SME Annual Meeting
Feb. 27 - Mar. 02, 2022, Salt Lake City, UT

Preprint 22-095

GAS SOURCE DISCRIMINATION METHODS TO IDENTIFY THE OCCURRENCE OF A HYPOTHETICAL, UNCONVENTIONAL GAS WELL BREACH INTO A NEARBY LONGWALL MINE

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ABSTRACT

The National Institute for Occupational Safety and Health (NIOSH) has been conducting research related to unconventional gas wells positioned in abutment pillars associated with active longwall mining in Southwestern PA. The Ventilation and Explosion Prevention Team at NIOSH is working toward predicting and characterizing a hypothetical casing breach and its effect on the safety and health of mine workers, gas well workers, and the general public. An important aspect of this research is to distinguish coalbed gas from shale gas in the mine environment as an indicator of a casing breach. Another non-coal gas source exists in the region in the form of underground gas storage fields which also have the potential to migrate towards mine workings. During a potential gas breach, the addition of excess natural gas to coal mine environments will exceed the anticipated ventilation loading and can create a mine explosion hazard. A methodology has been developed to distinguish these gas sources. Gas samples from the three sources were analyzed by gas chromatography, and interpretive methods were applied to distinguish the populations graphically and statistically. Bivariate plots using the hydrocarbon index and the normalized molecular ratios showed that the sources occupy different regions of the graphs. All samples of non-coal gas contained under 2% CO2, and all coal samples included greater than this amount. A multivariate T-squared (T2) test analysis relating comparing data in pairs showed a low p-value (dimensionality parameter) and a high T^2 test statistic for all comparisons, indicating that these sources are different and distinct gas populations. Ultimately, stakeholders from the mining and gas production industries can utilize this method to identify gas sources and a potential casing breach.

INTRODUCTION

Background

In Southwestern Pennsylvania, longwall mining is continuing to produce coal from underground mines. The primary unit of interest for most underground mining activity in the region is the Pittsburgh coal bed. An additional energy source in the region is the Marcellus shale where advances in the unconventional gas industry and market forces have created a demand for this product. The mineable coal and desirable shale gas well reserves are often positioned near each other such that operating coal mines can overlie well production targets. In the past 15 years, more than 1,500 unconventional shale gas wells have been drilled through current and future coal reserves in Pennsylvania, West Virginia, and Ohio. Typical Marcellus shale depths are in the range of about 2,100 m (7,000 ft) with a general trend of dipping to the southwest. The Pittsburgh coal bed mining depth is commonly about 300 m (1,000 ft), but considerable topographic relief can be found.

When optimal reserves for coal mining and unconventional gas wells are superimposed on each other but stratigraphically separated by thousands of meters, these wells can be positioned very near active longwall mining. Consequently, plans were developed to drill unconventional gas wells through longwall abutment pillars so that ground movement associated with mine subsidence did not damage the integrity of the well casing. Guidance documents were produced by the Pennsylvania Department of Environmental protection (PADEP) and participating stakeholders from the regulatory agencies and industry in 1957 before the advent of longwall mining (1). In 2017 there was an interim update to this guidance document which is now published (2). NIOSH researchers are collaborating with the unconventional gas and coal mining industries to provide an update to this guidance based on scientific data obtained both on ground control and ventilation behavior. If a hypothetical gas well breach was to occur, it would potentially risk the safety and health of mine workers, gas well workers, and the general public near the site.

Another potential source of non-coal hydrocarbon gas could be from underground gas storage fields which could produce a hypothetical gas inflow to an underground mine. An underground gas storage field located in Southwestern PA is quite typical for this resource where a former conventional gas reservoir is now used for the storage of natural gas injected from other sources. Old, abandoned wells could be unexpectedly encountered by mining near these sites, and mining into such a well could form a conduit for gas transport from the pressurized reservoir. A different means of possible methane introduction to an underground mine environment could be through fractures in the overburden.

EXPERIMENTAL

Study area

The focus of this research study is on Southwestern PA within the Northern Appalachian Basin where the intersection of coal mining, unconventional gas, and underground gas storage industries are regularly working cohesively. The original research plan was to acquire gas samples from field locations and analyze the acquired gas samples via an independent analytical lab. With the advent of Covid 19 health-related restrictions and precautions, this activity was limited and could not be performed by NIOSH researchers. Alternate means of obtaining data were sought, and NIOSH researchers relied on published databases, prior publications, research stakeholders, cooperators, active research projects, and collaborators for the gas data included in the reported analyses.

