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TITLE Analysis of health and environmental risks associated with Marcellus Shale development

PRESENTED BY Austin L. Mitchell

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Abstract

The rapid growth of the shale gas industry has inspired questions concerning attendant apparent and potential short- and long-term health and environmental risks. My research examined three potential environmental and health risks.

(1) For the last half-century the Northeast natural gas market was supplied from major producing areas in Texas, the Gulf Coast, and Canada. Because radon has a short half-life of 3.8 days, the time required to transport the natural gas from these areas to the Northeast resulted in a low-radon product being delivered to homes. As the Northeast gas market transitions to locally-produced natural gas the potential for radioactive decay will diminish and the natural gas being delivered to homes will contain radon at higher levels. I assess the lung cancer risk for people living in homes with unvented gas cooking (approximately half of the homes in the Northeast) and heating appliances, which are in fewer homes. Data on the locally-produced natural gas radon concentration are limited, but for the modeling assumptions considered the radon exposure is predicted to be small compared to typical residential exposures, and additional annual population-level risk will likely be much less than the error in the estimate of annual radon-induced lung cancers. An excess lifetime lung cancer risk $>10^{-4}$ is possible for high gas usage in poorly ventilated settings.

(2) High volume and locally-concentrated surface water withdrawals for Marcellus Shale development may pose a risk to water quality, aquatic and riparian ecosystems, and other uses of water resources. State environmental and interstate water authorities take different approaches to managing these water withdrawals. In the Upper Ohio River Basin, which covers the western third of Pennsylvania, the Department of Environmental Protection requires that all water used

for shale gas development be covered by a water management plan. These plans stipulate the amount and timing of surface water withdrawals from each source as a function of annual stream flow statistics. Neighboring regulatory authorities and some environmental groups favor the use of monthly flow statistics instead, but implementation of these statistics in western Pennsylvania would require more data than are currently available. Because hydrologic data in the Upper Ohio River Basin are sparse, the use of the annual flow statistics is more likely than use of monthly flow statistics to prevent water withdrawals when aquatic ecosystems are under the greatest stress. The annual flow statistic might also result in fewer and smaller occurrences of computed ecodeficits under scenarios of development-related water demands in the future.

(3) Improperly abandoned and orphan gas wells threaten human health and safety as well as pollute the air and water. Pennsylvania currently requires production companies to post a bond to ensure environmental reclamation of non-productive well sites, but the cost of plugging horizontally drilled wells and reclaiming well pads is estimated to be at least a factor of 10 greater than the current well bonds. The economics of shale gas development favor transfer of assets from large entities to smaller ones. With the assets go the liabilities, and without a mechanism to prevent the new owners from assuming reclamation liabilities beyond their means, the economics favor default on well-plugging and site restoration obligations. In addition to increasing the bond amounts, individual well trust accounts are proposed based on a model from the coal industry. Pre- and delayed-funding options (a fee and severance tax, respectively) to pay for future reclamation are examined from the perspective of the taxpayer. The exposure of the taxpayer to these financial liabilities and to a future orphan well problem can be minimized with minimal impacts to the profitability of gas production regardless of which funding option is used.

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Chapter 1: Introduction

Distributed within the pore spaces of Devonian and Ordovician shale in the eastern U.S. are enormous quantities of hydrocarbons that can now be extracted by the use of unconventional drilling and completion technologies. With estimated technically-recoverable natural gas reserves from 2.4 to 5.9 trillion m^3 (*1, 2*), the Marcellus Shale ranks among the world's largest continuous gas fields.

Development of the Marcellus Shale has proceeded rapidly. Pennsylvania is now the sixth largest gas producer in the U.S., and production in West Virginia and Ohio is also growing (*3*). The movement of people, equipment and money to Appalachia and the extraction of gas from shale are having a profound impact on the region, particularly on the people and places closest to development.

The shale gas industry was booming in Pennsylvania when work on this thesis commenced in the fall of 2009. Media commentators described the flux of "landmen," geologists, and drilling crews to the Pennsylvania countryside as a "modern day gold rush." Development proceeded at a rapid pace despite unanswered questions about the health and environmental risks, and a regulatory framework unprepared to deal with them. Figure 1 illustrates the dramatic increase in regional production, particularly in Pennsylvania. It also explains some of the difficulties faced by regulators, whose regulatory capacities had languished in the preceding decades of low production and public interest.

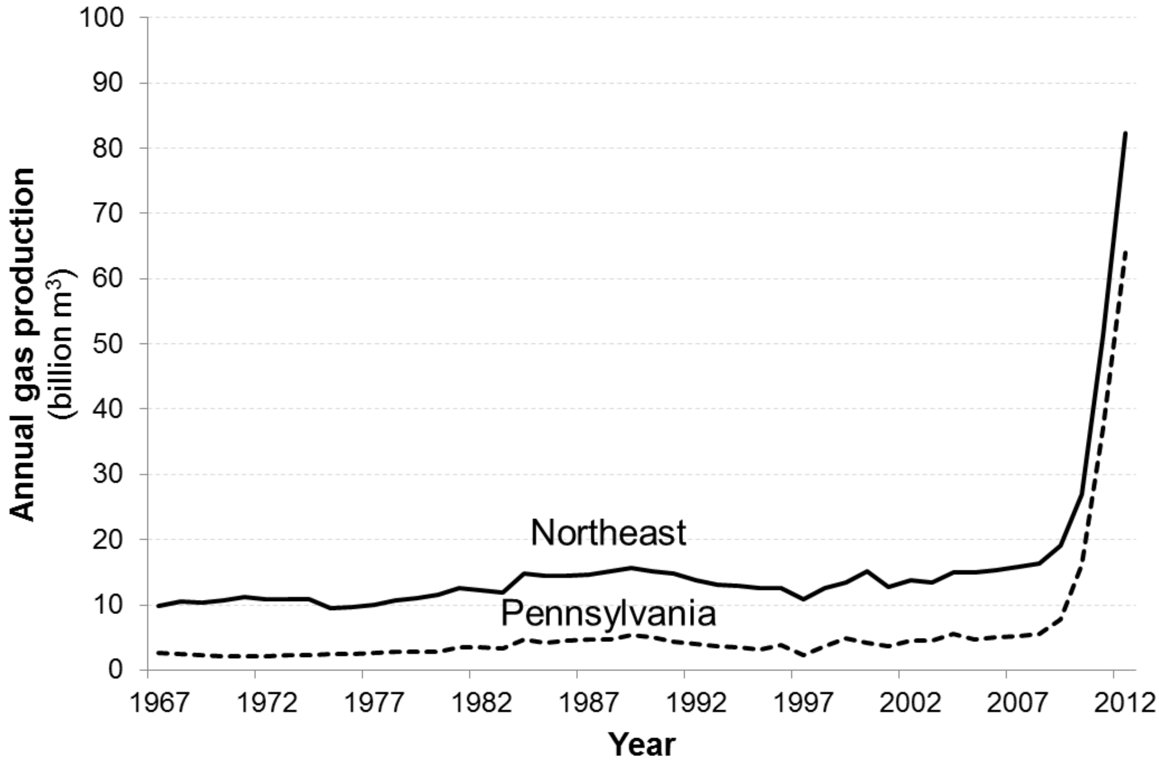


Figure 1: The sum of gross gas production from Maryland, New York, Ohio, Pennsylvania and West Virginia (1967-2012) (*4-8*).

This chapter will provide some context of potential challenges associated with this development. The thesis will then focus on evaluation of three potential environmental concerns associated with shale development in Pennsylvania

Potential health and environmental risks

Discussions of the sometimes unintended and sometimes unavoidable costs of developing the unconventional gas resources of Appalachia provide the necessary background for this thesis. These are the negative impacts or risks to the land, water, and air that might occur and those that will occur in order to extract methane gas and liquid hydrocarbons from the Marcellus Shale and other unconventional reservoirs. What follows is a summary of potential impacts and risks that have been associated with shale gas development in Appalachia.

The establishment of well pads, pipeline right-of-ways, access roads, and other infrastructure required for developing and producing shale gas involves clearing and grading a minimum of around 1 hectare for the well pad but the total disturbance associated with each well pad (including pipelines and access roads) may sum to 3.6 hectares or more if "edge effects" are considered (*9-12*). Around 38-54% of well pads have been established in forest land (*11*), where known problems are forest fragmentation and habitat loss, particularly from pipelines (*13, 14*). With forest fragmentation, species of interior forest ecosystems will decline, while those that live in high grass and the forest's edges (e.g., white-tail deer) will benefit (*15-17*). Clearing and grading land also creates opportunities for environmental damage from topsoil loss and stream siltation because of Appalachia's topography and climate (*10, 13, 18*). Minimizing these costs requires effective storm water and erosion controls.

Contamination of drinking water aquifers is a risk from well drilling, casing and cementing, and hydraulic fracturing operations (*19, 20*). The quality of the bond formed by the cement to the wellbore and to the casing is a significant risk factor for the migration of fluids in the wellbore to underground sources of drinking water (*21*). Updates to well construction and casing standards in Ohio (*22*), Pennsylvania (*23*), and West Virginia (*24*) require the use of modern methods and materials. However, protection of drinking water aquifers requires keeping them isolated from brine- and hydrocarbon-bearing formations over the lifetime of a well, which requires not only successful installation, but also diligent monitoring and maintenance (*21*). Questions remain about the causes of elevated methane in private drinking water wells close to development. This association has been reported in studies conducted by Duke University in

2011 and 2013, which included 60 and 141 water wells, respectively (*25, 26*). A report conducted in 2012 by The Pennsylvania State University, reported no association in 233 water wells (*27*). A study by GSI Environmental and Cabot Oil & Gas published in 2013 found that methane to be common in pre-drilling tests of 1,701 private water wells, and thus finding other explanations for the occurrence of methane (*28*).

Additional concerns for drinking water aquifers center on the possibility that hydraulic fracturing in the vicinity of existing hydraulic connections (i.e., natural fractures in the overlying geologic strata or an existing oil/gas well) may provide additional pathways for contamination. Warner *et al*. (2013) suggested the existence of conductive pathways between deep formations and drinking water aquifers from relationships in the geochemical data from 426 shallow water wells in northeastern Pennsylvania and 83 northern Appalachian brine samples. In a letter response, Engelder asserted that capillary tension and subsequent imbibition of liquids to the shale made hydraulic fracturing an unlikely source for contamination on “human time scales” (*29*). Warner *et al.* presented contrasting data in their reply to Engelder and suggest this remain an open question (*30*). In southwestern Pennsylvania, the National Energy Technology Laboratory (part of the Department of Energy) mixed perfluorocarbon tracers with the hydraulic fracturing fluid being injected into the Marcellus Shale. In eight months of observation, the produced gas from two conventional gas wells (producing from reservoirs above the Marcellus) showed none of the tracers (*31*). Study limitations are that only one site was examined and the tracers were not injected in the beginning hydraulic fracturing stages.

There is also potential for contamination of drinking water supplies when hydraulic fracturing interacts with existing wellbores, which has already occurred on multiple occasions (*32, 33*). These interactions amount to a short-circuiting of the “frac” barriers, which are the overlying geologic strata that limit the propagation of fractures during the hydraulic fracturing process. With hundreds of thousands of wells in Pennsylvania, most of which are unknown in location and depth, the opportunities are abundant. Vertical separation between the horizontal wellbore and the bottom-hole of nearby conventional wells is a key risk factor (*21*). However, thousands of wells have been drilled to the Oriskany formation, which is below the Marcellus Shale (*34*). Worth noting is a trend towards hydraulic fracturing in shallower (non-Marcellus) formations, where the vertical separation to Pennsylvania's shallow conventional wells will be much less or zero (*35*).

For each well that is hydraulically-fractured, the production, handling, and disposal of wastewater will be a potential issue until a well is permanently plugged and abandoned (*36*). Though leaks and spills are unavoidable, steps can be taken to minimize the frequency of spills and their impact (*12, 13, 37, 38*). After two attempts, first at municipal treatment plants and later at industrial treatment facilities, we now know that the metal-rich radioactive brine generated from well completion and gas production cannot be safely discharged to rivers with only partial treatment (*18*, *39*-*43*). In Pennsylvania, new effluent standards for total dissolved solids (*44*) and voluntary restrictions accepted by the largest gas industry players (*45*) spurred the high rates of wastewater reuse (>90%) in the field today (*20*) and interest in advanced treatment technologies (*46*). This has been a positive development by reducing how much wastewater is generated and how much freshwater is consumed for hydraulic fracturing. Deep well injection of industry-generated waste can be a means for permanent geologic sequestration. However, recent earthquakes caused by an injection site in Ohio demonstrate the potential for geologic instability if injection locations and pumping rates are not carefully controlled (*47, 48*).

There are potential health and environmental risks associated with the generation and disposal of radioactive waste, particularly that which has been concentrated, known as technically-enhanced naturally occurring radioactive material. Radium can occur in elevated concentrations in drill cuttings, and is dissolved in produced water and in the sludge of metals that settle from it (*49-51*). Disposal of drill cuttings and sludge now accounts for 10% of all radiation alarms at Pennsylvania landfills (*52*), but for individual landfills the frequency can be much higher (*53*). The highest radium concentrations have been found in the dewatered sludge cakes generated by industrial water treatment facilities; in some cases at levels requiring U.S. Department of Transportation Hazardous Materials Regulations (*52*). Elevated radium was also found in the streambed downstream of a facility that accepted and only partially treated wastewater (*54*). Radioactive lead and polonium will also be present, usually as a film, on the interior surfaces of pipes, valves, and compressors, etc. used to move natural gas due to the decay of radon mixed with the gas (*55, 56*). The Pennsylvania Department of Environmental Protection is engaged in measurement of radioactivity generated throughout the gas production and transmission processes (*57*).

Air pollutants such as fine particulate matter, sulfur oxides, nitrous oxides, carbon dioxide, and volatile organic compounds come from fossil fuel combustion, including the engines of vehicles, generators, pumps, compressors used by the industry. A majority of the emissions come from ongoing gas production and compression activities, which are expected to be long-term sources (*58*). Emissions of volatile organic compounds and nitrous oxides lead to the formation of ozone, which is a hazard to human health. Roy *et al*.(2013) projected that Marcellus Shale development might be responsible for 12% of these ozone-forming emissions in 2020, but this did not account for likely changes to the emissions in other sectors where the use of natural gas lowers these emissions i.e. coal power generation (*59*). A positive trend in the industry is the use natural gas as the combustion fuel in place of diesel (*60*). Volatile organic compounds, hazardous air pollutants, and methane emissions during well completion are the target of new EPA rules for production wells that require “reduced emissions completions” beginning in 2015 (*61, 62*). Flaring is allowed in the interim. Additional emissions sources for volatile organic compounds during production are the processes to separate methane from produced water and hydrocarbon liquids (condensate), and the off-gas from the storage of these fluids (*63*). Hazardous air pollutants, such as benzene, are also present in the off-gas. Greenhouse gas emissions will also result from the production, processing, transport, and consumption of natural gas (*64*). Because the climate implications could be substantial, the quantification (and uncertainty) of greenhouse gas emissions associated with shale gas development an important subject area (*65-68*). Recent results from an ongoing study of methane emissions in the natural gas industry measured upstream emissions much lower than previously cited estimates (*69*).

Focus of this thesis

The efforts just described have improved our understanding of the most salient health and environmental risks associated with shale gas development in Appalachia. There have also been beneficial changes to the regulatory framework, and new financial and informational resources have been made available to state agencies and to the public. The analyses that comprise the body of this thesis address potential risks that have not yet been observed at a large scale but that could manifest in the future. These are the lung cancer risks due to radon in natural gas, water resources risks from surface water withdrawals, and the risks of underfunding future reclamation liabilities.

In the first analysis, the question of whether radon in natural gas will pose a health risk is raised. Though trace levels of radon are common in natural gas, the emergence of shale gas in Appalachia has changed underlying assumptions upon which past assessments this risk were based. Concerns that radioactive gas will be delivered to homes in dangerous quantities have contributed to protests and social media efforts against the construction of new pipelines. In the last year, three advocatory reports have been published on the radiation risks from Marcellus gas to consumers in New York, but each leaves many questions unanswered. A potential future scenario where locally-produced shale gas dominates the Northeast gas market is used to assess the lung cancer risk associated with unvented cooking and space heating.

