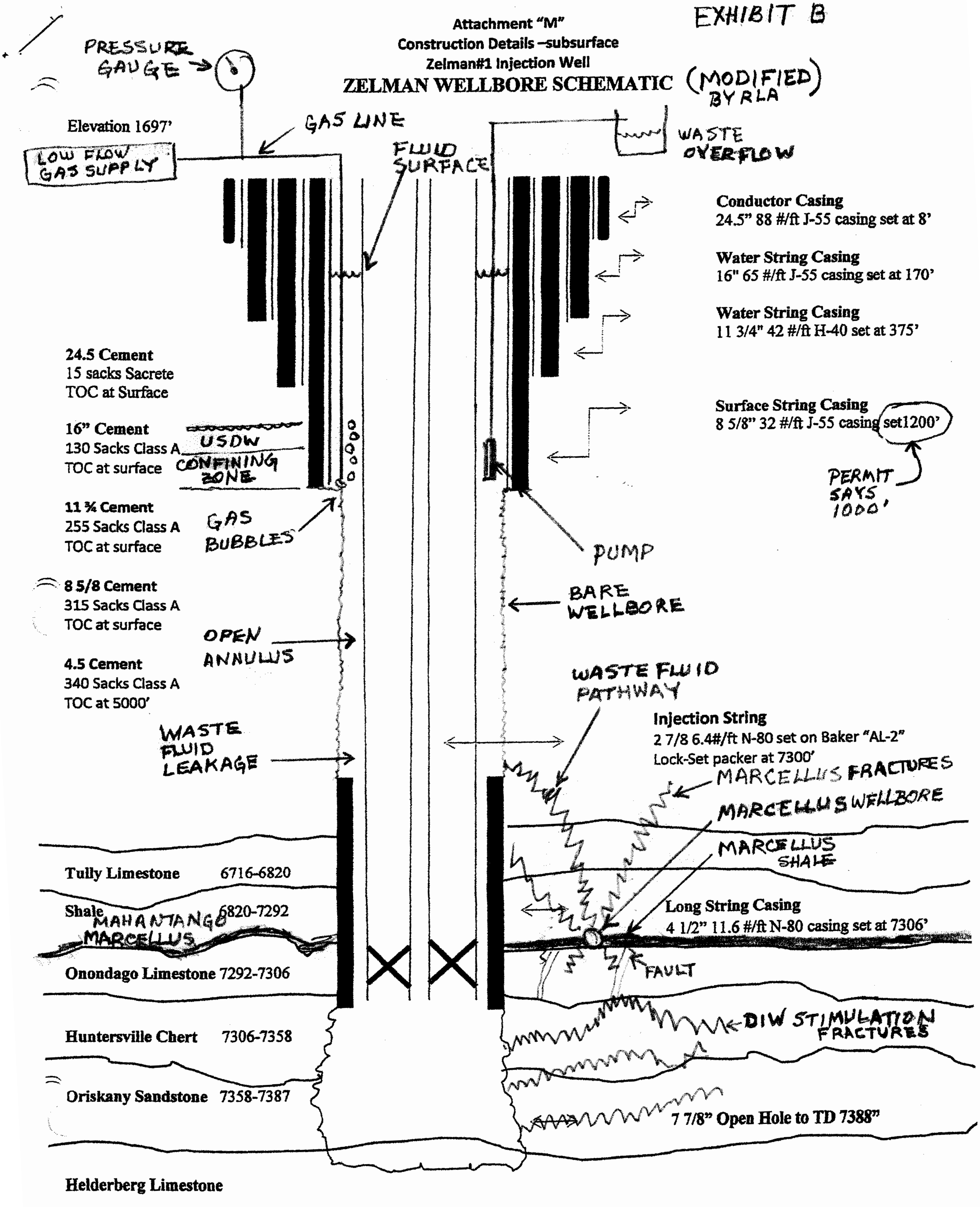


EXHIBIT C

§ 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.

(b) The operator shall prevent gas, 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.

(c) After a well has been completed, recompleted, reconditioned or altered the operator shall prevent surface shut-in pressure and surface producing back pressure inside the surface casing or coal protective casing from exceeding the following pressure: 80% multiplied by 0.433 psi per foot multiplied by the casing length (in feet) of the applicable casing.

(d) After a well has been completed, recompleted, reconditioned or altered, if the surface shut-in pressure or surface producing back pressure exceeds the pressure as calculated in subsection (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.

EXHIBIT D

EXECUTIVE SUMMARY

This field study monitored the induced fracturing of six horizontal Marcellus Shale gas wells in Greene County, Pennsylvania. The study had two research objectives: 1) to determine the maximum height of fractures created by hydraulic fracturing at this location; and 2) to determine if natural gas or fluids from the hydraulically fractured Marcellus Shale had migrated 3,800 ft upward to an overlying Upper Devonian/Lower Mississippian gas field during or after hydraulic fracturing.

The Tully Limestone occurs about 280 ft above the Marcellus Shale at this location and is considered to be a barrier to upward fracture growth when intact. Microseismic monitoring using vertical geophone arrays located 10,288 microseismic events during hydraulic fracturing; about 40% of the events were above the Tully Limestone, but all events were at least 2,000 ft below producing zones in the overlying Upper Devonian/Lower Mississippian gas field, and more than 5,000 ft below drinking water aquifers.

Monitoring for evidence of fluid and gas migration was performed during and after the hydraulic fracturing of six horizontal Marcellus Shale gas wells. This monitoring program included: 1) gas pressure and production histories of three Upper Devonian/Lower Mississippian wells; 2) chemical and isotopic analysis of the gas produced from seven Upper Devonian/Lower Mississippian wells; 3) chemical and isotopic analysis of water produced from five Upper Devonian/Lower Mississippian wells; and 4) monitoring for perfluorocarbon tracers in gas produced from two Upper Devonian/Lower Mississippian wells.

Gas production and pressure histories from three Upper Devonian/Lower Mississippian gas wells that directly overlie stimulated, horizontal Marcellus Shale gas wells recorded no production or pressure increase in the 12-month period after hydraulic fracturing. An increase would imply communication with the over-pressured Marcellus Formation below.

Sampling to detect possible migration of fluid and gas from the underlying hydraulically fractured Marcellus Shale gas wells commenced 2 months prior to hydraulic fracturing to establish background conditions. Analyses have been completed for gas samples collected up to 8 months after hydraulic fracturing and for produced water samples collected up to 5 months after hydraulic fracturing. Samples of gas and produced water continue to be collected monthly (produced water) and bimonthly (gas) from seven Upper Devonian/Lower Mississippian gas wells.