A database produced by the U.S. Geological Survey was a primary source of information for shale gas (3). The data set provided unconventional gas production information which was then filtered to include only production from the Marcellus Shale and the Northern Appalachian Basin of Pennsylvania, West Virginia, and Ohio. Data for coalbed methane (CBM) were acquired from published reports for the Pittsburgh, Sewickley, and Uniontown coal beds, which all may produce gas emissions into Pittsburgh coal bed longwall mines (4). Some of these data were produced from gas content testing results using either NIOSH's Modified Direct Method technology (MDM) (5) or the Direct Method (DM) approach produced by the U.S. Bureau of Mines (USBM) in the 1970s and 1980s (6). A portion of these MDM results are from active research projects and are not yet published.

All gas compositions can vary from an individual source. Since the underground gas storage field is made up with gases injected from a range of natural production gas streams, the gas composition range can be great, reflecting the variety of gas injected and extracted.

Conventional natural gas from the depleted reservoir can also be present in combination with injected gas. Therefore, studies characterizing gas from this source have sometimes used stable isotopic data to relate samples to their genetic source (7).

Organic matter characterization

Prior research suggests possible ways to relate gases to their sources and to distinguish them compositionally (8-9). Volatile matter including gaseous byproducts are produced from organic matter through increasing thermal maturity. The organic matter type (kerogen) differs between coal and shale. The Devonian shales contain type II organic matter, which is made up of material relatively high in hydrogen and aliphatic compounds, typically leaf cuticle and spores, with some marine-derived material as the dominant component in the shales (Figure 1). Hydrogen to carbon and oxygen to carbon ratios are shown as "H/C" and "O/C", respectively.

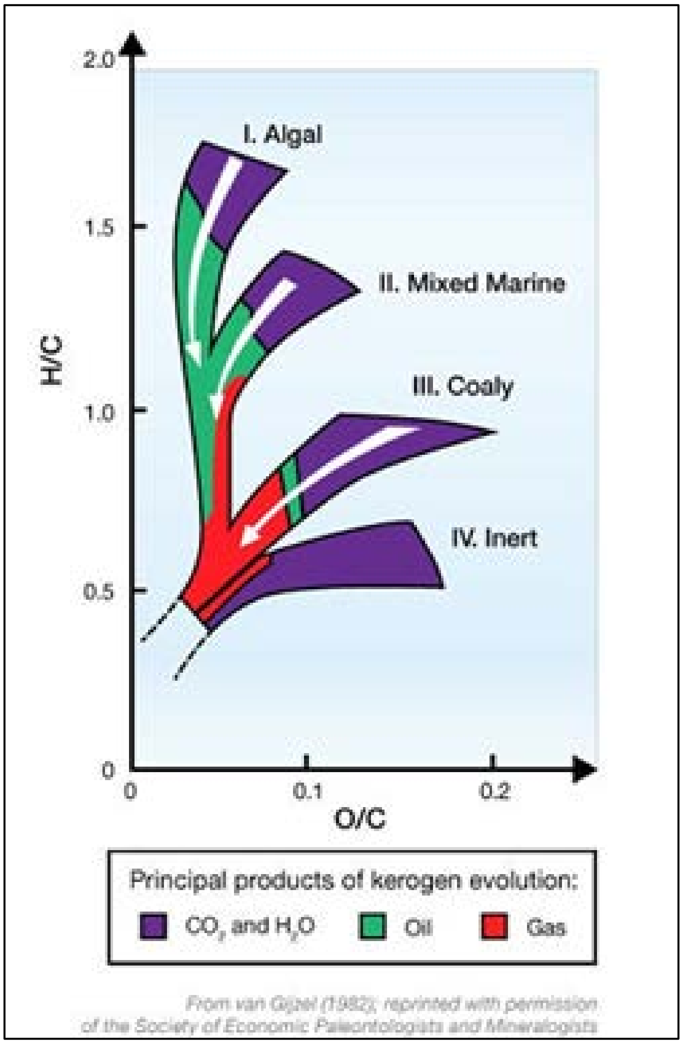

Figure 1. Modified Van Krevlen diagram showing organic matter types and changing composition with increasing thermal maturity (10).