The second analysis investigates the adequacy of regulatory program covering water withdrawals for unconventional gas development in the Upper Ohio River Basin of Pennsylvania. The industry extracts large amounts of water from local rivers and streams to support drilling and hydraulic fracturing. Reports that streams were being "pumped dry" by gas companies led to concerns that drinking water quality and aquatic ecosystems were not adequately protected (*70*). In 2008, the Pennsylvania Department of Environmental Protection implemented a program to manage this industry's withdrawals in western Pennsylvania. In this thesis the methods for allocating water withdrawals being used in the Upper Ohio River Basin are contrasted to methods advocated by other regulatory agencies in the region. The objective is to examine the adequacy of regulatory protections for water resources and aquatic ecosystems, given the state of the hydrologic data upon which they are based.

The third analysis examines the potential for a future orphan well problem, and the health and environmental risks that might result. Pennsylvania's financial assurance (well bonding) program for the reclamation of oil and gas wells, was enacted in 1984 and updated in 2012. The program is designed to incentivize regulatory compliance by requiring a bond (or surety, cash, proof of credit, etc.) from the well's owners that can only be released after a well has been satisfactorily decommissioned, referred to as "plugging and abandonment" by the industry. The economics of Marcellus Shale gas production and issues with the current program, such as regular non-compliance in the conventional gas industry, are examined. Alternative approaches that would enhance environmental protections and minimize the financial exposure of taxpayers to socialized environmental costs are advanced.

Chapter 2: Locally-supplied gas for the Northeast: Is radon a concern?

Introduction

Most natural gas has some level of radioactivity from the radon that exists naturally in the subsurface. Several authors have analyzed the health risks of radon from the use of unvented gas appliances in U.S. homes (*71-77*). Nearly all of the available information on natural gas radon concentrations comes from conventional gas reservoirs in southern and western states. Though it is not known if the radon concentration of natural gas produced from shale formations is higher than what has been measured in conventional sources, the proximity of produced Marcellus Shale gas to Northeast U.S. consumers means there will be less time for radioactive decay to occur in transit. For this assessment, the radon-related health risks for a scenario when nearly all of the natural gas consumed by the Northeast U.S. will be from local supplies is analyzed.

Radon is a noble gas. It cannot be destroyed by combustion and it does not chemically react. Radon-222 is also radioactive and when it decays, its radioactive progeny, lead-214 and polonium-218, can deposit on epithelial cells of the lung and produce a DNA-damaging alpha radiation that is associated with the development of lung cancer (*78*). The International Agency for Research on Cancer classified radon as a human carcinogen in 1988 (*79*). Furthermore, it has been established that lung cancer risk is in constant proportion to the dose (a linear dose-response model), so doubling the dose doubles the risk, and so on (*78, 80, 81*). Other confounding factors to consider include gender and lifestyle variables, particularly cigarette smoking. The linear dose-response model for radon assumes no low threshold, meaning that there is no safe level of exposure. The U.S. Environmental Protection Agency (EPA) recommends mitigation if radon levels are higher than 148 Bq/m^3 (4 pCi/L) in indoor air, which is associated with a 7 in 1,000 (7×10^{-3}) lifetime lung cancer risk (*82*). The outdoors, 14.8 Bq/m^3 (0.4 pCi/L), and indoors, 48.1 Bq/m^3 (1.3 pCi/L) radon concentration averages would therefore be associated with a 7×10^{-4} and 2×10^{-3} lifetime lung cancer risk, respectively.

Whether or not people use natural gas, they are exposed to radon at varying levels every day. Naturally occurring radioactive materials, such as radon, are present in the environment. Radon is constantly emanating from rocks and soils that contain the parent radionuclides. Most of the population receives their highest daily radiation dose from radon, and these radon-related doses are usually highest in homes. The major routes of radon entry to homes are cracks and joints in home basements or foundations. Other potential and often much smaller sources are building materials and well water (*83, 84*). Reducing background exposure and entry to homes is a national public health priority as radon is the second leading cause of lung cancer death after smoking (*78, 80*).

Background

<u>Radon exposure and lung cancer</u>

Initial understanding about the health risks from exposure to radon came from studying cohorts of people who worked in underground mines and, by the nature of their work, were exposed to radon levels well above background levels. The National Research Council and the U.S. EPA relied on data from 11 mining cohorts and laboratory animal studies (*78, 80*). These studies established radon as a risk factor at exposure levels more than 10 times typical residential exposures (*85*). Due to the lack of epidemiological evidence showing harm at typical residential exposures, the theory of beneficial radon exposure (radiation hormesis) coexisted in epidemiological discourse (*86, 87*). Nonrespiratory mortality risk due to radon have been investigated and determined to be insignificant (*88, 89*).

In the last 10 years there have been numerous studies of residential exposure to radon and lung cancer risk. Krewski *et al.* combined data from seven case-control studies in North America and estimated a lung cancer risk of 11% (95% CI, 0-26%) per 100 Bq/m^3. The excess relative risk was 21% (95% CI, 3-52%) for a subset of this population with well-defined exposure data (*90, 91*). Turner *et al.* (2011) used county-level radon data from the EPA (*92*) to study a cohort of over 800,000 people and 3,493 lung cancer deaths. A significant ($p = 0.02$) linear trend in lung cancer risk was found, indicating that exposure per 100 Bq/m^3 leads to a 15% (95% CI, 1-31%) lung cancer risk nationwide. Turner *et al.* re-examined the data by geographic area, and for the Northeast (the only region with a significant result), the lung cancer hazard ratio was 1.31 (95% CI, 1.12-1.53) per 100 Bq/m^3 exposure (*81*). (A hazard ratio is similar to relative risk, but hazard ratios represent the risk for a defined time period and relative risk is cumulative over a whole study. They both are ratios of disease occurrence in an exposed and a control population.)

Origins of radon in natural gas

Burial of organic matter, plus heat, pressure, and time describe the process by which methane and other hydrocarbons are produced (*56*). The Marcellus Shale has marine origins. The natural gas being produced today is derived from organic material deposited on the floor of an epicontinental sea between the Acadian Mountains and the Cincinnati Arch during the Devonian geologic period around 400 million years ago (*93*). Adsorption to organic material settling to the seafloor is the primary removal process for uranium in seawater (*94, 95*). Globally, seawater sediments are the largest sink for uranium in the environment (*96*). The amount of uranium delivered to the ocean, sedimentation rate and organic matter production and preservation vary regionally (*97*). Favorable conditions for uranium enrichment existed at the time Marcellus Shale was deposited (*98*). The ^{238}U concentration in the Marcellus Shale ranges from 10 to 100 parts per million (ppm) (*50, 74*), in contrast to the global average concentration of uranium in shale of around 3.7 ppm (*99*).

The close association of uranium and organic matter means that methane-filled pore spaces in the Marcellus Shale also contain uranium progeny, including radon (*100-102*). Therefore, producing gas also means producing radon. Radon's longest-lived isotope, ^{222}Rn (half-life 3.8 days), occurs after ^{226}Ra in the ^{238}U decay series. ^{226}Ra is abundant in the shale matrix, and is also found dissolved in the produced water of a hydraulically-fractured well (*51*). If ^{226}Ra is in solution, emanating ^{222}Rn will partition to the gas phase (*103*). ^{222}Rn emanating from ^{226}Ra in the shale matrix could also enter the produced gas stream (*104-107*).

Measurements of radon in natural gas

Radon concentrations in natural gas produced from approximately 2,100 conventional gas wells in western and southern U.S. states across nine studies between 1952 and 1973 averaged concentration of 1,369 Bq/m^3 (37 pCi/L) with a range of 7 to 54,000 Bq/m^3 (*71*). Measurements of radon in natural gas produced from upper Devonian shale (non-Marcellus) were conducted for Eastern Gas Shale Project (EGSP) in 1980 by the Department of Energy (*108*). The eight producing wells near the border of West Virginia and Kentucky that were sampled had a production-weighted average radon concentration of 5,587 Bq/m^3 with a range from 962 to 9,139 Bq/m^3.

Rowan and Kraemer analyzed gas from 19 wells producing Devonian age gas in southwestern Pennsylvania; 10 of these were recent Marcellus Shale wells (*103*). The average radon concentration was 1,282 Bq/m^3 with a range from 37 to 2,923 Bq/m^3. For the subset of Marcellus Shale wells, the average radon concentration was 1,145 Bq/m^3, but little can be said about the representativeness of these data for the >7,000 wells producing gas from the Marcellus Shale.

Wellhead radon concentration is only part of the story, as radon decays in transit from well to consumer. Radon concentrations in transmission and distribution systems serving Chicago, Denver, New York City, and the Southwest U.S. were studied in 1973 (*72*). A total of 48 gas samples, some duplicates, were collected and the radon concentration ranged from 18.5 to 4,400 Bq/m^3. Radon activity was highest near Denver and lowest in New York City, where the highest radon concentration did not exceed 141 Bq/m^3 across 18 samples. In 2012, the radon concentration of natural gas at eight locations leading to and on Spectra Energy's Texas Eastern transmission line was measured (*77*). The Texas Eastern line runs through Pennsylvania to New Jersey where it connects with the Algonquin transmission line that carries gas to Massachusetts. The highest radon concentration, 1,628 Bq/m^3, was reported in southwestern Pennsylvania for gas entering the transmission line and the lowest, 629 Bq/m^3, was reported for a mixed supply of gas in the main transmission line in northern New Jersey.

The most detailed studies of radon in transmission and distribution systems were conducted abroad. This included measurements to characterize the radon concentration in natural gas produced from North Seas basins (*109, 110*). Natural gas samples were taken from onshore transmission lines and radon concentrations differed across basins, from <50 Bq/m^3 to 600 Bq/m^3. Wojcik performed daily measurements of radon activity (average 235 Bq/m^3) in a natural gas distribution system in Poland and reported significant daily and seasonal variations, varying by as much as a factor of 2.4 (*111*). The natural gas radon concentration was measured at various points between production and consumption in British Columbia, Canada. The radon levels measured in 15 gathering systems covering an area <40,000 km^2 varied by wide margins (range 7-921 Bq/m^3) (*55*).

<u>Exposure to radon from natural gas</u>

Any radon present in natural gas will also be present in its combustion gases. Unvented heating and cooking appliances release combustion gases into the living space. Natural gas ranges may be equipped with overhead mechanical systems that provide ventilation and/or filtration, but capture efficiency may be low (*112*). Even if exhaust gas is captured, systems that provide exterior ventilation are less common than those that simply recirculate the combustion gas through an activated carbon filter (to remove odors, smoke, grease, and steam) and discharge to the home (*113*). Some radon may be absorbed onto these filters, but research in this area is very limited (*114*).

Vent-free space heaters (e.g., gas hearths, gas logs, etc.) come in many shapes and sizes, but all are designed to keep the exhaust gases in the living space to provide supplemental or zonal heating (*115*). A small and decreasing number of homes may also have gas appliances with pilot lights that continually burn and do not vent to the atmosphere. Use of gas ranges for space heating has also been documented (*116-118*).

Johnson and Barton *et al.* estimated potential population doses from unvented cooking and heating using U.S. wellhead and distribution measurements in 1973, respectively (*71, 72*). Both concluded that the potential risk from exposure was small compared to background. Johnson also calculated the cost associated with mitigating the risk, which he assumed would be through additional above-ground gas storage. The cost per life saved he estimated was more than $100 million (*71*). Gogolak repeated these calculations in 1980 using radon concentration data from Devonian shale wells and estimated that radon concentrations in natural gas would need to be higher than 37,000 Bq/m^3 for annual average exposure >12 Bq/m^3 (*74*).

Three non-peer reviewed reports have been published in the last year on the potential health effects to people who cook with natural gas in New York. Resnikoff used a theoretical model to estimate a range of wellhead radon concentrations of 155-95,000 Bq/m^3 and projected <20 to >30,000 lung cancer deaths in New York City over a 30 year period (*75*). In response, Anspaugh (*77*) and Krewski (*76*), published tandem reports in 2012 in support of Spectra Energy's plans for constructing a gas a pipeline to ConEdison customers in New York City (*119*). Anspaugh computed a 30-year lung cancer risk of 10^{-5} using the same dilution factors as Resnikoff, but using the natural gas radon concentration of 629 Bq/m^3 measured on Spectra Energy's transmission pipeline. This concentration was also used by Krewski to calculate a lifetime (70-yr) risk of 1.96×10^{-5} for New York residents. A sensitivity analysis was performed that included radon concentration, size of residence, air exchange rate (AER), and occupancy fraction (time spent at home). The highest natural gas radon concentration examined was 740 Bq/m^3 and the "plausible maximal exposure" calculated from it was associated with a lifetime lung cancer risk of 8.95×10^{-5}. None of the three reports considered exposure from unvented space heating.

Assessment goals

Recent studies in this area present limited and conflicting views of the health risk associated with radon in natural gas. Resnikoff's report provided insufficient documentation of the methodology used to estimate the high wellhead radon concentrations analyzed, while the Anspaugh and Krewski reports were narrowly scoped and the radon concentration data they use to calculate risk should not be considered representative of future Northeast gas supplies due to ongoing infrastructure changes and growing local supply. The goal of this study is to assess the lung cancer risk due to unvented cooking and space heating with locally-supplied natural gas in Northeast U.S. homes.

There are four primary tasks:

1) Establish estimates for the average natural gas radon concentration at the burner-tip of Northeast U.S. homes from information related to the radioactivity of locally-produced gas, supply mixing, and transit time.
2) Model population-weighted radon exposure for unvented cooking and space heating based on realistic and, to the extent possible, representative appliance use and settings in the Northeast.
3) Assess the lung cancer risk and public health implications from radon in natural gas.
4) Examine model sensitivity to uncertain parameters, and perform an analysis for subsets of the population that might face elevated risk.

Radon in the Northeast residential gas supply

The system of pipes, processing facilities, compressor stations, etc. used to deliver natural gas to Northeast consumers is complex and changing. For the producers and shippers of natural gas, keeping Marcellus Shale production local has favorable economics; however, reorienting the natural gas system to make this a reality will be a decades-long process as some of the largest infrastructure projects are still in the permitting phase (*120*, *121*). ICF International estimates that almost 89% of New York City's gas supply will originate from the Marcellus Shale by 2030 (*120*). It is this future gas supply, rather than current conditions, that is relevant to this study. Below are found the assumptions used to represent this scenario in the subsequent risk analysis.

Relevant radon concentration data

A bounding analysis was performed to understand maximum and minimum population-level excess exposures and lung cancer risks. As a lower bound for the natural gas radon concentration, 884 Bq/m^3 was selected, which is the lowest radon concentration reported from six locations where gas was being injected into Spectra Energy's transmission line (*77*), Table 1.

Table 1: Natural gas radon concentration data for six injection points to the Texas Eastern transmission system (*77*).

Location	Description[1]	Date	Rn conc. (Bq/m^3)
Chambersburg, PA	Dry, unprocessed	6/27/2012	1,021
Chambersburg, PA	Dry, unprocessed	6/27/2012	884
Holbrook, PA	Dry, processed	7/1/2012	1,217
Fort Beeler, WV	Dry, processed	7/1/2012	1,447
Holbrook, PA	Dry, processed	7/2/2012	969
Waynesburg, PA	Dry, unprocessed	7/2/2012	1,632

[1] Processed gas has been through a thermal separation process that can affect the natural gas radon concentration. "Dry" gas does not contain large amounts of heavier hydrocarbons (e.g., propane, butane, ethane) (*73*).

The Spectra Energy samples were taken from locations where locally-produced gas is mixed (reducing the effect of well-to-well variability), but likely had not yet been mixed with non-local supplies. A shortcoming of these data is the limited geographical coverage of the sampling locations.

A radon concentration of 4,440 Bq/m^3 was selected as the upper bound for the average natural gas radon concentration input to the transmission system. This concentration was the highest recorded value from the 1973 study of natural gas radon concentrations in U.S. transmission and distribution systems (*72*). The sampled gas stream originated from production fields in the Texas panhandle, west Oklahoma, and west Kansas and is higher than any measurement currently in the public record of radon in Marcellus gas.