Current findings are: 1) no evidence of gas migration from the Marcellus Shale; and 2) no evidence of brine migration from the Marcellus Shale.

Four perfluorocarbon tracers were injected with hydraulic fracturing fluids into 10 stages of a 14-stage, horizontal Marcellus Shale gas well during stimulation. Gas samples collected from two Upper Devonian/Lower Mississippian wells that directly overlie the tracer injection well were analyzed for presence of the tracer. No tracer was found in 17 gas samples taken from each of the two wells during the 2-month period after completion of the hydraulic fracturing.

EXHIBIT E

Wells A and B were hydraulically fractured on April 24–29, 2012; only the first stage (toe stage) of Well C was completed at this time. Stages 2–10 of Well C were hydraulically fractured on May 2–6, 2012. Wells D, E, and F (that extend southeastward) were hydraulically fractured on June 4–11, 2012. A total of 65 stages were treated using conventional plugging and perforation through cemented casing. A "zipper-type" sequencing of treatment stages was used for Wells A and B, and then for Wells D, E, and F. Treatment was delayed for Well C, so that well was stimulated separately. Within each stage, perforation clusters were spaced about 110 ft apart with three clusters per stage. Each 2-ft perforation cluster used 0° phasing (all perforations pointed downward) at 5 perforation shots per foot, for a total of 10 shots per cluster. For Wells A, B, C, E, and F, the stage treatment design used "slickwater" (7,530 barrels or bbls), 100-mesh sand from 0.25 pounds per gallon (ppg) to 1.00 ppg, and 40/70-mesh sand from 1.00 ppg to 2.00 ppg (0.25 ppg increments). Total designed sand was 300,000 lbs/stage. For Well D, the treatment design was doubled, using 15,060 bbls of "slickwater" and 600,000 lbs of sand per stage. Chemicals added to fresh and recycled water for hydraulic fracturing included friction reducer, bactericide, scale inhibitor, and gel with breaker (also see Table 6 in Appendix E). The wells were drilled and hydraulically fractured by the operator.

1.1.2.2 Upper Devonian/Lower Mississippian Gas Wells

At the Greene County Site, a producing gas field overlies the horizontal Marcellus Shale wells and was used as the monitoring interval (Monitored Interval, Figure 2) between the hydraulically fractured zone (Fractured Interval, Figure 2) and a near-surface zone containing freshwater aquifers (USDW, Figure 2). Within the monitored interval, natural gas has been produced since 2006 from multiple completions in thin (<10-ft thick) sandstones within a 2,300-ft thick interval of sandstone, siltstone, and shale. The base of the monitored zone is about 3,800 ft above the underlying horizontal Marcellus Shale gas wells while the top of the zone is at least 1,300 ft below the deepest known freshwater aquifer at the site.

Vertical gas wells in the monitored zone were completed in the Squaw Sand of the Mississippian age Shenango Formation and multiple sands within the Upper Devonian age Venango and Bradford Formations (5th, Bayard, Speechley, Balltown, 1st Bradford, and 2nd Bradford sands) (Figures 2 and 6). Within the study area, there are seven vertical wells that were drilled and hydraulically fractured by the operator to produce natural gas from this zone. The vertical wells were drilled on 1,500-ft spacing based on the expectation of at least 750-ft radial fracture growth away from the vertical wells during hydraulic fracturing. Three wells completed in the monitored interval directly overlie horizontal Marcellus Shale gas Wells A and E that were hydraulically fractured (UD-1, UD-2, and UD-5; Figures 7 and 8); four wells (UD-3, UD-4, UD-6, and UD-7; Figure 7) are in offset positions from horizontal Marcellus Shale gas Wells D, E, and F.

EXHIBIT F

3. CONCLUSIONS

The research objective at the Greene County site was to assess the extent and nature of fluid and gas migration from a six-well, hydraulically fractured Marcellus Shale development site. This objective was addressed by examining five independent methods that were available using existing well infrastructure at the site. The methods employed: 1) microseismic monitoring from geophones deployed in vertical Marcellus Shale wells; 2) production and pressure histories from shallower Upper Devonian/Lower Mississippian gas wells; 3) chemistry and isotopic composition of natural gas from Upper Devonian/Lower Mississippian and Marcellus Shale gas wells; 4) chemistry and isotopic composition of produced water from Upper Devonian/Lower Mississippian and Marcellus Shale gas wells; and 5) monitoring of gas produced from Upper Devonian/Lower Mississippian wells for the presence of perfluorocarbon tracers that had been injected with the hydraulic fracturing fluid into a horizontal Marcellus Shale gas well. The five methods were pursued in parallel by five teams that included researchers from government, academia, and industry. The teams included:

1. Microseismic Monitoring – NETL and Weatherford
2. Pressure and Production History – NETL
3. Isotopic Signature of Natural Gas – West Virginia University and Isotech
4. Isotopic Signature of Produced Water – University of Pittsburgh
5. Perfluorocarbon Tracers – NETL, ProTechnics, and SpectraChem

Overall conclusions pertaining to whether fluid and gas has migrated upward from the hydraulically fractured formation to the monitoring zone were made by NETL based on evidence provided by each team.

3.1 MICROSEISMIC MONITORING

Microseismic events observed during hydraulic fracturing at the Greene County site were primarily located in formations below the Tully Limestone for horizontal Marcellus Shale Wells D, E, and F. However, for Wells A, B, and C, microseismic events located above the Tully Limestone formed clusters that were 1,000 to 1,900 ft above the well. The maximum heights of these clusters are consistent with the likely uppermost extent of reverse faults (as mapped by 3-D surface seismic). Because no fault was observed at this specific location, this suggests that pre-existing fractures or small-offset (sub-seismic) faults may have focused the energy of hydraulic fracturing on certain areas and that microseismic event clusters occur where pre-existing faults or fractures terminate below younger, undisturbed strata in the Upper Devonian. Microseismic results suggest that the Tully Limestone did not always act as an upper frac barrier at this site. Above-Tully Limestone events were observed during the hydraulic fracturing of all stages of horizontal Marcellus Shale Wells A and B, and Stage 1 of Well C. For horizontal Marcellus Shale Wells D, E, and F, above-Tully Limestone events were mostly limited to Stages 1, 2, and 3. Although microseismic events were observed higher than would be expected based on the assumption that the Tully Limestone is an upper frac barrier, the uppermost microseismic events were at least 1,800 ft below the lowermost producing zone in the Upper Devonian/Lower