The Pennsylvanian-age coal seam organic matter in the Northern Appalachian Basin is made up of primarily type III organic matter. Type III organic matter has a higher terrestrial plant content with typically a lower gas generation potential compared to type II. These differences in organic matter types can produce a range of chemical byproducts.

The organic matter present responds to heat and pressure, which changes its composition through the loss of volatiles (Figure 2). Both organic matter types yield carbon dioxide, methane, and water that are produced with increasing thermal maturation. The coal rank series is shown increasing in thermal maturity from peat to graphite with the conventional rank parameter vitrinite reflectance in oil (Ro) shown increasing with rank. Vitrinite is one of three coal maceral groups and is most commonly used in rank studies. Changes in the organic matter elemental composition for carbon and hydrogen are shown as "C" and "H". The source material can also respond in different ways to the rate of organic matter heating, which can be related to the geothermal gradient or other means of increasing thermal maturity (e.g., presence of igneous intrusions) (11). An early microbial phase of gas generation is common in type III kerogen and often followed by the thermogenic phase of gas generation. The behavior of the methanogenic bacteria produces a change in the distribution of stable carbon isotopes in the produced gas from what is found in nature. This behavior can provide a mechanism for identifying type III kerogen gas sources compared to type II kerogen gas using stable isotope analysis (8) (12).

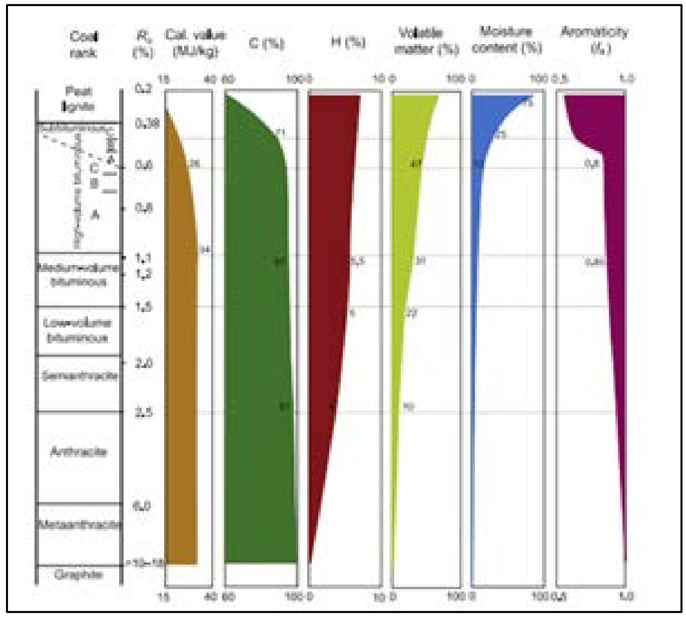

Figure 2. Organic matter changes with increasing coal rank (9).

DISCUSSION AND RESULTS

Organic matter characterization

Prior research has depicted rank on the basis of vitrinite reflectance, for both Devonian shales and Pennsylvanian coal in the Northern Appalachian Basin (Figure 3). Figure 3A shows vitrinite reflectance values for both the Pennsylvanian age coals and the Devonian shale. In Southwestern PA, these coal bed ranks are about 0.8 to 1.1 Ro. The Devonian shale was determined to have a thermal maturity as measured by vitrinite reflectance of about 1.5 to 2.5 Ro in this region (13). In Figure 3B, the same region is shown with the carbon alteration index (CAI) maturity data for the coal units. The CAI shale rank data show slightly modified rank contours. A range of parameters can be used as rank indicators for organic matter (14). In general, different thermal maturation indicators for organic matter may not agree. The mobilization of fluids may have contributed to the observed vitrinite reflectance trends associated with orogenic Alleghenian fluids (15-16).

However, a relatively large rank difference between the Pennsylvanian and Devonian age organic matter persists between the shale and coal organic matter.

It should be noted that the difference in geologic age between Pennsylvanian coal beds and Devonian shales does not assure the difference in rank found in the Northern Appalachian Basin. The rank achieved by the kerogen within the unit is primarily the product of the burial history, geothermal gradient, and hydrostatic pressures. Figure 4 shows a map view of the Fort Worth Basin with rank and regional structure data. The rank contours show variation in thermal maturity relative to the Ouachita Thrust fold Belt and the Bend Arch (17). The lower rank values for the unit in this location overlap the rank values for bituminous coals in other parts of the state of Texas. With the exception of limited cannel coal resources found in the state, the differences between coal and shale organic matter types persist and may still allow for differentiation of produced gases.