Supply mixing and radioactive decay

The mixing of locally-produced gas with low-radon supplies (e.g., stored gas) and radioactive decay during transit lower the radon concentration in the natural gas delivered to homes relative to concentrations at the compressor station. Figure 2 compares average monthly consumption (2002-2011) (*122*) with the most recent estimate for Marcellus Shale production in Pennsylvania (*123*). Annual production is fast-approaching the average Northeast natural gas consumption, around 48 billion m^3 (1.7 trillion ft^3), but the months with highest consumption (January, February, March, and December) might continue to exceed local production levels. Two alternative scenarios to make up the difference in supply and demand in Marcellus dominant future scenario are (1) assume that local production matches monthly consumption, and (2) assume that natural gas with zero radon content is drawn from storage (or imported) and mixed with local Marcellus Shale production, reducing the average natural gas radon concentration in these winter months.

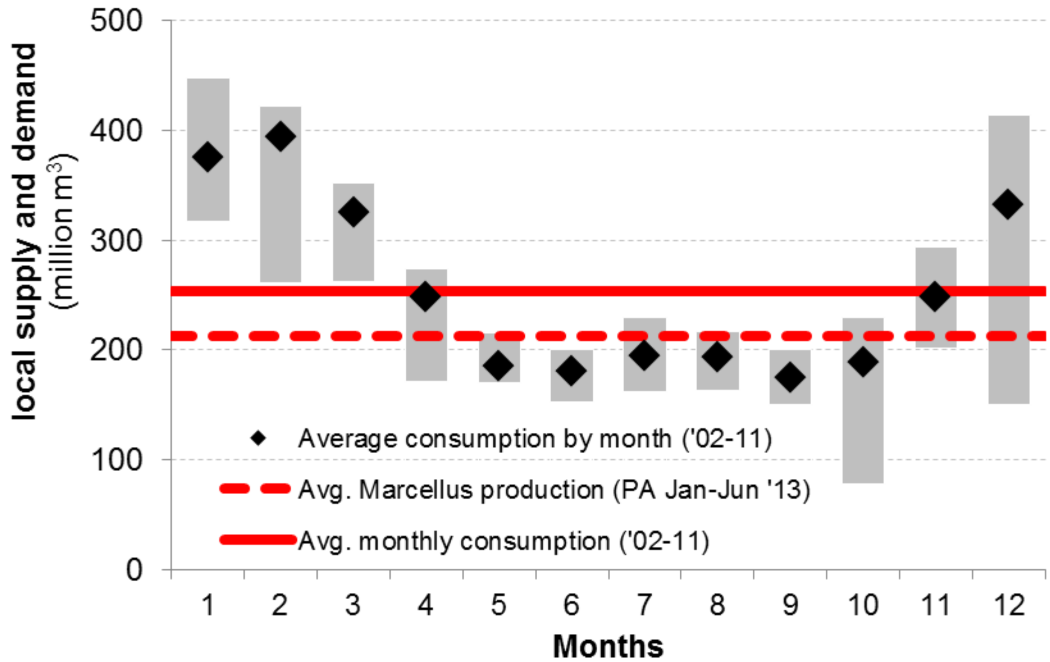


Figure 2: Northeast average, minimum, and maximum monthly consumption between 2002 and 2011. The solid line represents average annual consumption in the Northeast (*122*). The dashed line is the average Marcellus Shale production in Pennsylvania from January to June 2013 (dashed line) (*123*).

The time elapsed between production and consumption determines how much radioactive decay occurs in transit. Because pipelines are operated within narrow pressure and temperature ranges, the velocity of the gas (and thus the transit time) will be proportional to the throughput (*110, 111, 124*), which is equal to the consumption rate. Figure 2 shows that average monthly consumption in the winter can be twice the rate in summer. For February, the month with the largest average consumption, a range for pipeline transit time of zero hours (worst case) to 2 days was chosen, based on reported transmission velocities of 16 to 32 km/hr (*55, 74, 125*). Ranges for transit time were computed for all other months assuming proportionality to demand, so transit time in summer months is roughly twice that of winter months, Table 2. Decay is estimated from the half-life of radon-222, which is 3.8 days.

Table 2: Assumed travel times (days) by month for gas entering the transmission pipelines until use in the home.

	Modeled days between production and consumption											
Month	1	2	3	4	5	6	7	8	9	10	11	12
Lower bound	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Upper bound	2.1	2.0	2.4	3.2	4.2	4.4	4.0	4.1	4.5	4.2	3.2	2.4

Model for average annual radon exposure

Exposure is the integral of indoor air concentration over time spent indoors. To estimate the average annual radon exposure from unvented cooking and space heating, the average indoor radon concentration was computed from the mass-balance (Equation 1):

$$C_{ia} = \frac{C_{gas} Q_{UV}}{V \cdot AER} \quad (1)$$

where C_{ia} is the indoor air radon concentration (Bq/m^3), C_{gas} is the natural gas radon concentration (Bq/m^3), Q_{UV} is the unvented gas use rate (m^3/hr), V is the volume of all freely-connected living spaces in the home (m^3), and AER is the air exchange rate ($1/hr$) (*126*).

Equation 1 represents uniform and instantaneous mixing of radon in the freely-connected (i.e., a single compartment) living space. In reality, radon concentration (and exposure) will be higher closer to the source and lower in areas to which the flow of air is restricted, but, for the purpose of calculating average exposures in a connected space and across the population, this assumption is adequate (*126-129*).

The following subsections detail the parameterization of the exposure model from data collected in the Residential Energy Consumption Survey (RECS), which included a total of 2,066 mobile homes, single family (attached / detached) homes, and apartments in the Northeast U.S. RECS collects data on appliances and their use, home characteristics, and energy consumption (obtained from utilities). A representative sample of homes was selected by RECS through a statistical process and the results for Massachusetts, New Jersey, New York, and Pennsylvania were individually representative, while remaining Northeast states (Connecticut, Maine, New Hampshire, Rhode Island, and Vermont) were grouped in a single domain. Each of the surveyed homes was assigned a weight based on the number of non-survey homes it represents (*130*).

RECS also calculated a non-linear multivariate regression of residential energy end-uses. For natural gas, the RECS end-use model is based on consumption information and survey data for gas appliances and usage. The 2009 consumption data were separated into space heating (SPH), water heating (WTH), and *other* components, Equation 2:

$$Q_{Total,2009} = Q_{SPH} + Q_{WTH} + Q_{Other} \qquad (2)$$

where the main components of Q_{other} in Equation 2 include natural gas used for cooking, clothes drying, and/or pool or hot tub heating.

Unvented cooking and heating

The Q_{UV} term in Equation 1 is the quantity of gas consumed in a home that is not directly vented to the outside. For the exposure model this is the annual quantity of natural gas used for unvented cooking and heating.

Cooking

How much radon enters the home due to cooking with a natural gas range is estimated in this section. Natural gas cooking was reported by 47% of RECS housing units (130). Summary data for cooking are included in Table 3 and Table 4.

Table 3: The fraction of homes that cook with natural gas by RECS survey domains. "Gas-consuming" housing units are all homes that reported using natural gas in 2009.

	CT, ME, NH, RI, VT	MA	NJ	NY	PA	Northeast
# housing units (surveyed) that cook with NG	87	213	508	149	87	1044
Housing units (weighted) that cook with NG (1000's)	581	1060	4347	2279	1457	9723
% of "gas-consuming" housing units	51%	62%	76%	80%	62%	71%
% of all housing units	19%	43%	60%	72%	30%	47%

Table 4: Types of homes that cook with natural gas by RECS housing unit type. Single-family homes are considered detached when they do not share a common wall with another home.

RECS housing unit	# housing units (surveyed) that cook with NG	Housing units (weighted) that cook with NG (1000's)	% of "gas-consuming" housing units	% of all housing units
Mobile Home	6	87	86%	17%
Single-Family Detached	445	4240	69%	39%
Single-Family Attached	125	974	74%	54%
Apt. Building 2 - 4 Units	202	1764	70%	56%
Apt. Building 5+ Units	266	2658	72%	60%

The volume of gas consumed annually for cooking was estimated two different ways. Estimate A was based on reported frequencies for natural gas oven use and for *hot meals* cooked in RECS. For both categories respondents chose from a range of 3+ per day to less than once a week (conversion of qualitative frequencies to "meals per day" is documented in Appendix Assumptions for cooking estimate A). Since oven use could have been interpreted to include stovetop burners, and *hot meals* could have been interpreted to include microwaving, grilling, etc. (*131*), the maximum "meals per day" was chosen and 10,000 Btu for each meal was assumed. Gas ovens (and broilers) typically consume 10,000-20,000 Btu/hr while individual stovetop burners consume 4,000-12,000 Btu/hr. Natural gas volume was determined from the energy content of natural gas assumed by RECS: 36 Btu/L (1,025 Btu/ft^3).

Estimate B for natural gas cooking consumption was derived from Q_{other}, an output of the RECS end-use model intended to capture all *other* uses of natural gas besides water and space heating uses. In 59% of the homes all of Q_{other} was attributed to cooking because the only *other* use could have been a natural gas oven and/or stove based on the set of appliances recorded in the RECS survey. About 3% of homes reported heating pools and hot tubs with natural gas, which consume a lot of energy when used, but since information about their use was not available, cooking consumption for these homes (35 total) was set to the estimates from A. For 30% of the homes Q_{other} could only be attributed to cooking and clothes drying, so natural gas consumption for clothes drying was estimated by a similar approach as in A (Appendix Assumptions for cooking estimate B), and subtracted it from Q_{other} to arrive at estimate B for cooking. Out of 309 homes with both appliances, the survey-based estimate for dry use was greater than Q_{other} in 46 cases and the estimates from A were used instead.

An upper limit for cooking consumption of 25,000 Btu per person per day was established (Appendix Assumptions for heating estimate B). The cooking consumption limit for estimate B effected 56 (5%) of the homes that cook with gas. Figure 3 compares the distribution of daily cooking hours, incorporating each home's weight and occupants, normalized to 10,000 Btu/hr, for estimates A and B. Estimate B predicts more cooking in the population.

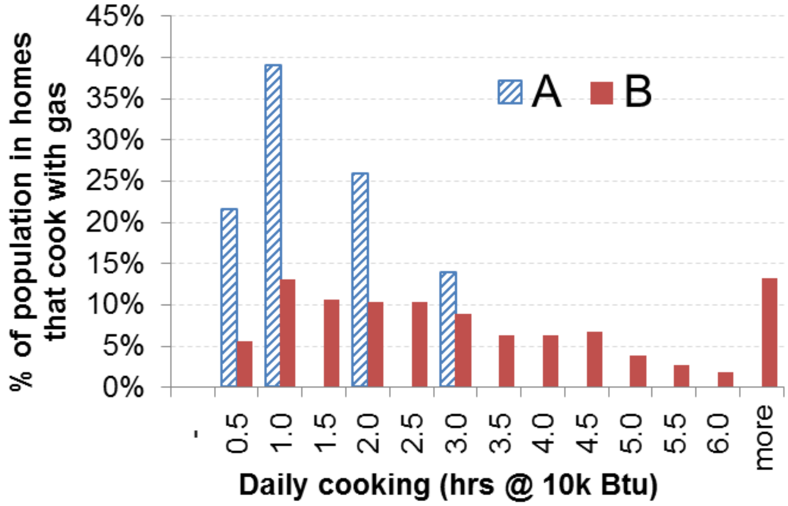


Figure 3: Distribution of cooking times comparing cooking estimates A and B, given as the percent of the population living in homes normalized to daily cooking hours at 10,000 Btu.

Unvented heating

A small fraction of Northeast homes use gas ranges or *vent-free* (room-vented) gas appliances for heating. RECS data for both are given in Table 5. Note that RECS does not distinguish vented gas room heaters from unvented versions, so Table 5 includes both.

Table 5: RECS weighted housing units (1,000's) for primary and secondary heating by unvented gas appliances. The number of surveyed homes is given in parenthesis. The Room heater category may include vented appliances, but all Fireplaces are vent-free ("flueless").

	Primary	**Secondary**				
RECS housing unit	*Cooking stove*	*Room heater (all)*	*Cooking stove*	*Room heater (all)*	*Fireplace (flueless)*	**Total**
Mobile Home	-	-	-	-	-	**-**
Single-Family Detached	-	60 (6)	-	75 (9)	127 (8)	**261**
Single-Family Attached	-	18 (3)	3 (1)	4 (1)	-	**25**
Apt. Building 2 - 4 Units	5 (1)	47 (9)	12 (1)	-	-	**64**
Apt. Building 5+ Units	-	53 (7)	35 (4)	-	26 (2)	**114**
Housing units (weighted) that cook with NG (1000's)	5	177	50	79	153	**465**
% of all housing units	0.03%	0.9%	0.2%	0.4%	0.7%	**2.2%**

The data on unvented space heating are insufficient to be used as representative of the Northeast. Compared to the population-level consumption estimate for natural gas cooking, it cannot be assumed that the homes in Table 5 and related survey data are a valid representation of where and how unvented heating occurs.

Instead of analyzing the small number of homes in Table 5, the use of a single unvented gas appliance for heating was modeled in 1,074 RECS apartments and single-family housing units that used natural gas for >95% of the total heating load, but do not currently use natural gas for secondary heating. The assumption here is that all homes that heat with gas are equally likely to heat with unvented gas appliances, though local laws and building codes (*132, 133*), weather, and economic factors play a role (*118*). The 1,074 RECS apartments and single-family housing units that are used in this model represent over 10 million Northeast U.S. homes.

The output of a "generic" unvented heating appliance (btu/hr) was calculated from the volume of the space in which the heater will be operated. Guidelines published for New York by the *vent-free* industry recommend sizing vent-free heaters to approximately 140 $\frac{Btu}{hr \cdot m^3}$ in "average" construction homes (*134*). The total volume of the heated space (m^3) was estimated by multiplying floor area of the heated space (from RECS) by 2.5 m (3.5 m if high/cathedral ceilings were indicated). The volume of the space where the heater will be operated was assumed to be 1/5 of the total heated space (see the Hearth, Patio & Barbecue Association's "Fuel Efficiency Calculator for Zone Heating"). For 15 housing units the output was capped at 40,000 Btu/hr because larger vent-free heaters are not allowed in residential settings (*133*). The distribution of modeled outputs relative to the population is shown in Figure 4.

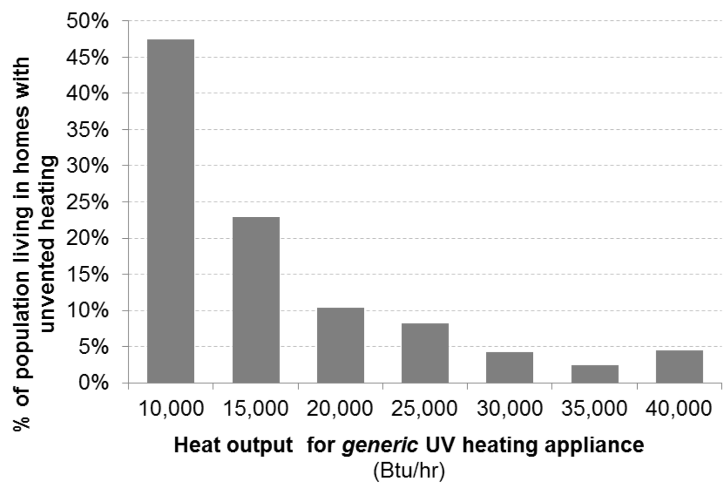


Figure 4: Distribution of the unvented heating population as a function of modeled heat output for a "generic" unvented heating appliance. For 78% of people in the Northeast the estimated output is less than 20,000 Btu/hr. The average outputs for single-family homes and apartments were 16,000 and 10,500 Btu/hr, respectively.

As before, gas consumption for unvented space heating was estimated two ways. Estimate A is intended to represent intermittent use of unvented heating over a 150 day heating season. This assumes the unvented heating appliance is used 52 days a year for 2.6 hours, which were the average values for gas fireplace use in a 2011 survey of U.S. homes (*115*).