"A GUIDE TO WELL CONSTRUCTION" P.46 GEK ENGINEERING

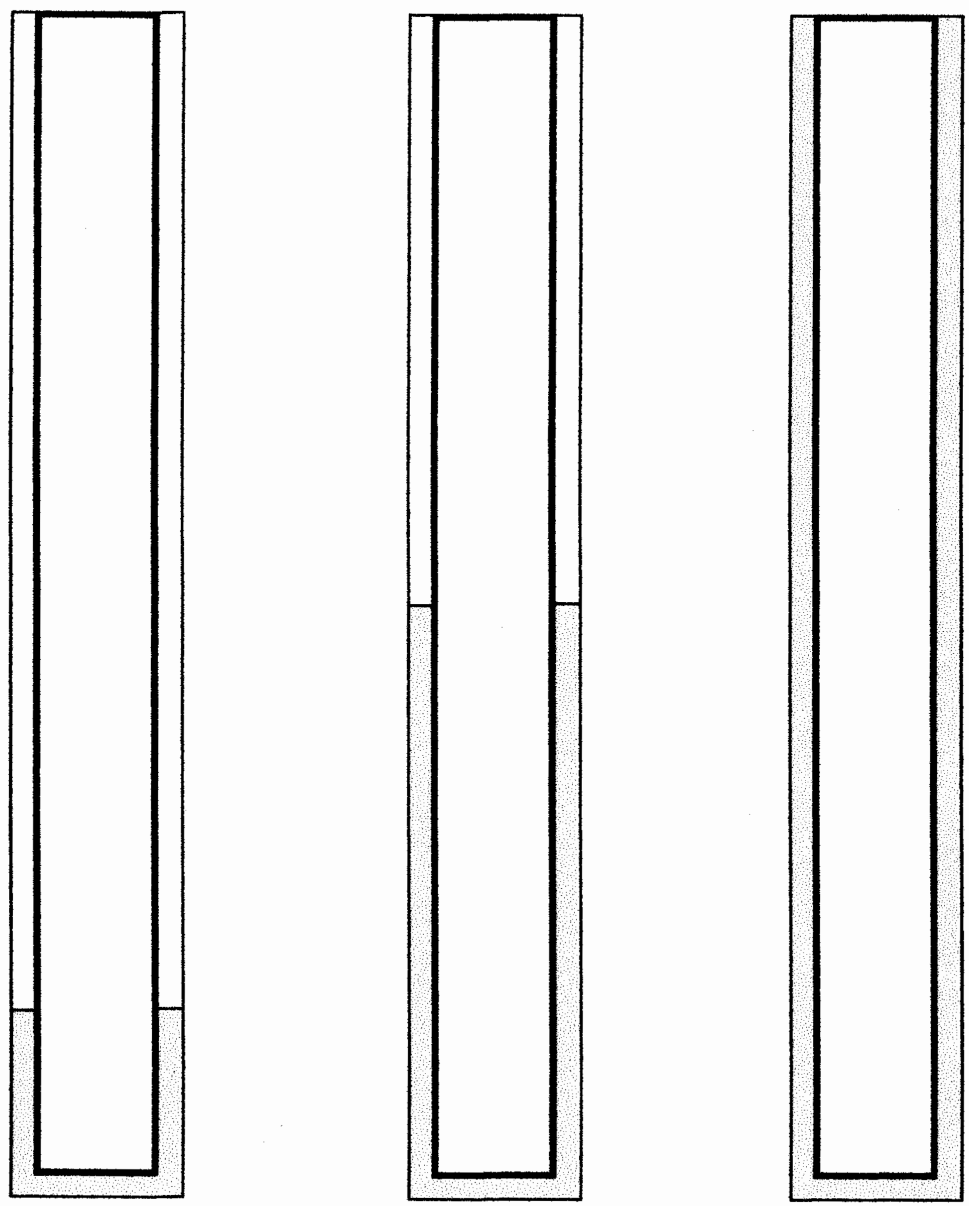
How far is cement brought up the annulus?

EXHIBIT G

Is the cement brought to surface? – Unlikely.

Why?

1. Fracture gradient is usually 0.7 psi/ft, cement density is 0.85 psi/ft.
2. Time
3. Cost
4. Not understanding protection need.



Minimum 200 to 500 ft above the shoe

EXHIBIT G

EXHIBIT H

Contamination of Aquifers by Overpressuring the Annulus of Oil and Gas Wells

by Samuel S. Harrison[a]

ABSTRACT

Medina gas wells and oil wells in northwestern Pennsylvania, northeastern Ohio, and western New York create a potential for contamination of the fresh-water aquifers that overlie the production zones of these wells. Most of these wells are constructed in a manner which results in an open annulus which is a few hundred to a few thousand feet long below the surface casing of the well. This annulus is a potential avenue of migration of contaminants from strata of higher hydrodynamic pressure into formations of lower hydrodynamic pressure. If gas from the strata exposed to the annulus is not permitted to escape to the atmosphere, the annulus may become pressurized, and a hydraulic gradient may be created between the potential contaminants in the annulus (e.g., brine and/or natural gas) and the overlying fresh-water aquifers. If a permeability pathway exists between the pressurized annulus and an overlying fresh-water aquifer, contamination of the aquifer will result.

The risk of contaminating fresh ground water with the contents of a gas- or oil-well annulus could be greatly reduced by filling the annulus with cement. An alternative precaution would be to operate the well in a manner that does not allow the annulus pressure to exceed the normal pressure of the formations exposed to the annulus.

INTRODUCTION

It is common practice when constructing an oil or gas well in the eastern Ohio, northwestern Pennsylvania, and western New York region to install a surface casing. This is done in part to keep fresh water out of the well and to prevent entry of brine, natural gas, and other contents of oil- or gas-well annuli into strata containing fresh water. Because the actual location of the boundary between the zone of fresh-water flow and the underlying saline water is usually not known, the bottom of the deepest fresh-water aquifer (as opposed to aquitard) is often assumed to represent that boundary.