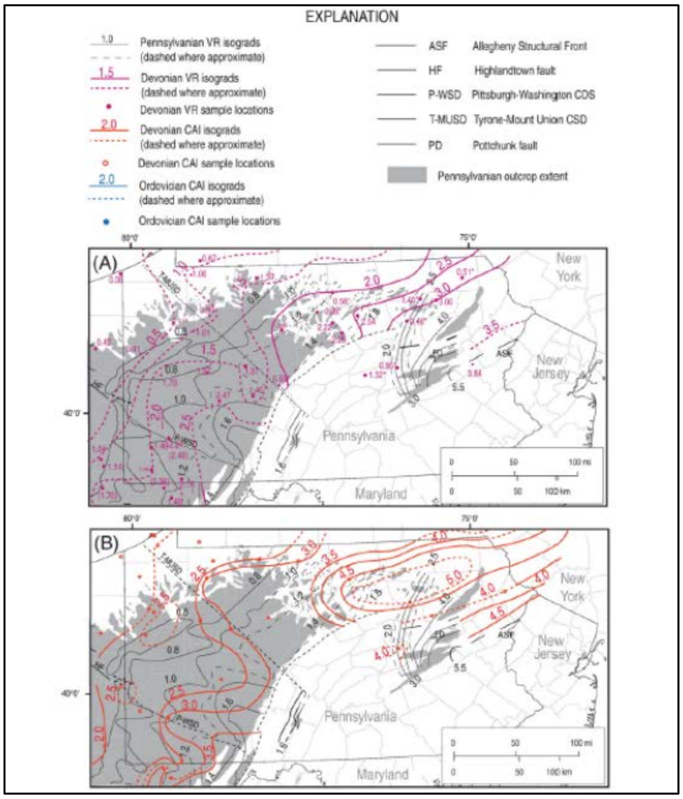

Figure 3. Pennsylvanian age coal and Devonian shale organic matter ranks in Southwestern PA. A: Rank values from reflectance in oil; B: Rank values from CAI index. Modified from Ruppert et al. (13).

Gas analyses

In a prior publication, Schatzel and Su (2020) reported on a limited data set from CBM, shale gas, and underground storage field gas and suggested distinguishing them on the basis of conventional gas chromatography (GC) analysis including hydrocarbons and other molecular ratios. This data set has been updated and includes shale gas data from the Marcellus shale gas produced from wells in PA, WV, and OH. The coalbed gas data from Southwestern PA are reported from published work along with CBM wells or core samples. Underground storage field data are all from wells in Southwestern PA.

Some prior research highlighted a ratio of ethane-to-methane concentrations to distinguish between coalbed methane and shale gas (Smith et al., 2015). Schatzel and Su (2020) proposed using the hydrocarbon index to distinguish these sources. The authors also showed data from molecular concentrations or ratios in bivariate plots to assist in discriminating coal, shale, and underground storage field sources.

New data plots are shown in Figure 5. The hydrocarbon index is plotted on the horizontal axis and often used to distinguish between thermogenic and microbial gases. It is defined, as $CH_4/(C_2H_6+C_3H_8)$ (methane/(ethane+propane)). The carbon dioxide (CO_2) concentration is plotted on the vertical axis. Data from the CBM and shale gas sources can be seen to occupy different regions of the plot. All shale and gas storage field samples were found to have less than 1% CO_2, and all CBM samples contained greater than 2% CO_2 over this amount. Also, all non- coal sources produced a hydrocarbon index less than 100, and most of the CBM samples plotted above this value.

The same data are plotted in Figure 6 using the CH_4/CO_2 concentration ratio with the hydrocarbon index. The logarithmic scale used for the vertical axis in this plot produced a greater spread in the data partitioning coal from non-coal gas sources above and below CH_4/CO_2 ratios of 100. The same behavior described for coal and non-coal samples on the horizontal axis in Figure 5 is repeated. The underground storage field gas samples show very limited variations in gas concentration compared to the Marcellus shale gas samples.