Francisco and Gordon evaluated air quality in 30 Chicago-area homes (29 single-family and one condominium) that used *vent-free* gas fireplaces (*128*). For one home it was the sole heating source. Over a 3-4 day period, fourteen of the homes ran their fireplaces for at least 2 hours continuously and five were used for at least 4 hours continuously. Important findings are that unvented heating appliances were not being used according to manufacturers' guidelines and that locating an unvented heating appliance in the same room as the thermostat for a primary heating device leads to greater unvented appliance use (by preventing the primary heater from running).

Data related to unvented heating with cooking stoves are sparse. Fifty percent of respondents in a 1981 survey of 118 New York City apartments (90 rent-subsidized) reported using their natural gas ranges for heating, of which 46% reported "frequent" to "constant" use in the winter (*116*). Out of 79 homes surveyed in three Boston housing projects, 27% reported heating with a gas range, but usage information was not collected (*117*).

Estimate B is a model of supplemental or zonal heating using an unvented gas appliance. In general, supplemental heating involves targeting heat delivery to the most-used portion of the living space (e.g., family room). This allows for the output of the primary heating system to be reduced, and presumably lowers the heating bill. Marketing materials from the manufacturers of *vent-free* gas heaters claim a 10 to 40% savings in primary energy consumption (*135, 136*).

The supplemental heating energy use for estimate B was based on this claim of 40% savings of primary energy to simulate regular wintertime use of unvented space heating appliances. The annual Btu consumed by the "generic" unvented appliance for estimate B was determined by

Equation 3. This simplistic approach assumes that 1/5 of the heating energy saved, after adjusting for primary appliance efficiency, will need to be replaced by the "generic" unvented appliance:

$$Q_{UV} = \frac{\frac{1}{5}(40\%\ Q_{SPH} \cdot \eta_P)}{\eta_{UV}} \qquad (3)$$

where Q_{SPH} is the RECS end-use estimate for natural gas space heating in 2009 in Btu/yr, η_P is the efficiency of the primary natural gas heating appliance (AFUE 0.7-0.95 depending on equipment age, Appendix Assumptions for heating estimate B), and η_{UV} is the efficiency of the "generic" unvented appliance, assumed to be 99%.

In estimate B, the average runtime of a "generic" unvented heater would be 3.4 hours per day over a 150 day heating season, Figure 5. Average runtime over the heating season for estimate A is less than 1 hour per day, which is nearly equivalent to a 10% reduction in primary heating under Equation 3.

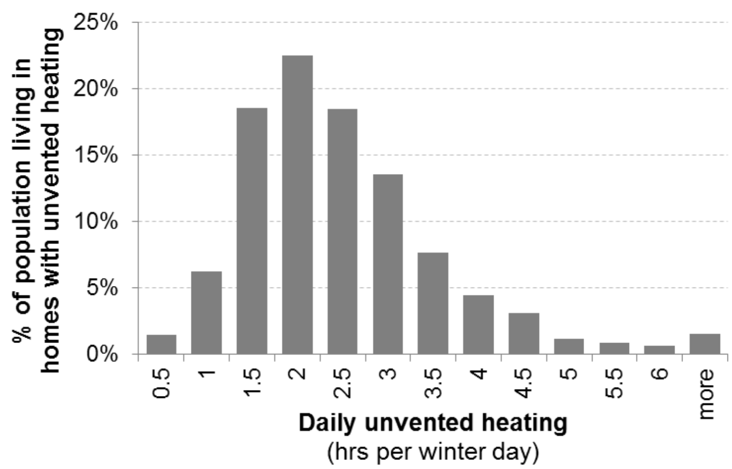


Figure 5: Distribution of the daily unvented heating (hours per winter day over a 150 day heating season) with the "generic" appliance for estimate B. As modeled, more than half of the population lives in homes with less than 2.5 hours of daily unvented heating.

Dilution volume and air exchange rate

The denominator in Equation 1 describes the dilution of radon in a freely-connected space. The V term is the volume of the space in which dilution occurs and was calculated from the product of total floor area (from RECS) and an average ceiling height of 2.5 m (3.5 m for high/cathedral ceilings). For unvented gas heating, the floor area of the heated space was used instead of the total.

Two cases for dilution volume were analyzed. The first assumed dilution over the whole volume of the freely-connected space. The second represented restricted air flow to some of the interior space in single-family homes because dilution of radon over the whole (or heated) house volume can be a poor assumption (*137*). The closure of interior doors and vertical temperature differences ("stack effect") in multi-story homes impede air movement (*138-140*). Therefore, in single family homes exposure from cooking was calculated as if dilution only occurred on a single level of the home (V divided by number of stories). For exposure from unvented heating, V was assumed to be 1/5 of the heated volume to simulate zonal heating. No changes to the V term were modeled for apartments.

The AER term in Equation 1 is the air exchange rate. It describes the rate at which air inside the home is replaced with air from outside of the home. AER depends on weather, home characteristics (e.g., leaky windows), and the behavior of occupants, all of which vary in time and space (*141-144*). The portion of AER due to infiltration, air leaking into and out of a home through cracks and gaps in its exterior, was included in the exposure model. The AER term did not include natural ventilation (e.g., opening a window) or mechanical ventilation (e.g., attic fan).

Empirical AER distributions developed by Murray and Burmaster (1995) in the exposure model were used (*145*). Separate empirical distributions exist for specific climate regions and seasons. The bounds chosen were the average annual AER $\pm$ 1 standard deviation for cooking, and the average winter (Dec-Feb) AER $\pm$ 1 standard deviation for unvented gas heating. Note that in order to use the empirical distributions, which are developed for climate regions, it was assumed that all RECS housing units in the New York State were in Murray and Burmaster "Region 2," while "Region 1" was assumed for all RECS housing units in the multi-state domain that included CT, MA, ME, NH, RI, and VT.

Population-weighted exposure

For each home in RECS with modeled gas usage (either unvented cooking or heating), Equation 1 was used to estimate the average indoor air radon concentration and exposure. From the previous sections, the uncertain variables are natural gas radon concentration, supply mixing, transit time, gas usage for unvented cooking and heating, and the air exchange rate. Table 6 summarizes the ranges that were assumed for each of the uncertain parameters.

Table 6: Summary of parameters used in the population-weighted exposure model.

Parameter	low estimate	high estimate	notes
Radon concentration (Bq/m^3)	884	4,440	Anspaugh, 2012; Barton *et al*., 1973
Transit time (days)	1	3	For baseline month, February
Supply mixing	Yes	No	Binary variable
Gas usage (M Btu/yr)			
Cooking	A	B	4.3-8.3% 2009 NE consumption
Heating	A	B	1.8-4.1% 2009 NE consumption
Dilution volume (m^3)			
Cooking	whole house	whole house / # stories	Only whole house used for apartments
Heating	whole house	1 / 5 house volume	Only whole house used for apartments
Air exchange rate (1/hr)	0.12-0.23	0.64-0.88	± 1 std. dev. from Murray and Burmaster, 1995
Occupancy fraction	100%	100%	Occupancy likely for cooking / space heating

While there is not enough information to do a Monte Carlo analysis, there is sufficient information to do a bounding analysis. In this bounding analysis, the effects of the uncertain parameters on the population-weighted exposure are examined. There are 64 (2^6) unique combinations of parameters in Table 6 for each gas usage model. Thus 64 unique estimates for exposure were obtained for each of the RECS homes with modeled gas usage (Respondents to survey for cooking: 1,044, heating: 1,074). Each of these estimates was then multiplied by the reported number of occupants in the housing unit and its home-specific weight (assigned by RECS). The estimate for population-weighted exposure is the sum of the product of people and exposure for each home divided by the total number of people. This calculation was done for each of the unique parameter combinations. The range for excess population-weighted exposure for each gas usage model is given in Figure 6.

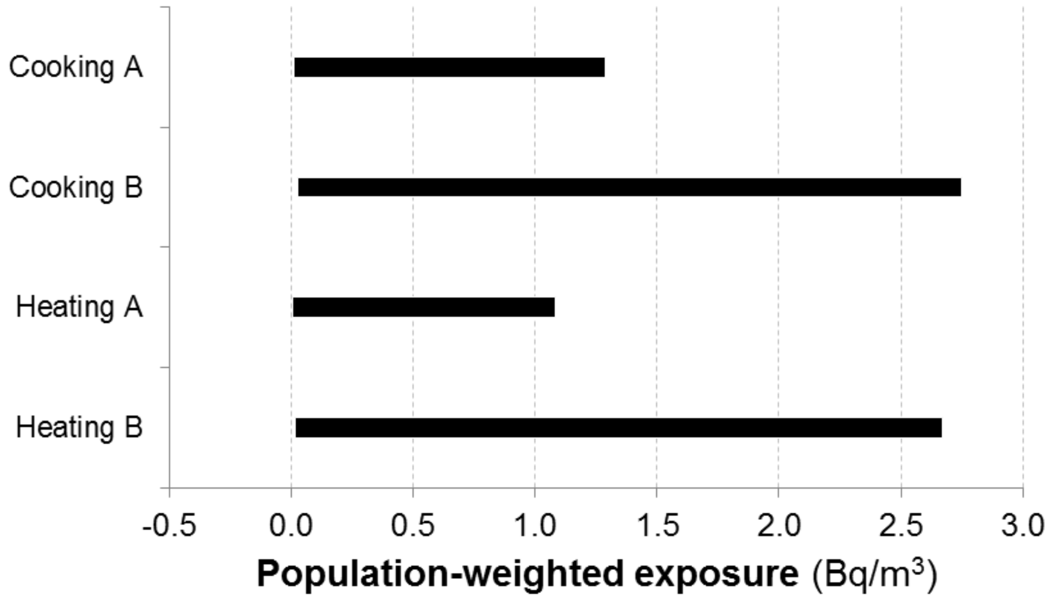


Figure 6: Range of excess population-weighted exposure associated for unvented cooking and heating gas usage models.

Figure 6 shows that the maximum population-weighted exposure from radon in natural gas is less than 2% of the U.S. EPA action level of 148 Bq/m^3 (4 pCi/L) for indoor air.

The exposure estimates in Figure 6 do not use the 70% occupancy factor typically applied when calculating exposure at home (*80*). For the case of radon exposure from natural gas, assuming 100% occupancy was the conservative assumption because a majority of exposure to combustion byproducts occurs during and immediately after the use of unvented gas appliances (*126*, *127*, *146*). Moreover, both cooking and supplemental heating are associated with occupancy, and at least one person is near source during cooking and probably more in an unvented space heating scenario. A related issue is that people near the source (e.g., the person cooking) will likely see higher exposures compared to people in another part of the house. The mass balance, instantaneous mixing approach underestimates this maximum exposure, particularly during combustion (*126-128*, *147*). In a test house, Traynor *et al*. found that maximum exposure to combustion byproducts from a gas range were underestimated by around 20% (*127*). However, higher exposure for the people near source was not incorporated into the exposure model because the lung cancer model is intended to be used for population-level exposure (*81*)

<u>Cancer risk due to radon in natural gas</u>

In 2009, 41,169 lung cancer cases were reported in the Northeast for a population of 55.2 million people. This gives an incidence rate of 65 per 100,000 (*148*). Using the 95% confidence interval Turner *et al.* (2011) calculated for the Northeast U.S. radon hazard ratio (HR) 1.12-1.53 per 100 Bq/m^3, the lifetime excess lung cancer risk is computed for the minimum and maximum population-weighted exposures determined previously. Note that Turner *et al*.'s HR model accounted for interactions such as smoking. Minimum and maximum cancer risk estimates for each of the gas usage scenarios are given in Figure 7.

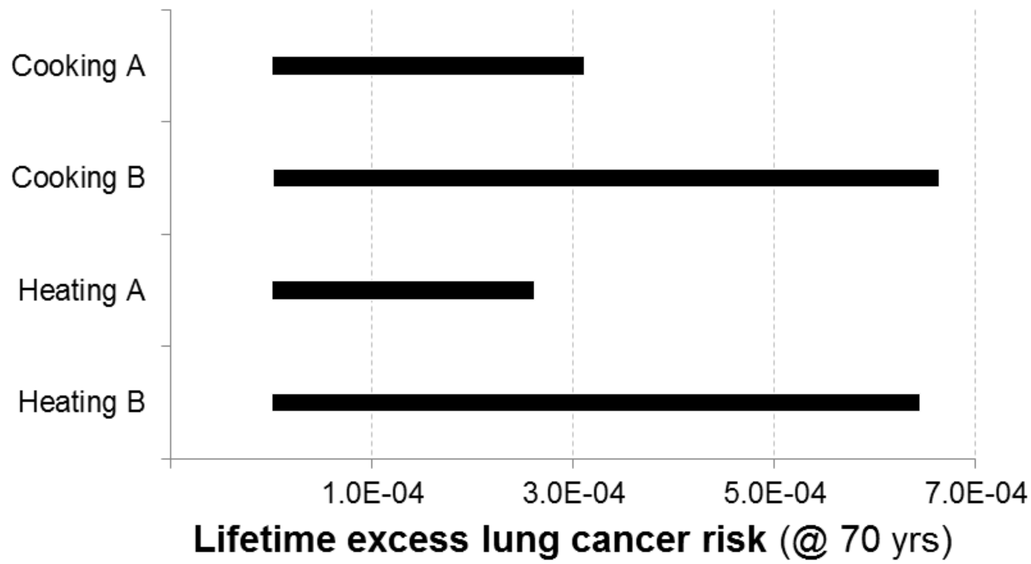


Figure 7: Range of lifetime (70-yr) excess lung cancer risk for the population-weighted exposures associated for the unvented cooking and heating gas usage models.

Figure 7 shows a wide range for the lifetime lung cancer risk for the Northeast population. The maximum lifetime excess lung cancer risks for unvented cooking and heating are $6.6x10^{-4}$ and $6.4x10^{-4}$, respectively. This population-level risk is calculated for uniform average conditions over an entire population. However, the data show that a confluence of high use in small spaces with low air exchange rate is required in order to exceed a 10^{-4} population risk. It would be unlikely that such parameter combinations describe population-level risk (e.g., not every home that uses natural gas has low AER), so these exposure and lung cancer risk estimates are conservative.

With the highest population-weighted exposure modeled for cooking and an HR of 1.53 per 100 Bq/m^3, <240 additional annual lung cancer incidences are estimated for cooking-related exposure. Therefore, it is not likely that radon in natural gas used for cooking will have a measurable effect on lung cancer incidence in the Northeast, where there were approximately

4,200-6,200 radon induced cancers in 2009, assuming 10-15% of all lung cancers are due to radon (*78*). A mortality estimate for heating is not possible because the actual population using unvented gas appliances for heating is unknown.

Sensitivity analysis

A sensitivity analysis of the ranges of parameters in the exposure model (natural gas radon concentration, supply mixing, transit, unvented gas usage, air exchange rate, and dilution volume) as well as the 95% CI for the Northeast hazard ratio was conducted. Lifetime excess lung cancer risk was calculated for the range of each parameter while the remaining parameters were set to mean values (gas usage, Rn conc., transit time, hazard ratio) and median values (AER) under the assumption of no supply mixing or dilution volume adjustment. Shown in Figure 8 (a) and (b) are the results for unvented cooking and heating, respectively.