Despite the installation of surface casing, several instances of subsurface entry of contaminants from gas and oil wells into fresh-water aquifers have occurred (Harrison, 1983). In some cases the cause of the contamination is that the completed gas or oil well was operated in a way that caused the pressure in the annulus below the bottom of the surface casing to exceed the normal pressure that existed there prior to drilling the well. This overpressuring of the annulus can cause liquids and/or gas to flow upward into the overlying zone of fresh ground-water flow (Harrison, 1983; Waite and others, 1983). Novak (1984) reviewed ten cases of aquifer contamination by gas- and oil-well operations in northwestern Pennsylvania and found that overpressurization of the well annulus was cited as the cause of contamination in three out of five incidents where the contaminants had been introduced into aquifers from a subsurface source. In one case, natural gas from an overpressured annulus travelled to household-water wells located more than 4000 ft from the gas well.

State regulations for drilling and operating gas and oil wells in Ohio, Pennsylvania, and New York do not prevent the hazard of overpressuring the annulus of a well. There are some municipalities, such as the city of Jamestown, New York, that have established special requirements for gas- and oil-well construction in order to protect the aquifers that they tap for municipal-water supplies. Although in the case of Jamestown the hazard of overpressuring an annulus was considered, the problem was not addressed in the actual requirements established in 1982. In 1985, however, new regulations required that the annulus of new wells drilled in that aquifer be filled with cement and left open to the atmosphere.

Many cases of subsurface contamination of fresh-water aquifers could be avoided if the hazard of overpressuring gas- and oil-well annuli were

[a]Professor of Geology and Environmental Science, Allegheny College, Meadville, Pennsylvania 16335.

Received October 1984, revised February 1985, accepted March 1985.

Discussion open until November 1, 1985.

understood. The purpose of this paper is (1) to explain why overpressuring of gas- and oil-well annuli creates a hazard with respect to contamination of fresh-water aquifers, and (2) to describe steps that might be taken to reduce that contamination hazard.

CONSTRUCTION OF GAS AND OIL WELLS

Gas Wells

In eastern Ohio, northwestern Pennsylvania, and western New York the surface casing—usually 8⅝ inches in diameter—is installed to a depth of 100 to 600 ft. For instance, New York requires that the surface casing, or waterstring, extend 50 ft below the deepest potable fresh-water level or, if this depth is unknown, to a minimum of 450 ft below the ground surface (Moody and Associates and National Water Well Association, 1982). In Pennsylvania, gas wells 3000 to 5000 ft deep must have a minimum of 400 ft of surface casing. Typically, cement is forced down through the surface casing and circulated up the outside of the pipe to the ground surface in an effort to further seal off the zone of fresh-water flow from the well and to form a foundation for well construction (Figure 1A). The cement plug inside the surface casing is then drilled out and a somewhat smaller-diameter hole is drilled down through the target zone, which in this region is usually the Silurian Medina Group.

A 4½-inch-diameter production string is set in the hole, and cement is pumped down through this string and forced up the outside of the pipe. In most instances, the volume of cement used is only

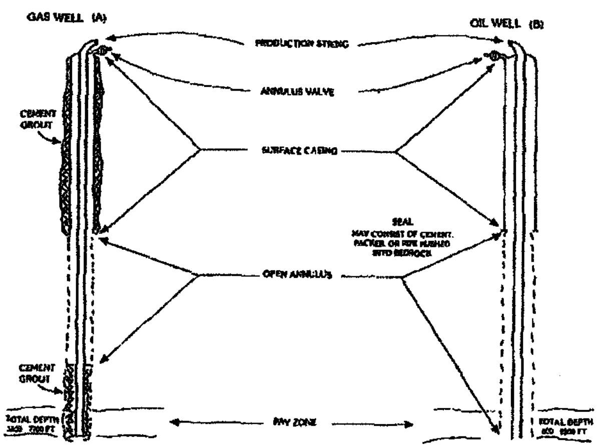


Fig. 1. (A) Construction of a typical Medina gas well. Note uncemented annulus between cemented surface casing and production-zone cement. (B) Construction of a typical oil well in the Bradford, Pennsylvania district. Actual depths differ for different oil fields (from Waite and others, 1983).

sufficient to fill the annulus between the production string and the outside of the hole to several hundred feet above the Medina. In most gas wells this leaves an open (uncemented) annulus of roughly 2000 ft between the bottom cement grout and the surface string grout. Some of the strata penetrated by the open annulus are sufficiently permeable that salt water (brine) contained in them enters the annulus. Likewise, there is often natural gas in one or more of the formations open to the annulus. The annulus provides an avenue by which mixing can occur among formations penetrated by the uncemented well bore.

Oil Wells

The surface casing used in oil wells to prevent fresh water from entering the well also reduces the hazard of the well contents contaminating the zone of fresh water (Waite and others, 1983). In the northwestern Pennsylvania Bradford and Venango oil fields, the surface casing usually ranges from 200 to 600 ft in length (Figure 1B). Although in some oil wells the surface casing is sealed off from the strata it penetrates by forcing cement up the outside of the surface casing, the bottom of the surface casing may alternately be simply set in cement spotted at the bottom of the hole, set in a packer, pushed into the bedrock (Waite and others, 1983) or filled with drilling mud. Below the surface casing the well is open. As with the deep gas wells, this open hole provides an avenue for movement and mixing of the contents of strata penetrated by the hole. In the case of these oil wells, some mixing of water from aquifers penetrated by the surface casing might also occur along the outside of the surface casing because cement grout is often not placed there.

OVERPRESSURING OF GAS- AND OIL-WELL ANNULI

As mentioned before, natural gas often occurs in shallow strata penetrated by the open annulus of an oil and/or gas well. The gas entering the annulus may be from a formation at sufficient depth that the pressure on the gas is a few hundred psi. This gas will flow up the well to the surface as long as there is a decreasing pressure gradient in that direction. However, the annulus is often closed or restricted, preventing the free escape of the gas from the annulus. This results in a buildup of pressure in the annulus.

Among the reasons for closing an annulus which contains gas are a desire to control the discharge of the gas so that it can be (1) fed into a pipeline with the deeper gas being produced from the well, or (2) used as a household fuel by the person on whose land the well is located. Other reasons for closing the annulus include avoidance of the hazard that gas issuing freely from the top of the well might pose to persons near the well.