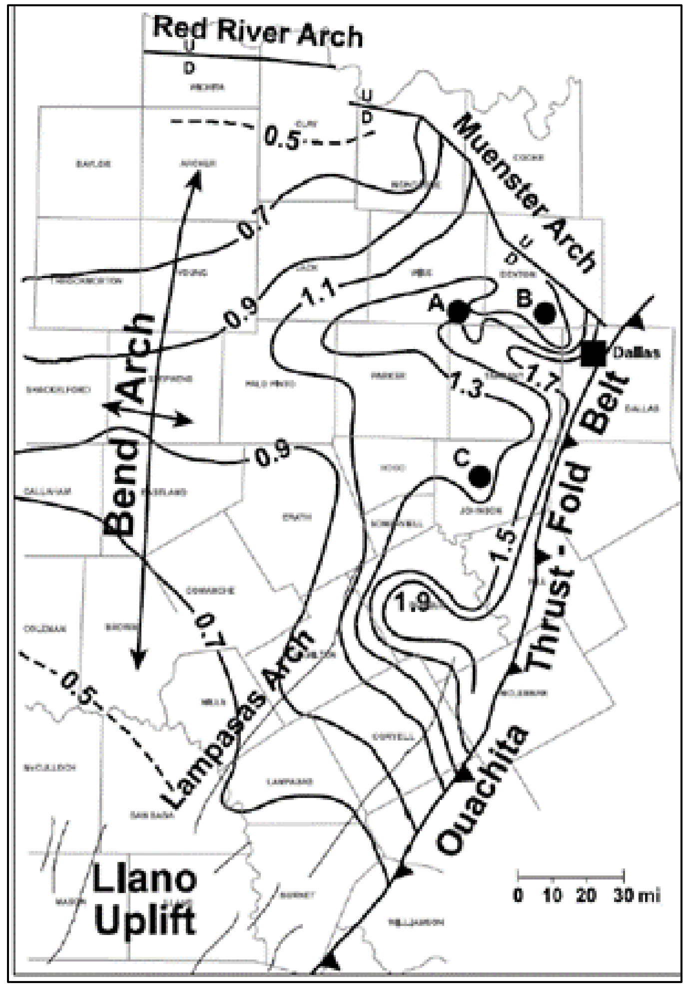

Figure 4. Devonian Barnett shale rank variations Fort Worth Basin, TX (17).

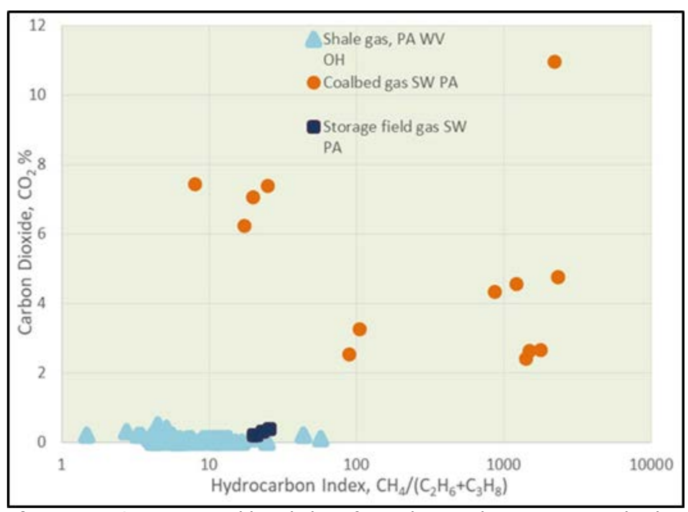

Figure 5. Gas compositional data from three primary sources in the study area with carbon dioxide percentage on y axis. Light blue triangles - shale gas; orange circles - coalbed gas; dark blue squares - underground storage field gas.

Statistical characterizations

The gas data populations were analyzed using a multivariate T^2 test to statistically analyze the potential relationships that exist between the gas populations (20). To analyze the data set, key gas components were chosen to represent the population including CO_2, C_1, C_2, C_3, C_4, and C_5 (methane, ethane, propane, butane, pentane) concentration data. The data were analyzed by comparing the data sets to each other. The results showed a low p-value and a high T^2 test statistic for all comparisons. More specifically, the T^2 value ranged from 8.142 to 47.30, and the p-value ranged from 6.02 x10^{-7} to 2.2 x 10^{-16}. The method provides a comparison of the population means and generates an overall statistical conclusion summarizing the between-group differences. The results of the Hotellings analysis show that these three gas populations are separate and distinct from each other (20).