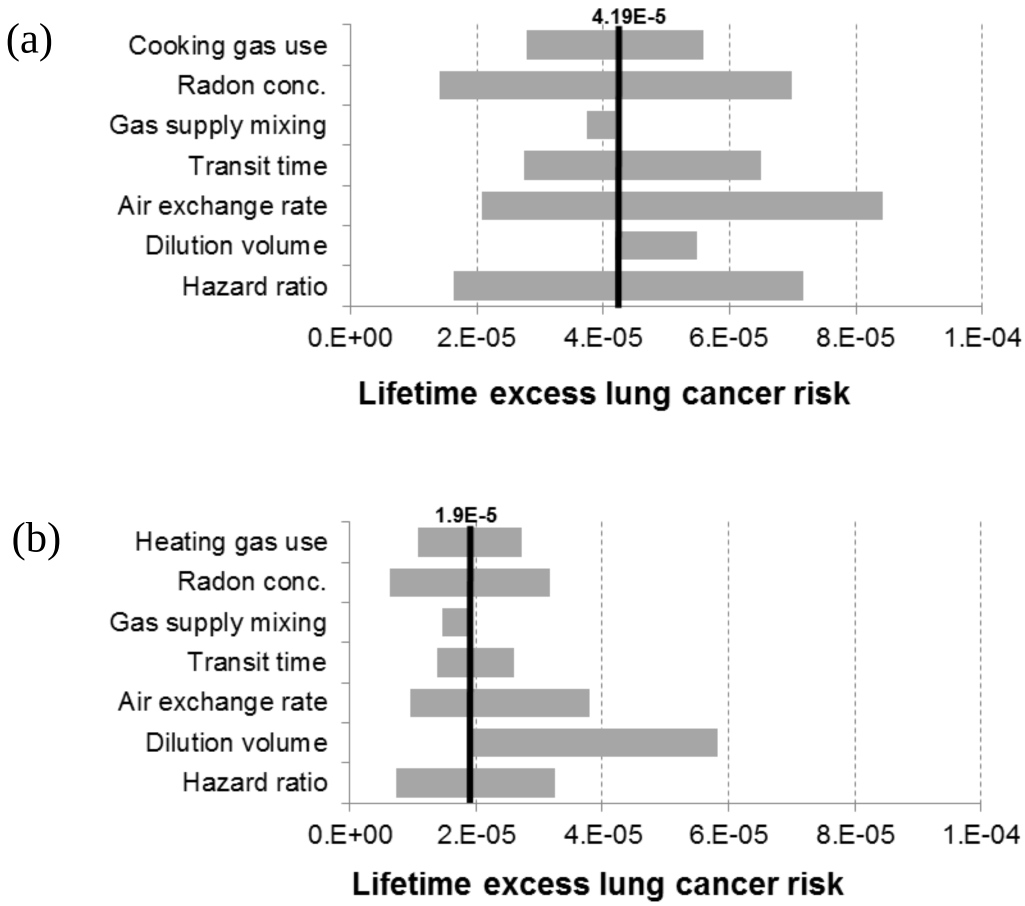


Figure 8: Sensitivity of lifetime excess lung cancer risk to assumed ranges of model parameters. (a) unvented cooking (b) unvented heating.

The most sensitive parameters in the cancer risk model for cooking are the radon concentration and AER. Uncertainty associated with HR is also significant to the model. Supply mixing has the smallest effect on the exposure model for cooking. Dilution volume is the most sensitive parameter in the model for unvented space heating. This analysis shows that intentionally restricting interior air flow, as is required for zonal heating, significantly increases the lung cancer risk, in relative terms.

How “hot” does the gas have to be to exceed 10-4 lung cancer risk?

The radon concentration required at the “burner tip” to exceed 10^{-4} lung cancer risk based on population-weighted exposures over a 70-year period was estimated. Table 7 gives the required radon concentration (Bq/m^3) for each of the unvented cooking and heating models for two levels of in-house dilution using the mean and 95% CI Northeast HR from Turner *et al.* 2011 (*81*).

Table 7: Required radon concentration (Bq/m^3) at the burner tip to exceed 10^{-4} lung cancer risk over a 70-year period. The average HR for the northeast US is 1.31 and the 95th percent confidence range around that estimate is 1.12, 1.53). Two assumptions for dilution volume are contrasted, whole-house and 1/5 house (partial). A low bound for the air exchange rate is assumed in each case.

Hazard ratio (per 100 Bq/m^3)	Dilution volume	Cooking		Heating	
		A	B	A	B
1.12	whole	8,000	4,000	23,300	9,300
	partial	6,400	3,000	7,600	3,100
1.31	whole	3,100	1,600	9,100	3,600
	partial	2,500	1,100	2,900	1,200
1.53	whole	1,800	900	5,300	2,100
	partial	1,400	700	1,700	700

The required radon concentration is higher than recent measurements of gas entering the transmission system (*77*) for all of the cases using the low bound HR. With high gas usage, and low dilution pipeline radon concentrations above 700 Bq/m^3 could result in a $>10^{-4}$ lung cancer risk, a level observed for gas entering Spectra Energy’s transmission line.

What is the exposure under a worst case scenario?

Though not well-documented, there are people who use unvented gas appliances as primary heating (*116*, *128*). If all the Northeast apartments in the RECS survey (484 total) are modeled such that 100% of their 2009 natural gas consumption for heating (Q_{SPH} from Equation 2) was by unvented gas appliances and all other model parameters were chosen to maximize radon concentration indoors (Table 8), then the exposure distribution would resemble that in Figure 9. (This is in contrast to the maximum amount of unvented heating in the population-level exposure model (Figure 5) for which 8% of total heating energy use came from unvented appliances.)

Table 8: Parameter assumptions used to model exposure in apartments for the heavy use of unvented heating scenario. Radon concentration is assumed to be at the burner tip.

Radon concentration (Bq/m3)	4,440
Air exchange rate (1/hr)	0.12-0.23
Dilution volume (m^3)	entire heated volume
Occupancy fraction	100%

The resulting distribution of annual average exposure for all Northeast apartments in the RECS survey is given in Figure 9.

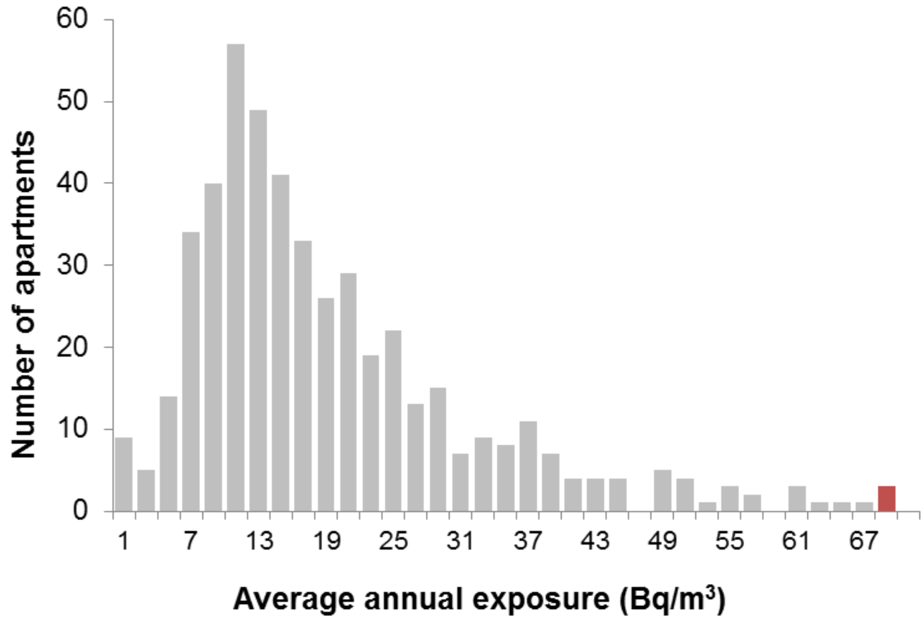


Figure 9: Distribution of annual average exposure for all Northeast apartments in RECS for the 100% use of unvented heating scenario. The results for three apartments were deemed outliers due to anomalously high gas consumption for heating (red bar to the right), which would only be possible if air exchange rates were significantly higher than what was modeled.

Figure 9 is skewed towards high exposure due to the fact that only a low AER was modeled. In reality, gas consumption for heating is positively correlated to AER (*149*). Even with this bias, the potential excess radon exposure in 70% of Northeast apartments surveyed would be less than 10% of the EPA's 148 Bq/m^3 action level. It is important to note that exposure to other combustion byproducts (e.g., nitrogen dioxide, carbon monoxide) would likely be the greater concern with this level of unvented gas combustion and minimal air exchange (e.g., *113, 117, 126, 128*).

Discussion

Estimated excess population-weighted lung cancer risk due to residential unvented natural gas combustion in the Northeast is probably low, even when using the upper bound HR of 1.53 per 100 Bq/m^3. As modeled, it is essentially smaller than the noise in the estimate of annual lung cancer incidence in the case of cooking, and presumably for unvented heating. The magnitude of the potential risk to human health calculated in this study is larger than what was found by Krewski and Anspaugh. The main reasons for this result include the use of higher radon concentration assumption of natural gas in the residential supply and the use of a Northeast-specific lung cancer model. At this time there is no support for the high mortality case considered possible by Resnikoff. Based on current information, it is unlikely that elevated radon in Marcellus Shale gas supplied to Northeast U.S. homes will rise to the level of a major public health threat. On the other hand, this analysis shows that radon concentrations known to exist in locally-produced gas are high enough to be a concern to the people who consume significant quantities of natural gas in small spaces with low air exchange rates. It is currently unclear how many people fall into this category.

In addition to the population level assessment, an extreme scenario of exposure was modeled: apartment dwellers who do all of their heating through unvented gas appliances. Even in these cases, potential excess exposure will be <10% of the EPA's action level (148 Bq/m^3) for most apartments.

The potential excess exposures to radon in natural gas modeled in this study are very small compared to typical background levels in homes and outdoors. This result is important from a public policy perspective, particularly if the questions relate to the allocation of money for radiation protection. The individual perspective, however, could be very different especially for a person whose background exposure is low. The actual level of radon in natural gas pipelines is not public information. Without a thorough understanding of the concentration and variability of the natural gas radon concentration it is difficult to dismiss public concerns and to devise a measured regulatory approach to this issue. Concerned members of the public can take simple steps to mitigate the risk. For example, opening windows can increase the air exchange rate by orders of magnitude (*138, 150*), which would dramatically reduce any potential radon exposure.

There are numerous limitations to note regarding this analysis, but only those that might lead to higher exposure are worth mentioning because the lower bound for lung cancer risk is already approaching zero. The assumptions for the plausible range of radon concentration of natural gas delivered to the transmission system are based on insufficient information. With current information, the existence of radon "hot" spots cannot be ruled out. Also, while RECS is a useful source of data on Northeast homes and energy consumption, the data represent a small sample of around 20 million homes in the Northeast and certain features of the data are less representative than others. Whether the weighted value of individual homes and home occupancy rates are appropriate inputs to derive population-weighted exposure is unknown. Errors in the RECS survey and end-use model could also impact these results.

AER models, including the one used in this study to calculate population-weighted exposure, have shortcomings (*141*). The upper and lower bounds for AER fail to capture house-level variability and could underestimate exposure in homes that are very tight.

Finally, the excess lung cancer risk estimates in this study are sensitive to the HR. Thus, the main limitations given in Turner *et al.* also apply to this study, namely that their study was based on mean county-level radon data as opposed to more direct measurements in homes.

Conclusion

Natural gas being supplied to Northeast U.S. residential consumers will contain higher levels of radon compared to conventional and geographically-distant supplies that have sustained this region for decades. Even with more radioactive gas, the lung cancer risk is unlikely to be significant at the population-level in almost all of the gas usage and housing stock configurations examined for this study. Segments of the population, small as they might be, that operate unvented gas appliances in poorly ventilated spaces are likely to exceed a 10^{-4} excess lifetime lung cancer risk if the natural gas radon concentration is at levels already measured for Marcellus Shale gas. More measurements of the natural gas radon concentration are needed to rule out the possibility that it could be higher, which would have wider health implications.

Abbreviations

AER – Air exchange rate

AFUE - Annual fuel utilization efficiency

Bq - Becquerel

Btu – British Thermal Unit

EPA – Environmental Protection Agency

HR – Hazard Ratio

pCi - picoCurie

RECS – Residential Energy Consumption Survey

Appendix

Assumptions for cooking estimate A

Documentation for the conversion of qualitative frequencies associated with natural gas cooking to “meals per day.”

Table 9: Imputed “meals per day” for respondent-reported frequencies of oven use and *hot meals*.

Qualitative frequencies from RECS	Reporting homes: oven	Reporting homes: *hot meal*	**Imputed meals per day**
Not used (if volunteered)	78	-	-
Three or more times a day	44	90	3.00
Two times a day	75	232	2.00
Once a day	165	405	1.00
A few times a week	320	235	0.50
About once a week	143	33	0.14
Less than once a week	172	38	0.10

Assumptions for cooking estimate B

Documentation for the conversion of qualitative frequencies associated with clothes washing and drying to “dryer loads per day.” The frequency of dryer use is estimated from the frequency of clothes washing. Consumption of 30,000 Btu is assumed for each time the dryer is used.

Table 10: Imputed “washing loads per week”

Frequency clothes washer used	Reporting homes	**Imputed number of loads per week**
1 load or less each week	27	1
2 to 4 loads each week	121	3
5 to 9 loads each week	109	7
10 to 15 loads each week	30	12.5
More than 15 loads each week	5	15

Table 11: Imputed "fraction of washing loads that dryer was used"

Frequency clothes dryer used	Reporting homes	**Imputed fraction of washing loads that dryer was also used**
Use it every time you wash clothes	301	1
Use it for some, but not all, loads of wash	63	0.5
Use it infrequently	8	0.33

An upper limit for cooking consumption of 25,000 Btu per person per day was established because the result was an impractical amount of cooking. The data used to establish this limit are given in Figure 10.

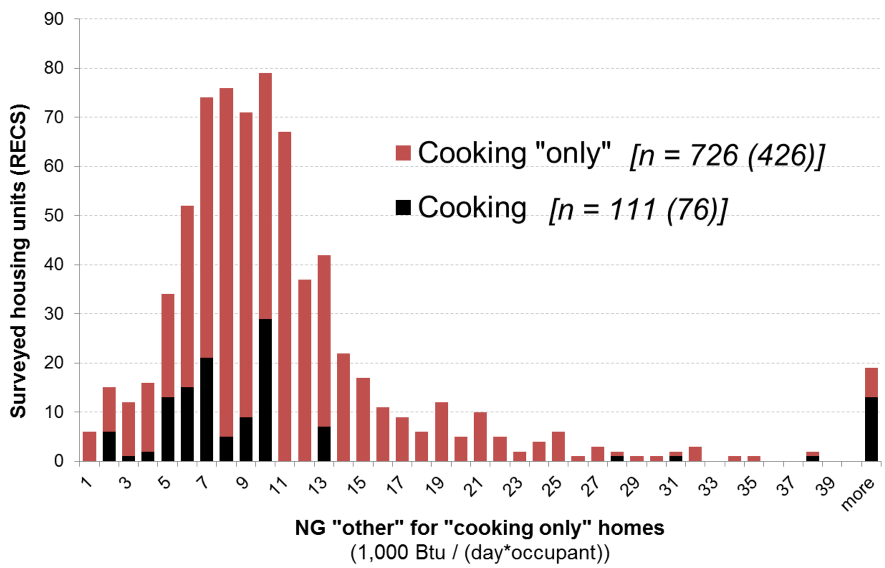


Figure 10: Distribution of homes for which Q_{other} could only be attributed to cooking. Cooking "only" includes homes with natural gas space or water heating appliances. The other category for cooking includes homes without any other natural gas appliances besides a cooking range. The total number (n) for each category is given. The number of housing units that are apartments are in the parenthesis. The upper limit of 25,000 Btu per day per occupant represents the 95th percentile. The mean is 12,000 Btu per day per occupant.

Assumptions for heating estimate B

An AFUE was assumed for primary heating appliances depending on the appliance's reported age in RECS. The AFUE for appliances less than 10 years old was assumed to be 0.95, for 10-20 years old 0.85 was assumed, and for >20 years old 0.7 was assumed.

Chapter 3: Performance of alternative regulatory approaches for hydraulic fracturing surface water withdrawals[1]

Introduction

There are numerous concerns about the impacts to regional water resources from developing the Marcellus Shale (*20, 37*). Surface water sedimentation due to erosion of well pads, access roads, pipeline easements, etc. may cause ecological harm (*10, 18, 151*). Groundwater contamination from methane may occur if well casing is not properly installed and/or maintained to prevent fluid migration (*25-28*). The potential for groundwater contamination by the hydraulic fracturing process from natural or induced hydraulic connections in the geologic strata overlying the producing reservoir has also been investigated (*29, 152, 153*). Though the risk of contamination via this mechanism is theoretically low with deep reservoirs like the Marcellus Shale (*154*), previously drilled oil and gas wells, which are common in this region, may short-circuit the geologic "frac" barriers (*155, 156*). The wastewater generated in large volumes immediately after the hydraulic fracturing process and in smaller volumes over a well's productive life may contain chemicals used in hydraulic fracturing as well as high concentrations of dissolved salts and heavy metals, including naturally-occurring radioactive material (*20, 157*). There are risks to ecosystems and drinking water quality from unintentional releases of this wastewater to the environment (e.g., leaks and spills) (*18, 37*), from illicit dumping (*158*), and ineffective treatment of wastewater prior to disposal (*39, 159*).