If the flow of gas from the annulus is restricted and the pressure within the annulus exceeds the normal pressure in any strata open to the annulus, the annulus is considered to be overpressured. The theoretical normal hydrostatic pressure (and hence the theoretical threshold of overpressuring) can be calculated easily by multiplying the depth below the water table of a given stratum by the hydrostatic pressure gradient due to the overlying water (0.43 psi/ft). Thus, theoretically, strata exposed in an annulus 500 ft below the water table should have a normal pore pressure of 500 ft × 0.43 psi/ft = 215 psi. This calculation, of course, takes into account only the hydrostatic pressure due to depth below the water table. It does not include hydrodynamic pressure which would result in a pressure lower than the theoretical pressure in recharge areas and higher than theoretical in discharge areas or confined aquifers. At present, there is no simple means of routinely measuing the actual pore pressure (hydrodynamic plus hydrostatic pressure) in strata penetrated by an open annulus. In order to illustrate the mechanism by which overpressuring an annulus can result in contamination of the zone of fresh-water flow, only the theoretical hydrostatic pressure will be taken into account in the examples that follow. The hydrodynamic pressure, which varies locally, would cause departures from these theoretical calculations and would change the actual threshold of overpressuring.

Continuing with the example of a hypothetical stratum, exposed in an annulus at a depth of 500 ft below the water table, let's further assume that this stratum is somewhat permeable and that it contains saline water. Also, let's assume that there is gas entering the annulus from strata at a depth of about 1200 ft which have a formation pressure of 400 psi. If the annulus of this hypothetical well is shut in, a pressure gauge on the top of the annulus would show that gas pressure within the annulus stabilized at about 400 psi. If only gas were present in the annulus above the somewhat permeable stratum at 500 ft, pressure on this stratum where it is exposed to the annulus would also be about 400 psi, which is nearly double the theoretical hydrostatic pressure that previously existed there (Figure 2). This results in the creation of a pressure gradient between the somewhat permeable stratum and the water table. If the somewhat permeable stratum is 500 ft below the water table, and the pressure within this stratum at the well bore is raised to 400 psi, the hydrodynamic or driving head of 185 psi (400 psi − 215 psi = 185 psi) in excess of the theoretical hydrostatic pressure is equivalent to a head of 430 ft of water (185 psi divided by 0.43 psi/ft = 430 ft) (see Figure 2). This sets up a hydraulic gradient of +0.86 between the somewhat permeable stratum and the overlying water table (430-ft head divided by 500 ft). As a result of this strong upward

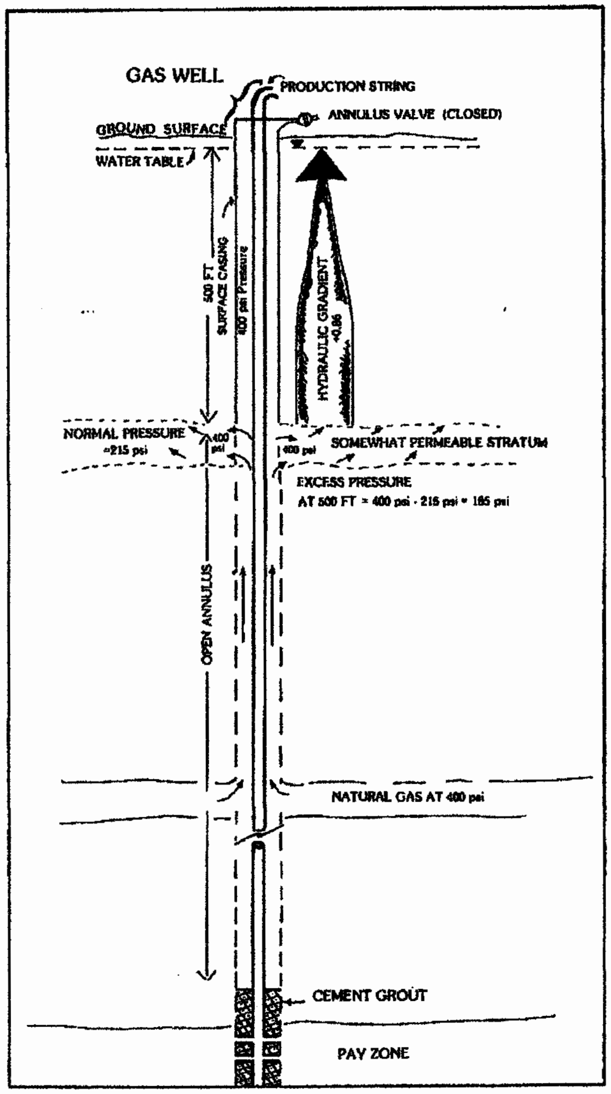


Fig. 2. Overpressuring of a well annulus by gas which is prevented from escaping to the atmosphere by a closed annulus valve. The excess pressure (185 psi) in the stratum exposed to the annulus at the 500-ft depth results in a pressure gradient of +0.86 between that stratum and the overlying water table.

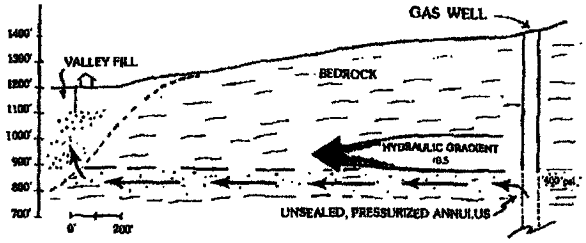


Fig. 3. An overpressured annulus located on a valley wall or upland near a valley filled with glacio-alluvial sediment may result in flow of the annulus contents laterally into valley-fill aquifers. Under the conditions depicted, the pressurized annulus has increased the normal hydraulic gradient by more than 600%.

hydraulic gradient, the contents of the somewhat permeable stratum may flow outward and upward from the annulus toward the overlying zone of fresh ground-water flow. Thus, even in a gas or oil well constructed so that the well is isolated from the zone of fresh ground-water flow by a surface casing, contaminants can be forced outward and upward from the annulus below the surface casing if the well annulus is overpressured.

It is important to note that overpressuring the annulus sets up the hydrodynamic gradient which provides the driving force for movement of contaminants into the overlying aquifers. In order for contamination to actually take place, however, there must be a sufficiently permeable pathway from the annulus up to the zone of fresh-water flow. This permeability pathway could simply be the result of the primary permeability of the strata between the annulus and the fresh-water zone, or it might be the result of secondary permeability in the form of joints or fractures [i.e., fracture traces (Harrison, 1983) or abandoned, unplugged wells]. In the case of overpressured annuli located near deep valley fills, rather than an upward flow of contaminants, the annulus contents may flow laterally through the bedrock into adjacent valley-fill sediments. In Figure 3, for example, which depicts conditions frequently found in the Glaciated Appalachian Plateau, the movement of contaminants from the pressurized annulus may follow a flow path laterally through permeable strata until it enters the valley-fill sediments where upward flow into the overlying aquifers may occur. Although a permeability pathway probably does not exist between the annulus of most gas and oil wells and the zone of fresh-water flow, it is very difficult to determine if such pathways do exist at a given well site; thus, the risk of contaminating fresh ground water will exist if a hydraulic gradient to the surface is created by overpressuring the annulus.