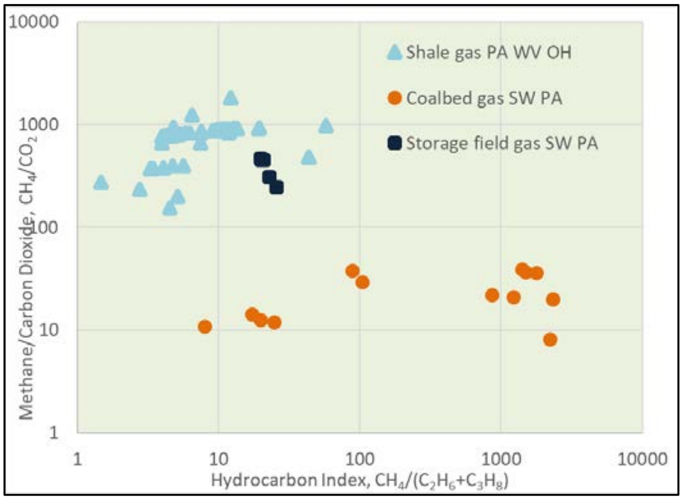

Figure 6. Gas compositional data from three primary sources in the study area with methane-carbon dioxide ratio on y axis. Light blue triangles - shale gas; orange circles - coalbed gas; dark blue squares - underground storage field gas.

Application of a method for distinguishing sources

The proposed method of analysis for distinguishing gas sources would need to be applied in the field to provide data to improve mine and gas well safety. Recent analysis assisted by Thakur (2019) shows how gas from a breached gas well can be transported to mine workings through the fracture network of a coal seam. Well pressures in the analysis were assumed to be 6.9 MPa (1,000 psi), and a range of permeabilities related to the Pittsburgh coal bed were investigated (Figure 7). These permeabilities were anticipated to be modified and increased from typical in-situ values due to the proximity of mining.

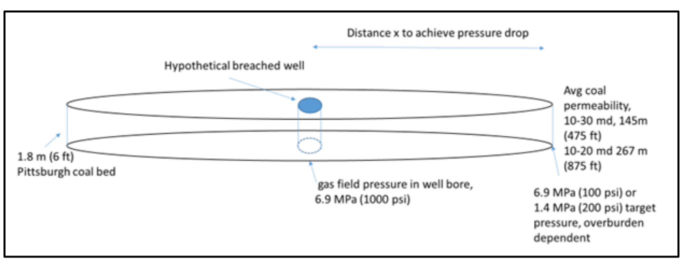

Figure 7. Pressure decay within Pittsburgh coal bed from a hypothetical well breach. Higher permeabilities and lower overburden depths produce slower rate pressure decays over distance. Not to scale. Modified from Thakur (21).

Pressure decays away from the breached well are shown for different overburden depths with anticipated permeabilities (Table 1). Typical well pressures are anticipated to be about 2.4 MPa (350 psi) for flowing wells and 20 MPa (3,000 psi) for shut-in wells. The analysis assumed that the only gas present in the coal bed was to be from a hypothetical well breach, and permeability in the coal bed was assumed to be isotropic. Gas migration away from the well was considered along a radius which could be translated around the well bore (Figure 7). With typical abutment pillar dimensions in the region measuring about 34 m (110 ft) by 76 m (250 ft), pressurized gas from a hypothetical well breach would exceed the dimensions of an abutment pillar. Prior research has shown that permeabilities above the abutment pillars vary with face position, and these sites can far exceed the reported values in this analysis (Watkins et al., 2020). Lower permeabilities are associated with deeper mine overburden depths (Su et al., 2019). Higher permeabilities and higher gas pressures would enhance transport away from the breach potentially making it easier to detect a breach by gas sampling in the abutment pillar. The findings support the approach of sampling of gas from well bores within the pillar as an acceptable means to detect gas from a hypothetical well breach by GC.

Table 1. Gas pressure changes decrease away from a breached well, Pittsburgh coal bed. Pressure decays were calculated to typical levels anticipated by mining operations in the region.