This paper focuses on the environmental impacts of water withdrawals for shale gas development and what is being done to manage them. Reductions to instream flows can adversely affect aquatic, riparian, and floodplain habitats and the biota dependent on them.

[1]Austin L. Mitchell, Elizabeth A Casman, Mitchell Small, Performance of alternative regulatory approaches for hydraulic fracturing surface water withdrawals, accepted for publication in Environmental Science & Technology on September 16, 2013

Water withdrawals during low flow and drought conditions carry the most risk, but maintaining the stream's natural seasonal variability is also important for healthy aquatic ecosystems. (*160, 161*). Potential effects include the disruption of important stream features such as pools and riffles and diminished connectivity within basins. Withdrawal-induced temperature changes can also alter water quality and chemistry (*160-164*). Water withdrawals from degraded sources may be beneficial to water quality downstream (*165, 166*), but withdrawals from high quality surface waters can cause downstream functions to be impaired by reducing dilution capacity (*167*).

Water withdrawals are regulated differently in each of Pennsylvania's four major river basins. The Pennsylvania Department of Environmental Protection (PADEP) has regulatory authority over Pennsylvania's portion of the Ohio River Basin (ORB) (*168*). The ORB covers most of western Pennsylvania except for the northwest corner near Lake Erie, which is part of the Great Lakes Basin Compact. The Delaware River Basin Commission and Susquehanna River Basin Commission (SRBC) have authority to regulate water withdrawals in the eastern two-thirds of the Commonwealth.

This study evaluates the impacts of different water withdrawal management options in the ORB, a watershed that covers 40,500 km^2 in western Pennsylvania, contains 22,000 kilometers of second-order and larger streams, and four major rivers (Allegheny, Monongahela, Youghiogheny, and Beaver) (*169*).

Background

In 2008, the PADEP began requiring shale gas drilling operators to submit water management plans (WMP) for each hydraulic fracturing water source. Water use data were digitized from 233 well record and completion reports (*170*) from early 2011 (all of those available in March 2013) . These reports indicated that more than 70% of the water used for hydraulic fracturing of these wells was taken by operators directly from surface water in Pennsylvania. For the first half of 2011, the SRBC reported that 75% of water withdrawals for unconventional gas development were coming directly from surface water sources in their basin (*171*). Water purchased from public and bulk water suppliers was the second largest source. Since these entities obtain the majority of their water from river and reservoir intakes (*172*), it is likely that more than 85% of the shale gas industry's water use was taken directly or indirectly from surface water sources. The third largest source was reused water, known as "produced water" (waste brine) that returns to the surface within a few weeks after a well has been completed (hydraulically fractured). Reused water constituted an average of about 12% of the water used for hydraulic fracturing from the digitized well record and completion reports; on a per-well basis, some reported 25% reused water use and others reported zero.

Table 12 shows that the average water use for horizontal wells approximately doubled from 2008 to 2011, due primarily to the increased measured depth of wells (which includes vertical and horizontal sections). However, the water-use intensity (WUI) (*173*) for both vertical and horizontal wells decreased over the same period from 32 to 14 m^3 of water per meter of hydraulically-fractured formation, possibly indicating more efficient use of water during the hydraulic fracturing process.

Table 12: Characteristics of water use by well type, both vertical and horizontal, and estimated annual water use in the Pennsylvania portion of the Ohio River Basin (ORB) for hydraulic fracturing (Appendix Water use data and estimation methods). Water use intensity (WUI) is calculated from statewide hydraulic fracturing water use data.

	Vertical wells				Horizontal wells				Estimated water use in ORB for hydraulic fracturing (m^3)
Year	No. of wells[1]		Avg. water use (m^3)	WUI (m^3/m)	No. of wells[1]		Avg. water use (m^3)	WUI (m^3/m)	
2008	141	*42%*	3,900	144	35	*71%*	11,000	28	930,000
2009	155	*63%*	5,000	164	114	*83%*	12,300	32	2,200,000
2010	107	*54%*	4,400	115	274	*73%*	17,000	16	5,100,000
2011	54	*13%*	8,700	62	612	*56%*	17,500	14	11,200,000
2012	42	-	1,500	-	579	-	16,400	-	9,600,000

[1] Estimated number of wells (by type) hydraulically fractured each year and percent of wells for which water use data were reported, as of March 2013.

In 2011, approximately11.2 million m^3 of water was used for hydraulic fracturing in Pennsylvania's ORB, which represents an 11-fold increase since 2008. Despite this dramatic growth, water use for natural gas development in Pennsylvania constitutes only a small fraction of surface water withdrawals within Pennsylvania's ORB (Appendix Surface water withdrawals in the Ohio River Basin). Basin-wide comparisons, however, do not address the potential for water withdrawals to have localized impacts on water quantity and quality.

Where to source water can be a complex decision for operators in the Marcellus Shale. Consideration will be given to the consistency and chemistry of the supply, regulatory aspects, potential environmental impacts, and cost (*12*). There is no fee or charge for taking water from rivers or streams in the Upper Ohio River Basin, but costs are incurred in transporting water (*37*, *174*, *175*). This provides incentive to source locally and results in small rivers, streams, and creeks being an important part of the industry's freshwater portfolio in the ORB. Of all surface water sources covered by WMPs on file with the PADEP as of July 2012, approximately 60% of withdrawal sites have upstream drainage areas smaller than 518 km^2 (200 mi^2), while 40% are smaller than 259 km^2 (100 mi^2) (*176*). Small streams are often essential to greater watershed and ecological health, and are important to regional tourism and recreation (*177*).

Current approaches for managing surface water withdrawals

Flow statistics used by PADEP

The $Q_{7\text{-}10}$ is a statistical estimate of the average minimum streamflow that can be expected for 7 consecutive days once every 10 years (*178, 179*). The PADEP considers basin-wide water withdrawals summing to less than 10% of the $Q_{7\text{-}10}$ flow to be *de minimis,* which means that withdrawals up to this amount could occur on a daily basis, including during declared droughts, presumably without significant ecological effects (*180, 181*). In intermediate to large streams and rivers (drainage areas >500 km^2) in western Pennsylvania, 10% $Q_{7\text{-}10}$ typically exceeds what a single operator would propose to withdraw on a daily basis (Appendix: Water use data and estimation methods).

When the volume of the proposed withdrawal (plus other upstream withdrawals) exceeds 10% $Q_{7\text{-}10}$, withdrawals are still possible, but are subjected to a "passby flow" condition, which means that they may only occur on days when the instantaneous flow exceeds the passby flow at the withdrawal location. In other words, the passby flow defines a minimum flow that must be maintained in the stream for ecological purposes (*162, 182, 183*). For compliance with the passby flow, the PADEP requires entities withdrawing water to verify sufficient streamflow prior to commencing withdrawals.

PADEP varies the passby flow with the quality and designated uses of the source water. For exceptional value and high quality streams (*184*) the passby flow is 25% of the average daily flow (ADF). This means that water withdrawals are prohibited when the instantaneous flow is below 25% of the ADF at the withdrawal site. The passby flow for degraded streams, such as those impacted by acid mine drainage, is set at 15% ADF (*180, 185*).

Flow statistics used by other regulatory entities

In contrast to the PADEP, the New York State Department of Environmental Conservation's (NYSDEC) Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program (SGEIS) and the SRBC's new low flow protection policy rely on monthly flow duration curves (FDCs) to determine unique passby flows for each month. This approach reflects the desire to preserve the natural flow regimes with respect to magnitude and variability, which shape ecological patterns and lifecycles (*160*). The NYSDEC's SGEIS proposes setting the passby flow to a value that is exceeded 60% of the time (the Q60) in each of the driest months (July, August, September). For all other months the passby flow is set to the Q75. For drainage areas smaller than 129 km^2 (50 mi^2), the Q60 is recommended for all months (*167*). The SRBC passby flow rules allow withdrawals 70-95% of the time depending on the size, quality, and other features of the watershed. (*186*) A monthly Q70, the most protective passby flow, is reserved for small, high-value streams. The SRBC reserves some flexibility in implementation at sensitive locations (*186*).

Figure 11 contrasts 25% ADF to a "monthly Q75/60" passby flow for the U.S. Geological Survey (USGS) stream gage on Laurel Hill Creek at Ursina, PA, a high quality tributary of the Youghiogheny River used for fishing and recreation (*187*). Under the 25% ADF passby flow, withdrawals can occur more frequently during high seasonal flows (winter to spring) but are more restricted during low seasonal flows (summer to fall). With the monthly Q75/60, water withdrawals are allowed more consistently throughout the year. Though different in how withdrawals are distributed, both passby flows would allow water withdrawals approximately the same number of days in a typical year at Laurel Hill Creek.

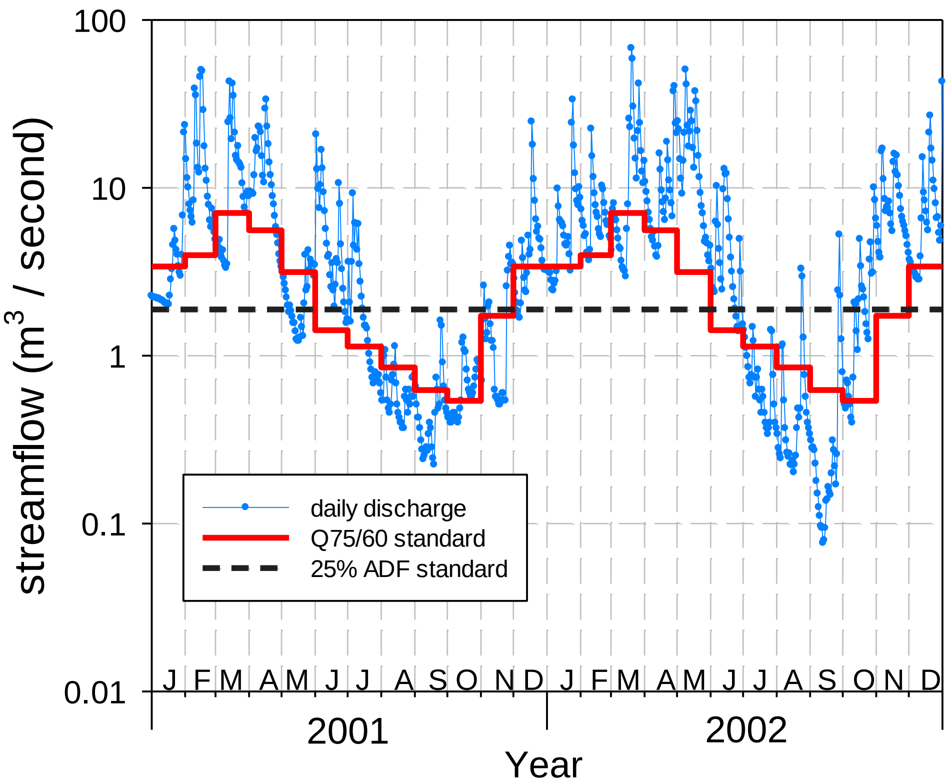


Figure 11: The 25% average daily flow (ADF) (dashed line) and monthly Q75/60 (solid red line) compared to the daily discharge values (blue) for Laurel Hill Creek (USGS 0308000) at Ursina, Pennsylvania between 1/1/2001 and 12/31/2002. Both passby flows were calculated from the discharge data between climate year 1942 and 2002. Passby flow equal to 25% ADF prohibits more withdrawals during periods of low-flow and allows more withdrawals during periods of high-flow than does the monthly Q75/60.

Estimating stream statistics at ungaged withdrawal locations

Operators have flexibility in how they estimate $Q_{7\text{-}10}$ or ADF in their WMPs when the proposed withdrawal location is ungaged. They may use values determined from flow records at a more-distant streamgage, scaled by drainage area, to estimate a $Q_{7\text{-}10}$ or ADF statistic, provided that the following are true: (1) the upstream drainage areas of the index streamgage and the withdrawal point are within a factor of three of each other, (2) the two drainage areas share similar geomorphic and climatic traits, and (3) both flow regimes are minimally altered by upstream withdrawals, diversions, and mining (*180*, *188*).

Scaling flow statistics from an index gage by applying the drainage area ratio (*189*) is the simplest approach to estimating statistics on an ungaged stream. A study of streamgages in Pennsylvania found that this method of estimating $Q_{7\text{-}10}$ resulted in errors on the order of ± 33% or less in 80% of the gage-to-gage comparisons examined (*190*). The accuracy of the index gage approach could be improved using transformation techniques, such as base-flow correlation (*191*) or maintenance of variation extension (*192*). However, these methods require a sufficient number of overlapping discharge measurements at the withdrawal location and in the index gage's discharge record. Eng *et al*. compare the bias in these transformation methods (*193*), and found less bias when the overlapping discharge measurements include a larger range of flows.

The most common method for estimating $Q_{7\text{-}10}$ and ADF absent an appropriate index gage is a web application hosted by the USGS (PA StreamStats). This application allows operators to predict $Q_{7\text{-}10}$ or ADF at any point along any perennial stream in Pennsylvania (*176*). Predictions are derived from a set of regression models published by Stuckey (2006) that predict flow statistics from basin characteristics (*194*). ADF was predicted using weighted least-squares from the input variables drainage area, mean elevation, annual precipitation, percent forested area, and percent urban area. Stuckey computed a standard error of 12% for the ADF predictions.

Separate generalized least-squares regressions (*195*) were employed to predict Q_{7-10} in five low-flow regions (LFRs) in Pennsylvania. The ORB in Pennsylvania occupies LFR3 and LFR4 (Appendix Low-flow regions in Pennsylvania). The LFR3 model uses the variables, drainage area, mean elevation, and precipitation. The LFR4 model only uses drainage area and precipitation. The standard errors for the Q_{7-10} prediction for LFR3 and LFR4 are large, 54% and 66%, respectively (*194*).

<u>Streamgage data requirements for USGS Streamstats regression models</u>

Only continuous record streamgages in which the natural flow regime has been minimally-altered by human activities (including underground mining, surface development, significant withdrawals, or significant upstream diversions or impoundments) are acceptable for use in the USGS regression models (*194*). The 2006 USGS regression models for Q_{7-10} and ADF employed historical average daily discharge records from 63 continuous record streamgages in or near the Pennsylvania portion of the ORB, all of which contained at least nine years of average daily discharge records (*194*). Figure 12 shows the sites of these 63 stream gages (24 of which are currently active) and surface water withdrawal locations named in Marcellus Shale WMPs on file with the PADEP as of July 2012. (*194, 196*). Flow records from 33 of the gaging stations contain no discharge data more recent than 1983. (Appendix Streamgages used in this study)

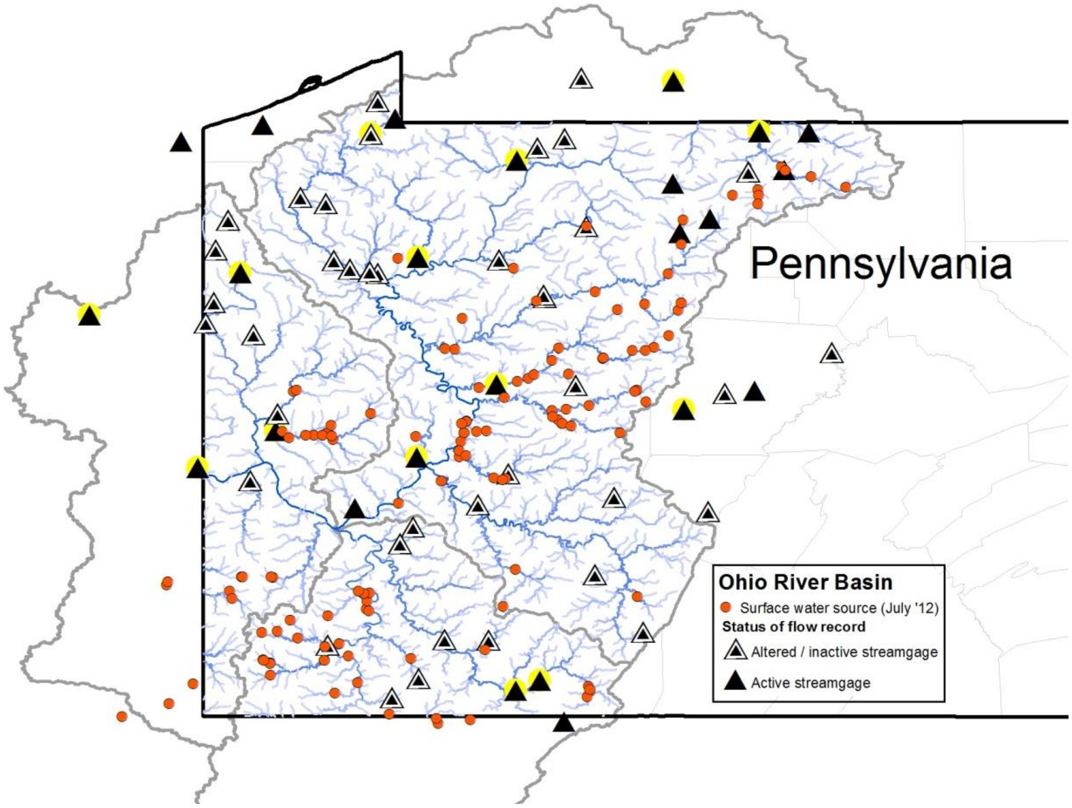


Figure 12: Locations of the 63 continuous record streamgages used by USGS StreamStats and approved surface water sources for hydraulic fracturing as of July 2012 (*197*). The 14 streamgages with 60 or more years of continuous flow record between 1900 and 2002 are highlighted yellow. Most of the hydraulic fracturing withdrawals occur at ungaged surface water locations.