To demonstrate the contamination of the zone of fresh-water flow by wells with overpressured annuli, a two-dimensional ground-water flow model (Harrison, 1975) was used. In the first run, water was pumped through the upper part of the model under a hydraulic gradient of 0.09 (3.5 inches of head loss over a 36-inch-long flow path). A cased "gas" well penetrated the zone of fresh ground-water flow, the watertight surface casing extending to a depth roughly twice the thickness of the fresh-water flow zone, as determined by the movement of dye (Figure 4A). Below that the gas well had an open annulus (i.e., the pipe used for the model well had holes in it below that depth). Once dye movement in the zone of fresh-water

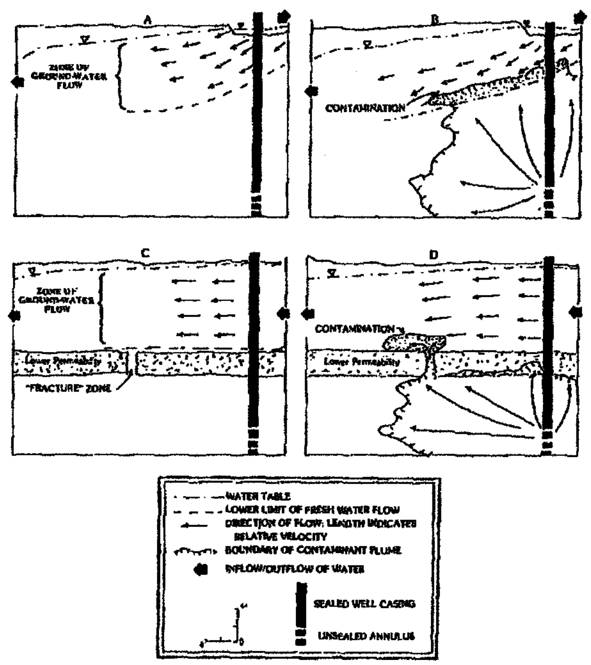


Fig. 4. Sketches made from photographs of a two-dimensional ground-water model to demonstrate the movement of contents of an overpressured annulus up into the zone of fresh ground water. (A) Run 1. Model filled with highly permeable sand. Zone of ground-water flow established by dye movement. (B) Run 1. Hydrodynamic head on annulus equivalent to an annular pressure about 185 psi above normal at the bottom of a 500-ft-long surface casing. Contaminants from the annulus flow up into the zone of fresh ground water. (C) Run 2. Model filled with layers of sand of two different permeabilities. Lower-permeability layer is breached by a higher-permeability zone representing a fracture zone. (D) Run 2. Contents of annulus contaminants overlying zone of fresh-water flow. Hydrodynamic head on annulus equivalent to an annulus pressure about 430 psi above normal at the bottom of a 500-ft-long surface casing.

flow had established that water surrounding the open annulus of the gas well was not flowing, dyed water of a different color was introduced into the gas well under a head sufficient to create a hydraulic gradient of +0.8 between the bottom of the well casing and the overlying water table. This hydraulic gradient of +0.8 is roughly equivalent to the excess annulus pressure of 185 psi used in the previously-discussed example of an annulus open at a depth of 500 ft below the water table (+0.86 = x divided by 500 ft = 430 ft; 430 ft times 0.43 psi/ft = 185 psi).

The dyed water from the gas well, representing the pressurized contents of the annulus, moved outward and upward quickly, toward the overlying zone of fresh ground-water flow (Figure 4B). Because permeability in the model was uniform, contaminants issuing from the annulus traveled much faster than the overlying normal ground-water flow, in a velocity ratio predicted by the ratio of the two hydraulic gradients (0.86 divided by 0.09 = 9.5 times faster flow for the contaminants). This clearly demonstrated what had been postulated on a theoretical basis, namely, that the pressure gradient created by an overpressured annulus can cause the contents of an annulus to move upward into the overlying zone of fresh ground-water flow even if the properly-installed surface casing extends below the zone of fresh ground-water flow (Figure 4B).

In the model the annulus content was a fluid (water). In an actual well, this fluid in itself would most likely be a contaminant, because it would be comprised of brine and/or chemical additives used in drilling and/or development of the well. If no liquid were present in the annulus at the level where the overpressured annulus contents were moving outward from the annulus, then the gas causing the overpressuring would enter the surrounding strata and move along the pressure gradient in the ground water. If more gas enters the ground water than can be dissolved in the water under the existing temperature and pressure, then there will be polyphase flow. Polyphase flow of a gas and a fluid containing dissolved gas would be more complex than the flow described in this paper. This paper deals primarily with the flow of ground water containing gas in solution.

A second run was made with the model to demonstrate the importance of natural fracture zones as permeability pathways for the upward movement of the contents of a pressurized annulus. Within a fracture zone, which is vertical, roughly 30 to 60 ft wide, and up to a mile in length, there is an unusually high density of vertical hairline fractures (joints) within the strata. This results in a zone of greater permeability along the plane of the fracture zone than in the less-fractured earth material around it. If an overpressured annulus is located close to a fracture zone, the flow of the annulus contents up into the zone of fresh water will be greatly facilitated. To demonstrate this in the model, upper and lower zones of relatively high permeability were separated by a lower-permeability zone. Out some distance from the well, the lower-permeability layer was breached by a vertical zone of high-permeability material representing a fracture zone. Movement of dyed water in the model established the zone of fresh ground-water flow, which did not extend down into the layer of lower-permeability sediment (Figure 4C). As in the previous run, the surface casing of the gas well extended below the zone of fresh-water flow by about twice the thickness of that zone. Dyed water was introduced into the gas well under a head sufficient to produce a maximum hydraulic gradient of about +2.0, which would be equivalent to an excess pressure at the top of the annulus of 430 psi if the model represented a well with a surface casing 500 ft below the water table, and there were only gas in the surface casing (+2.0 = x divided by 500 ft = 1000 ft of head; 1000 ft times 0.43 psi/ft = 430 psi). Figure 4D shows that again the contents of the overpressured annulus moved outward and upward from the bottom of the surface casing. Because of the presence of the low-permeability layer above the bottom of the surface casing, lateral flow was dominant and more pronounced than in the previous experiment. When the annulus contents reached the bottom of the fracture zone penetrating the low-permeability layer, however, the dye flowed upward through this zone and into the overlying path of fresh ground-water flow.