	Permeability range, mD	Breached gas pressure	Coalbed gas pressure near mine	Distance for pressure decline
Shallow overburden, 145 m (475 ft)	10-30	6.9 MPa (1,000 psi)	0.69 MPa (100 psi)	175-303 m (574-994 ft)
Deep overburden, 267 m (875 ft)	10-20	6.9 MPa (1,000 psi)	1.4 MPa (200 psi)	134-190 m (441-624 ft)

A potential gas monitoring scheme is shown in Figure 8 for retrieving gas samples from well pads and underground mines to detect gas leaks from a hypothetical gas well breach. Two small diameter boreholes could be drilled vertically next to the well pad adjacent to both anticipated longwall panels from the surface. Small diameter, short boreholes are also proposed from the crosscuts within the mine (Figure 8). Both sets of boreholes are proposed to be completed as open holes. Sampling can be conducted from the boreholes at variable rates with sampling done more often, such as every day when the longwall face passes the gas well abutment pillar. This frequent sampling regiment can be extended for a distance before and after one of the longwall faces passes the gas well sampling site, perhaps within about 300 m (1,000 ft) or 1.2 times the overburden depth. Analysis of samples by GC is recommended to be kept to a minimum lead time, perhaps no more than 1-2 days. Analytical data are then plotted for discrimination of gas sources (Figures 5 and 6).

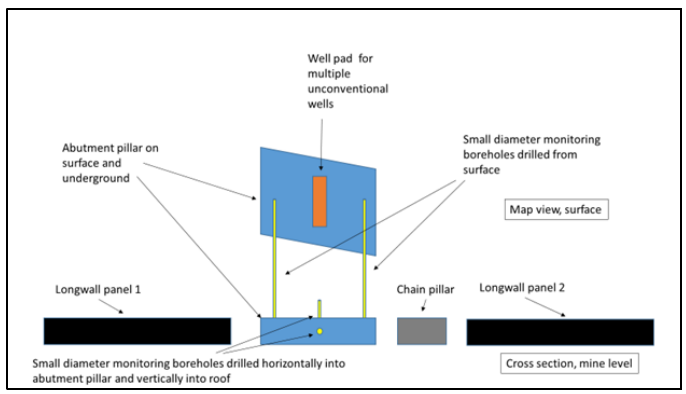

Figure 8. Possible monitoring schematic for mining near flowing or shut-in unconventional gas wells. Not to scale.

SUMMARY AND CONCLUSIONS

Based on conventional coal science and our understanding of the organic matter making up kerogen, there is a theoretical basis to differentiate the three gas sources of interest in Southwestern PA using compositional parameters. Coalbed methane, unconventional shale gas, and underground storage field gas are produced from source material composed of a range of organic matter types that are present at different thermal maturities. It is important to distinguish these gas sources so that if a hypothetical breach of gas into a mine were to occur, it could be linked to the source and causative event. To protect mine and gas well workers from an explosion hazard, it is critical to identify the source of the non-coal gas so that remedial measures could be implemented.

Gas compositional analysis results are presented from GC methods consisting of determinations of atmospheric and hydrocarbon components present in the samples. Although other gas analysis methods can be very valuable in distinguishing these sources, combining GC data with interpretive methods has shown promising results for the distinguishment of these sources.

Using CO_2 concentrations, the hydrocarbon index, $C_1/(C_2+C_3)$, and other molecular ratios, the compositional data were shown to occupy different regions on bivariate plots. A multivariate T^2 test showed the three gas populations to be distinct and provided further support to the graphical discriminations. These interpretations of gas data could be used to identify the presence of non-coal gas in a coal mine or near a surface gas well pad.

A framework for conducting gas sampling near the interface of a production gas well pad and active mining is proposed. The technique utilizes small diameter boreholes in strategic locations near this interface to acquire gas samples for analysis with gas wells under flowing or shut-in conditions and

sampled most frequently when the longwall face is near the well site. Data plots from the analyzed samples can reveal the gas source. Any indication of a change from the baseline of coal strata gas could be used to initiate a potential range of remedial procedures to re-establish safe mine and gas well conditions.

DISCLAIMER

The findings and conclusions in this paper are those of the authors and do not necessarily represent the official position of the National Institute for Occupational Safety and Health, Centers for Disease Control and Prevention. Mention of any company or product does not constitute endorsement by NIOSH.

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