Because the USGS regression models are calibrated using the flow records of streamgages that had been minimally-altered by human activities, these models should only be used to predict flows for other locations that are minimally-altered. The USGS classifies minimally-altered streams as those without extensive mining or and little to none upstream regulation (*179*). In western Pennsylvania, whether this condition is satisfied may be difficult to determine. For example, Pennsylvania only requires reporting of withdrawals exceeding 38 m^3 per day on average (10,000 gallons per day) (*198*). If there are many small, undocumented withdrawals, less water might be available than predicted. Topographic, geologic, or other changes due to subsurface mining and land use also disrupt natural conditions, particularly for groundwater-dominated flows characteristic of smaller streams in dry months (*199*). Figure 13 shows the extent of past subsurface mining in southwestern Pennsylvania. The effects of mining on groundwater flow are long-lasting, difficult to predict (*179*), and may vary over time (*200, 201*).

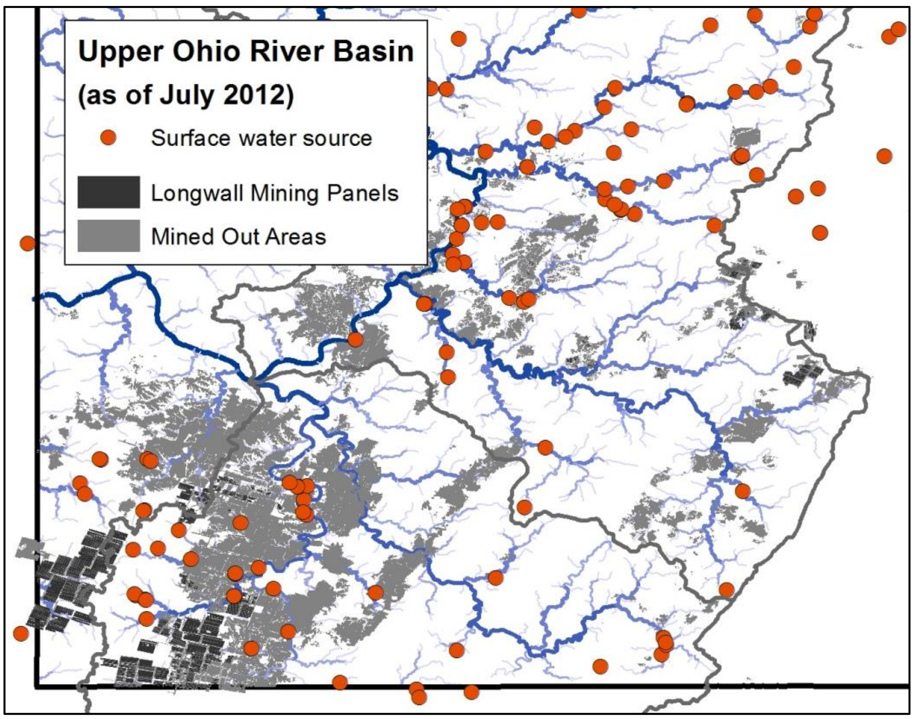


Figure 13: Water management plans for surface water sources as of July 2012 (*197*) from the Ohio River Basin (*202*) in southwestern Pennsylvania. "Mined out" coal areas and active longwall mining panels are indicated (*203, 204*).

Neither the index gage method nor the USGS regressions are appropriate for estimating flow statistics at withdrawal locations with significantly altered flow. Unfortunately, this has not prevented their use in WMPs. Altered streams require case-by-case assessments, but the methods for establishing the appropriate withdrawal conditions are beyond the scope of this analysis.

Analysis

Sensitivity of 10% Q7-10 estimates to number of years in the flow record

In this section bootstrap re-sampling (*205*) is employed to show how $Q_{7\text{-}10}$ estimates derived from the log-Pearson type III distribution are sensitive to the number of years in the flow record (*178, 206*). For each of the 63 ORB streamgages with ≥ 9 years of continuous flow data, the lowest 7-day average flow was calculated for every climate year in the flow record. From the set of the lowest 7-day flows, random samples were drawn (with replacement) to generate 1,000 new sets of 7-day flows for each streamgage's flow record. From Riggs (1980), the log-Pearson type-III distribution was fit to each of the generated sets of 7-day flows and 1,000 estimates for $Q_{7\text{-}10}$ were obtained (*178*). The means and standard deviations of the resultant $Q_{7\text{-}10}$'s were used to calculate the coefficient of variation (CV) of the $Q_{7\text{-}10}$ for each streamgage. Figure 14 plots the calculated CV's against the years in the flow record for all 63 streamgages.

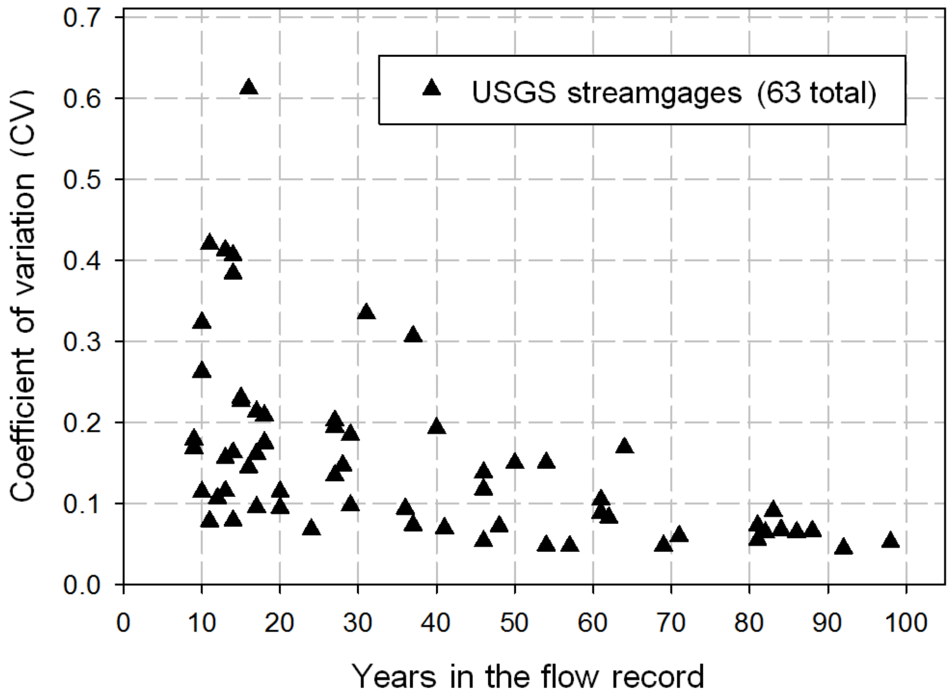


Figure 14: Uncertainty in estimated $Q_{7\text{-}10}$ statistics as measured by the bootstrap coefficient of variation, as a function of the number of years in the flow record. Each triangle corresponds to one of the 63 USGS streamgages used in the 2006 regression.

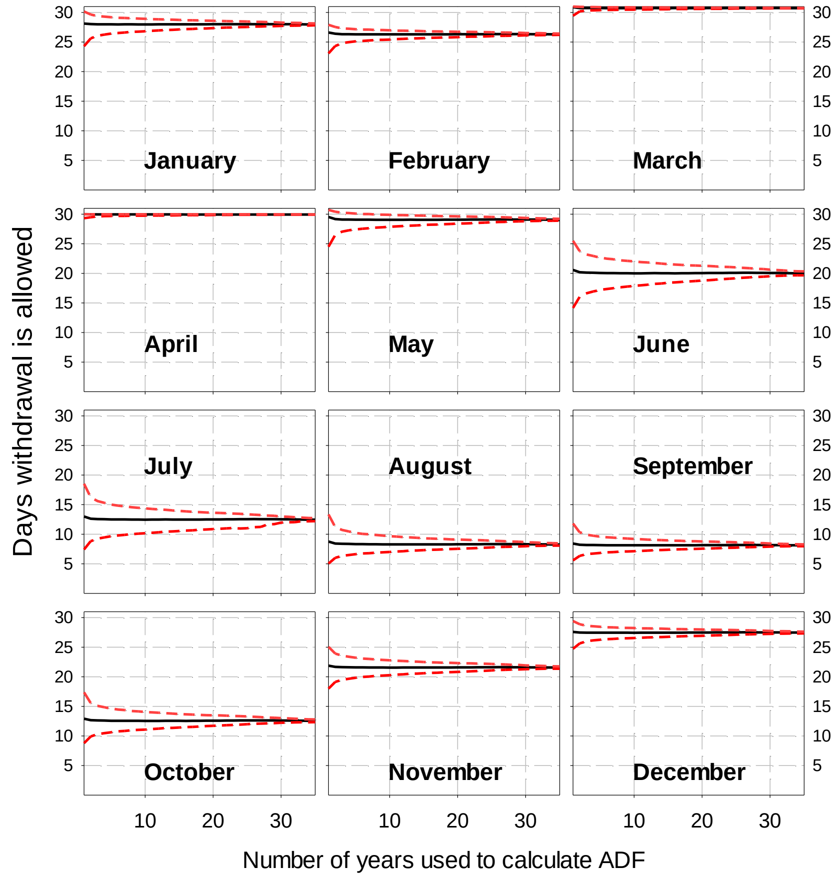
The $Q_{7\text{-}10}$ CV's tend to decrease as the number of years in the flow record increases. Thus longer flow records result in more confident $Q_{7\text{-}10}$ estimates, but the CV's for some streamgages with short flow records were comparable. This means that the lowest average 7-day flows may not have varied much over the time interval considered, but it does not mean that the $Q_{7\text{-}10}$ estimates from short flow records are accurate.

Sensitivity of passby flow to number of years in the flow record

In this section the passby flow is calculated by the two competing methods (25%ADF and monthly Q75/60) with streamflow records of varying length and observe their performance. The data from the 14 streamgages with at least 60 years of uninterrupted flow record were divided into segments ranging in length from 1 to 35 consecutive years of flow. The passby flow statistics were calculated from all such segments, resulting in a collection of biased passby flow statistics, whose performance was compared to passby flow statistics calculated from the full flow record.

The 14 streamgages with at least 60 years of uninterrupted flow record are from small and large rivers: four had upstream drainage areas under 388 km^2 (150 mi^2), the largest drainage area was 4,165 km^2 (1,608 mi^2), and the average was 1,023 km^2 (395 mi^2). (Appendix Streamgages used in this study, Table 14 and Figure 12) The set of biased passby flow statistics were used to compute the fraction of days in each month of the 60-year flow record that days withdrawal would be allowed. For the 25%ADF passby flow statistic, that meant the number of days in the record exceeding that 25%ADF. For the monthly Q75/60 statistics, each month would have its own passby flow, either Q75 (the flow exceeded by 75% of daily flows for that month) or Q60. As with 25%ADF, the number of days in the 60 year record that water could be withdrawn was calculated. This was repeated for all 14 gaged streams. The computed fractions were organized by flow record length (1-35 years) and fit to a beta distribution. The mean and 90% confidence interval (CI) for days withdrawal is allowed were computed. The averages of these values across all 14 streamgages are reported in Figure 15.

(a)



Days withdrawal is allowed
January
February
March
April
May
June
July
August
September
October
November
December
30
25
20
15
10
5
10
20
30
Number of years used to calculate ADF

(b)

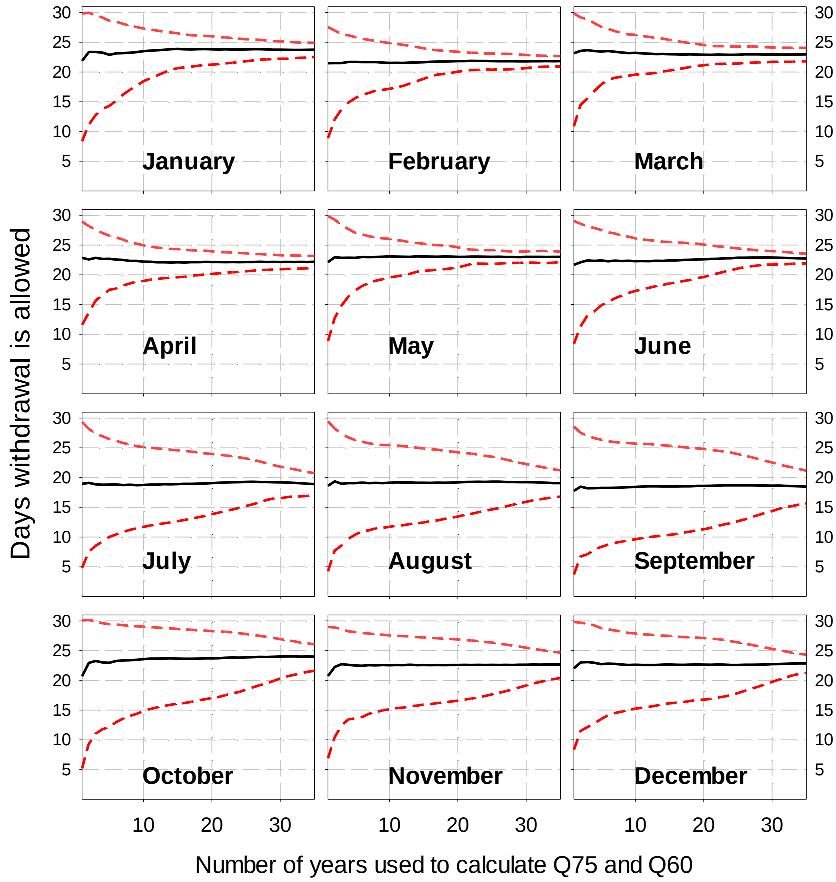


Figure 15: The sensitivity of passby flows to of the number of years in the flow record length. The solid line shows the average number of days withdrawal is allowed for (**a)** 25% average daily flow and (**b)** monthly Q75/60 passby flows, and the dashed lines indicate the 90% confidence intervals.

In Figure 15 (a) the width of the 90% confidence interval in most months is small, even when fewer than 10 years of data are used to calculate 25% ADF. One explanation for this is that daily streamflow in the highest (November to May) and lowest (August and September) flow months is typically well above or below 25% ADF, respectively.