Based on the above examples, it would seem that the pressure at the top of a well annulus could be monitored and compared to the theoretical hydrostatic pressure at the bottom of the surface casing as an indicator of whether overpressuring of the annulus was taking place. Unfortunately, the pressure at the top of the annulus may represent only a fraction of the total pressure at the bottom of the surface casing. In the example of a 500-ft-deep surface casing cited earlier, it was assumed that there was no liquid in the surface casing above the open annulus. Had there been liquid there, the pressure added by the head of that liquid above the 500-ft depth in the casing would not be measured by the annulus pressure gauge. For example, if the pressure on an annulus gauge at the top of a 500-ft surface casing read 200 psi, one might have assumed that the annulus was not overpressured because the theoretical hydrostatic pressure at the bottom of the surface casing should be on the order of 215 psi, using a theoretical gradient of 0.43 psi/ft (see Figure 5). But what if the surface casing in question had 300 ft of water in it? The pressure at the bottom of the surface casing would now be 200 psi, as reflected by the gauge which reads the gas pressure, plus an additional 129 psi due to the head of the water (0.43 psi/ft times 300 ft) (Figure 6). Thus, the total pressure at the bottom of the surface casing is actually 200 psi + 129 psi = 329 psi, which greatly exceeds the theoretical hydrostatic pressure of 215 psi. This excess pressure would create a hydraulic gradient of roughly +0.6 between the contents of the annulus at the bottom of the surface casing and the overlying water table (Figure 5). Therefore, monitoring the gas pressure at the top of the annulus is insufficient unless the level and density of fluid in the annulus are also known, and that resulting pressure is calculated and added to the gauge pressure. For a well with a surface casing which extends 500 ft below the water table, Figure 6 shows the relationship between gauge pressure at the top of the annulus, fluid level in the well, and total pressure at the bottom of the surface casing. These calculations were based on the assumptions of a theoretical pressure gradient of 0.43 psi/ft of water below the water table.

Pressurizing the annulus also affects the contamination hazard by increasing the amount of gas that can be carried by liquids leaving the annulus. The solubility of methane in water at atmospheric pressure is about 21 ppm. Solubility increases with pressure, however. For instance, if the pressure is increased from atmospheric to 400 psi (27 atmospheres), the methane that can be dissolved in fresh water increases by more than 27 times (solubility is directly proportional to pressure). Therefore, pressurizing an annulus will increase the amount of methane that might be carried in solution from the annulus by fluids moving outward and upward from the annulus due to the hydraulic gradient created by overpressurization.

The relationship of pressure to the solubility of methane in ground water also explains phenomena frequently observed in cases of aquifers contaminated with methane. In cases where methane is moving through an aquifer in the form of a gas dissolved in water, when the water enters a water well which is being pumped, the water will undergo a decrease in pressure. Thus, there will be a decrease in the solubility of the gas. If the water was saturated with gas before entering the well, there will be a release of the gas into the well bore and up through the well vent when the water level in the well is lowered due to pumping. For this reason, it is important in areas where gas is present in aquifers that water wells be vented to the open air. In some cases the first indication that homeowners have that methane is contaminating their water supply is a minor explosion in their well pit or pump house. Water wells located within basements or in crawl spaces can represent a particular hazard under these conditions. The reduction of solubility of gas as pressure is reduced also explains the frequent tendency of water con-

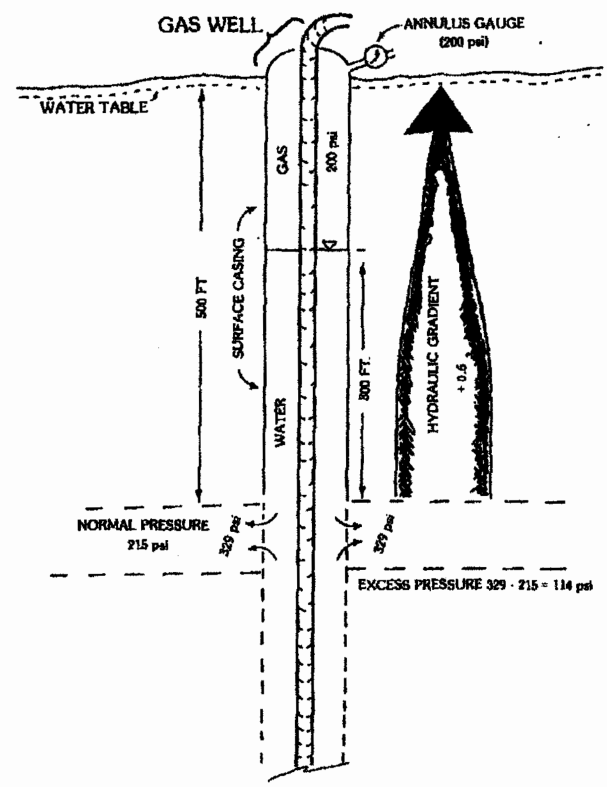


Fig. 5. Excess pressure in strata exposed to the annulus at the bottom of a 500-ft-long surface casing. Total pressure at the 500-ft depth is 200 psi from the gas and 129 psi from the 300-ft column of water in the surface casing. The 114 psi excess pressure in the stratum at the bottom of the surface casing results in a hydraulic gradient of +0.6 between the bottom of the surface casing and the overlying water table. A theoretical pressure gradient of 0.43 psi/ft was used to calculate the estimated normal pressure in the stratum exposed to the annulus at the bottom of the surface casing.

taining methane to visibly bubble or fizz for several seconds after a glassful is drawn from a household faucet (this bubbling may be masked by aerator-type faucets).

In some extreme cases of overpressuring of oil- and gas-well annuli, yet another hazard may exist. If the pressure in fluids in the annulus below the surface casing becomes too great, propagation of existing fractures in some strata might occur. If this were to happen, secondary permeability would be increased, thus increasing the rate at which the contents of the annulus could flow outward and upward.

Guidelines for injection wells provided by the U.S. Environmental Protection Agency indicate that if a fracture gradient of 0.73 psi/ft of depth is exceeded, propagation of existing fractures might occur in some instances (U.S. Environmental Protection Agency, 1984). Little appears to be known about the fracture gradient for shallow formations in this region, however. As more is learned, we may find that the fracture gradient of specific formations is more or less than 0.73 psi/ft. To illustrate the relationship of overpressurization of a well annulus to the possible propagation of fractures, however, a fracture gradient of 0.75 will be assumed in the following example.

Referring again to a well with a surface casing that extends 500 ft below the water table, the hypothetical maximum pressure that should be exerted on that formation in order to avoid increasing its permeability due to propagation of fractures would be 0.75 psi/ft times 500 ft = 375 psi. Looking at Figure 6, it is apparent that if there were no water in the annulus within 500 ft of the water table, the maximum pressure on the annulus gauge should not exceed 375 psi. If there were 200 ft of water above the 500-ft level in the annulus, then a reading of slightly less than 300 psi gas pressure at the top of the annulus might indicate danger of fracture propagation in the formation exposed to the annulus at the bottom of the surface casing in the hypothetical case described.

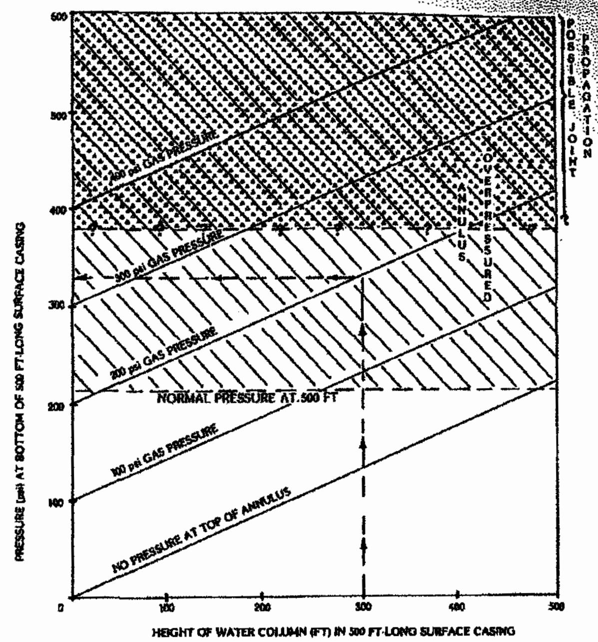


Fig. 6. Total pore pressure at the bottom of a 500-ft-long surface casing with varying gas pressure and varying amounts of water in the annulus above the bottom of the surface casing. The "normal" pore pressure in strata exposed to the annulus at the 500-ft depth was estimated by using a theoretical pressure gradient of 0.43 psi/ft. The example (arrows) shows that 300 ft of water in the surface casing with a 200-psi gas pressure above it results in a pressure of 329 psi at the bottom of the 500-ft-long surface casing.

REDUCING THE HAZARD OF GROUND-WATER POLLUTION DUE TO OVERPRESSURIZATION OF WELL ANNULI

From the ground-water protection perspective, the simplest and most complete solution to reducing the hazard of annulus contents contaminating fresh ground water is to eliminate the annulus. This might be done in the case of a deep gas well by filling the area between the production string and the surrounding well bore with cement. In the case of oil wells, it might be necessary to set a packer above the uppermost oil-producing zone or set surface casing or an intermediate string of casing to a depth immediately above the pay zone(s) and then cement back to the surface. Although in some cases there is a possibility that gas may have sufficient pressure to flow up through the cement before it has cured, these cases can be identified before cementing, and preventive steps can be taken (Sutton and others, 1984).

Although the entire annulus of a few gas wells in this region has been filled with cement, this is not the general practice because of the cost of the added cement and the elimination of gas production from strata exposed to the annulus above the Median pay zone. Some concern also has been expressed that an annulus filled with uncured cement might exert sufficient pressure to fracture the pay zone and invade it with cement. Also, if solution of salt zones has occurred during drilling, there could be considerable loss of cement to these zones. Some suggest that simply filling the annulus with drilling mud or gel and leaving the annulus vent open is a satisfactory precaution. A major drawback of this latter precaution is that there is no assurance that the annulus vent will not be closed at some time in the future.

An alternative practice is to operate the oil or gas well so that the pressure in the annulus never exceeds the normal pressure in the strata exposed to the annulus. As explained above, however, this is not as simple as putting a pressure gauge on the top of the annulus because, (1) the level and density of fluid in the annulus would also have to be monitored and taken into account, and (2) only the theoretical "normal" pressure can be calculated—the actual "normal" pressure at some level within the annulus is not generally known. Thus, if fluid level is not monitored, the only completely safe gas pressure at the top of the annulus is atmospheric, which means leaving the annulus vent open. If there is concern over the hazard at the ground surface from gas escaping from the annulus, then flaring the gas or installing a riser pipe which extends several feet above the ground might provide a practical solution.

CONCLUSIONS

Operating an oil or gas well in a way which causes the pressure in the annulus to exceed the normal pressure below the surface casing will create a positive hydraulic gradient between the annulus and the overlying zone of fresh-water flow. This can cause contaminants in the annulus to flow outward and upward into the zone of fresh ground-water flow if a permeability pathway exists. The hazard of the contents of the annulus contaminating overlying fresh ground water is further enhanced by the fact that the solubility of methane in water is increased as annulus pressure increases. In cases of extreme annulus overpressuring, possible propagation of fractures in strata exposed to the annulus below the surface casing might increase the rate at which contaminants can flow from the annulus into the overlying fresh ground water.

Although the creation of a positive hydraulic gradient between the annulus and the overlying fresh ground water will result in contamination only if there is a permeability pathway up into the zone of fresh-water flow, the presence of these permeability pathways cannot be predicted with assurance. Thus, the risk of contaminating fresh ground water exists, and steps to reduce this risk should be taken with all wells.

The hazard of contaminating fresh ground water with the contents of the annulus of oil and gas wells can be greatly reduced by either (1) eliminating the annulus by filling it with cement, or (2) operating the well in a manner that does not allow the normal pressure in formations exposed to the annulus to be exceeded.

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Certificate of Service

I, the undersigned, certify that the foregoing *Petition for Review* of UIC Permit No. PAS2D020BCLE was filed with the Environmental Appeals Board via Certified First Class Mail, return receipt requested and served on the following via Certified First Class U.S. Mail, return receipt requested:

Permitting Authority

United States Environmental Protection Agency
Region III
Attention: Shawn M. Garvin, Regional Administrator
1650 Arch Street
Philadelphia, PA 19103-2029

Applicant-Permittee

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