The monthly Q75/60 passby flows have more uncertainty in the number of days withdrawal is allowed than the corresponding estimates for 25% ADF. For example, the July passby flow of Q60 is intended to allow water withdrawals 19days out of 31 (60%), but the 90% CI ranges from 12 to 25 days when Q60 is calculated from 10-year flow records (a typical regulatory minimum). In months with higher average flows (January to May) the monthly Q75/60 could limit withdrawals to less than 60% of the days at the 90% CI. The wider confidence intervals with the monthly Q75/60 passby flow are due simply to the fact that approximately $^{1}/_{12}$ as many daily flow records are used to calculate individual passby flows compared to passby flow based on ADF, which uses all of the flow data in a year.

Ecodeficit from underestimated passby flows

From the biologist's perspective, this uncertainty is important to the decision-making process if it results in the approval of water withdrawals that might actually harm aquatic ecosystems and water quality. In this section how monthly flows could be altered by water withdrawals if the passby flows have been *grossly* underestimated because of data scarcity (allowing withdrawals to occur on more days than intended) is investigated. This involves using the concept of a computed "ecodeficit," which is a dimensionless metric used to provide a quantitative basis for assessing the effects of removing water from a stream (*207-209*). (Appendix Ecodeficit calculations) In practice, ecodeficit is used to analyze water withdrawal scenarios (*160, 186, 210*).

Monthly water demands were derived from reported 2011 hydraulic fracturing operations in the ORB (170, 211) to function as prospective water use scenarios (Appendix Water demand for hydraulic fracturing in the ORB, Figure 18). This involved multiplying the highest number of wells completed in any 30-day period in each Upper Ohio River (HUC-10) sub-basin by the average water use per well (m^3) and dividing by sub-basin (drainage) area (km^2). Three scenarios were selected: (1) 150 m^3/km^2 which represents the average of the maximum monthly demand rate for all sub-basins with at least one hydraulically-fractured well in 2011; (2) 1,000 m^3/km^2, representing the highest rate among sub-basins in 2011 (931 m^3/km^2); and (3) 2,000 m^3/km^2, a plausible high estimate compensating for incomplete water use records and other unknowns.

To simultaneously contrast yearly versus monthly passby flows and show the effects of streamgage record length, three examples of underestimated passby flows for each of the 14 gages were selected, (1) the 5th percentile of all possible 25% ADFs calculated from only 5 years of data, (2) the 5th percentiles of the 12 monthly Q75/60 passby flows calculated from all subsets of 10 years of data, and (3) the 5th percentiles of the 12 monthly Q75/60 passby flows calculated from all subsets of 25 years of continuous record. The 5th percentile represents a *grossly* underestimated passby flow and, for the purposes of this study, it is useful bound for the potential magnitude the problem, but it is not a likely outcome.

For each streamgage, altered flow records were generated for every pairing of the three monthly water demand scenarios with the three biased passby flow rules and the average low-flow monthly ecodeficit was calculated (Figure 16). The Nature Conservancy recommends that for basins larger than 130 km^2 (50 mi^2) the low flow ecodeficit should not exceed 10% (0.1) (*160*). Typical flow monthly ecodeficits were also calculated for the 14 USGS streamgages (Appendix Ecodeficit calculations, Figure 22)

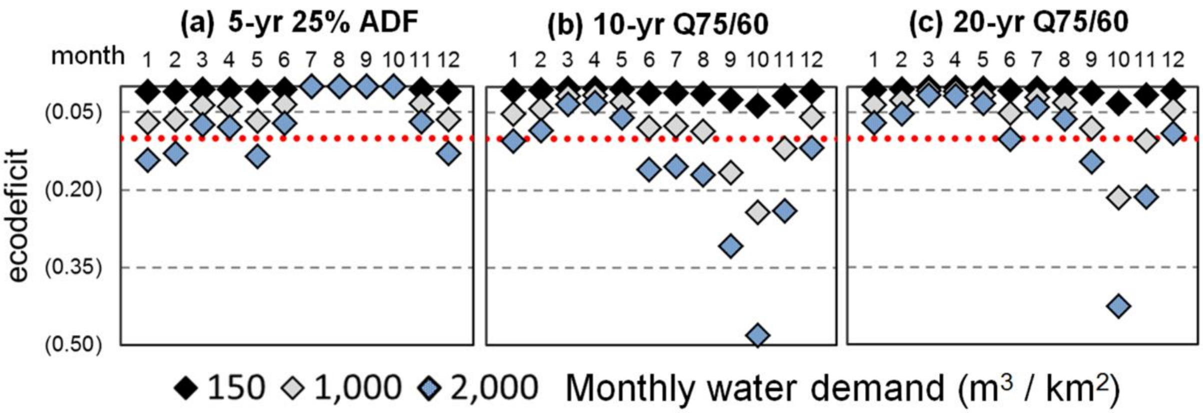


Figure 16: The average monthly low flow ecodeficits estimated for the 14 USGS streamgages for monthly water demands of 150, 1,000, and 2,000 m^3/km^2 subject to underestimated (5th percentile) values of (a) the 5-year 25% average daily flow (ADF), (b) the 10-year Q75/60, and (c) the 20-year Q75/60. The Nature Conservancy threshold of 0.10 is indicated by the red-dashed line. Low flow ecodeficits plotting below this line are considered unacceptable. The passby flow equal to 25% ADF (a) provided the most protection for low flows (June to October) even though only 5 years of flow data were used in its calculation.

Figure 16 shows that monthly water demand equal to 150 m^3/km^2, the 2011 average, does not result in ecodeficits even close to the 10% threshold. However, in areas where development activities are concentrated, this average could be easily surpassed.

Passby flow equal to 25% ADF is most protective of monthly low flows in summer and fall, even when calculated from only five years of data. The monthly Q75/60 passby flow is the least protective if calculated with only 10 years of flow data. Even when monthly Q75/60 passby flow is calculated from 20 years of data, two of the withdrawal scenarios produced unacceptable ecodeficits in October and November, which, for reasons unknown, are not protected to the same level as other “dry” months in NYSDEC’s SGEIS.

Discussion

In this analysis the focus has been on a set of regulatory standards applied to water withdrawals for unconventional gas development, and the circumstances that might lead to their miscalculation and subsequent degradation of ecosystems and water quality in the streams to which the standards were applied. The finding that only five years of continuous discharge data are necessary to successfully implement a passby flow based on the average daily flow is important because it is less than the typical regulatory minimum of 10 years. The recommendation that $Q_{7\text{-}10}$ should be derived from a minimum of 20 years of discharge data is not new (*212-214*). Neither is the finding that 30 to 35 years of flow record are needed to for reliable statistics based on the flow duration curve (*213*, *214*), though the Nature Conservancy recommends a minimum of only 20 years (*160*).

The USGS regression model (PA StreamStats) for calculating $Q_{7\text{-}10}$ and ADF estimates on WMPs is not a better option. Potential errors from the use (and misuse) of these models can be significant. The error in $Q_{7\text{-}10}$ predictions in western Pennsylvania is large (> 50%) and whether WMPs based on StreamStats information provide adequate low-flow protections is unknown. Furthermore, instantaneous flow data are required for implementation of a passby flow standards in the field. The current approach to obtain these data involves observing water depth from a "staff gage" that is loosely calibrated to flow (Appendix: Instantaneous flow measurement errors).

The potential uncertainties presented in this study are not currently incorporated into the approval process for water management plans. Ignoring this uncertainty might result in a miscalculated standard that allows environmentally-damaging water withdrawals to occur. The flip-side of this situation is when the errors are in the opposite direction. Such errors could prevent operators from taking water at times when they would not harm the environment. Thus, both industry and regulators have a stake in determining appropriate and reliable regulatory controls.

Conclusions

The preceding analysis led to the following conclusions. (1) Given the large coefficients of variation for estimating $Q_{7\text{-}10}$ from short flow records, a minimum of 20 years of record is recommended for calculating this statistic. A third of the available flow records in western Pennsylvania do not meet this recommendation. (2) The current passby flow statistic used by the PADEP (15-25% average daily flow) can be reliably estimated with as few as five years of flow record. This statistic is not as sensitive to the potential biases of short-flow records as monthly passby flow statistics. (3) Severely under- or overestimated monthly Q75/60 passby flows may result from using less than 20 years of flow data, but 30 or more years may be necessary to achieve a level of confidence comparable to that of the 5-year ADF. There are only 24 active streamgages with 20 or more years of minimally-altered flow record to cover 22,000 km of streams in Pennsylvania's portion of the ORB. (4) Significant, though plausible, underestimates of the monthly Q75/60 passby flow might fail to prevent water withdrawals in the range of low flows during the driest months of the year. Intolerable low-flow ecodeficits resulted from withdrawal intensity at the level of the highest historical water demand estimates.

The main justification for monthly passby flow standards is to prevent water consumers from dampening seasonal flow variability. Aggregate water demands of the gas industry are typically a small fraction of streamflow during wet months, raising the question of whether PADEP would have anything to gain from switching to a more complex monthly standard, as have neighboring water authorities.

Abbreviations

$Q_{7\text{-}10}$ – 7-day, 10-year low flow

Q60 – flow exceeded 60% of the time

Q75 – flow exceeded 75% of the time

ADF – Average Daily Flow

Bcf – Billion cubic feet (of gas)

CI – Confidence Interval

CV – Coefficient of variation

DRBC – Delaware River Basin Commission

FDC – Flow duration curve

HUC – Hydrologic unit code

LFR – low flow region

NYSDEC – New York State Department of Environmental Conservation

ORB – Ohio River Basin

PADEP – Pennsylvania Department of Environmental Protection

SGEIS – Supplemental Generic Environmental Impact Statement

SRBC – Susquehanna River Basin Commission

USGS – U.S. Geological Survey

WMP – Water management plan

WUI – Water-use intensity

Appendix

<u>Water use data and estimation methods</u>

Water use data were collected from two sources, PADEP Bureau of Oil and Gas Management well completion reports and from FracFocus.org, a "chemical disclosure registry" of self-reported information on unconventional well completions. Under Pennsylvania's Act 13, which became public law in 2012, submission of these data to FracFocus.org is mandatory (*168*). The beginning and end measured depth of the perforation interval (to estimate length of stimulation interval), the hydraulic fracturing date and water use volume were collected from 1,350 well completion reports (*170*). These data were input to Microsoft Excel from reports on file with the Pennsylvania Department of Conservation and Natural Resources as of March 2012. Reports for which the primary stimulation (fracturing) fluid was not water, including liquid petroleum gas, those listed as "completion pending," or reports that contained errors were omitted (approximately 4% of the well completion reports). Hydraulic Fracturing Fluid Product Component Information Disclosure forms were also downloaded from FracFocus.org in January 2013 (*211*), and the hydraulic fracturing ("job") date and "total water volume" entered into Microsoft Excel. These water use databases were joined using the unique American Petroleum Institute (API) numbers assigned to each well and checked for consistency. If the hydraulic fracturing date or the water use volumes disagreed, the manually-entered information from well record and completion reports was confirmed and used. The combined water use database was then joined with the Carnegie Museum of Natural History July 2012 well database (*215*). No water use data was available for a significant number of producing Marcellus Shale wells. Given these data gaps, the order-of-magnitude estimates of total water use in the basin reported in Table

12 were obtained by multiplying the number of producing wells without water use data by the basin-wide average for horizontal and vertical wells. Basin-wide averages were calculated annually and it was assumed that hydraulic fracturing (and thus water use) occurred in the same year the well was drilled, though this may not always be the case.

Surface water withdrawals in the Ohio River Basin

Table 13: 2005 Estimated water withdrawals in the Ohio River Basin portion[1] of Pennsylvania by USGS category (*172*).

USGS water use category	Estimated withdrawals (million m^3/day)	% from surface water
Public supply	1,700,000	94%
Domestic use (self-supplied and public)	680,000	84%
Industrial	2,050,000	97%
Crop irrigation	10,000	67%
Golf course irrigation	10,000	69%
Mining	30,000	37%
Thermoelectric power	6,250,000	100%

[1]From county-level data for Allegheny, Armstrong, Beaver, Butler, Cambria, Clarion, Crawford, Elk, Fayette, Forest, Greene, Indiana, Jefferson, Lawrence, McKean, Mercer, Somerset, Venango, Warren, Washington, and Westmoreland counties.

WMP surface water sources

Figure 17 shows the approved WMP direct surface water withdrawals from the Ohio River Basin and 10% $Q_{7\text{-}10}$ calculated for 42 USGS gaging stations in the region with more than 20 years of daily discharge record. As USGS gaging stations are not co-located with the withdrawal sites, the regression line of 10% $Q_{7\text{-}10}$ on drainage area provides a rough visual indication of which approved withdrawals would exceed 10% $Q_{7\text{-}10}$ (those above the regression line). For such withdrawal sites, it is often the case that the volume of a single proposed withdrawal would exceed the *de minimis* volume, so these withdrawals would be calculated by the passby flow method.

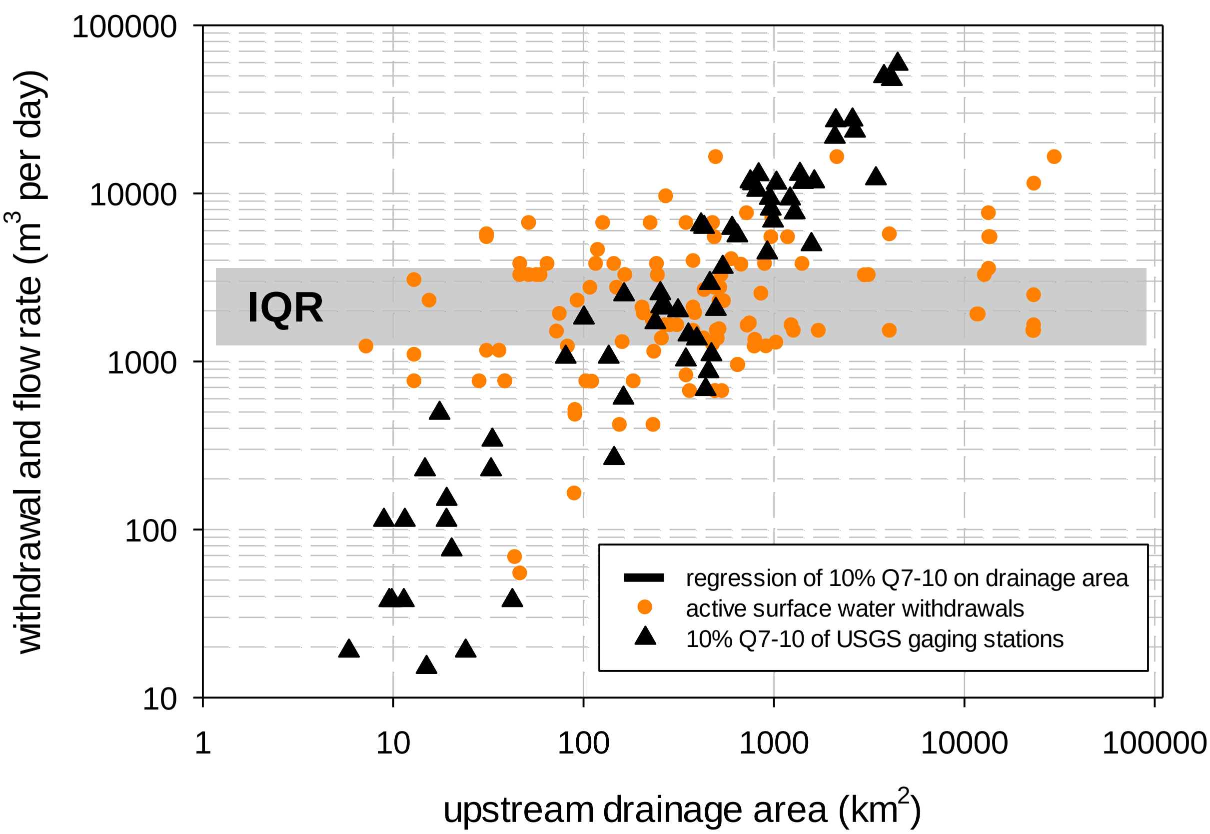


Figure 17: Approved surface water withdrawal rates for hydraulic fracturing in the Ohio River Basin of Pennsylvania compared to 10% $Q_{7\text{-}10}$ statistics for streams by drainage area (*176*). The inter-quartile range (IQR) of these withdrawals is 1,200 to 3,800 m^3 per day (0.3-1 million gallons per day).

Water demand for hydraulic fracturing in the ORB

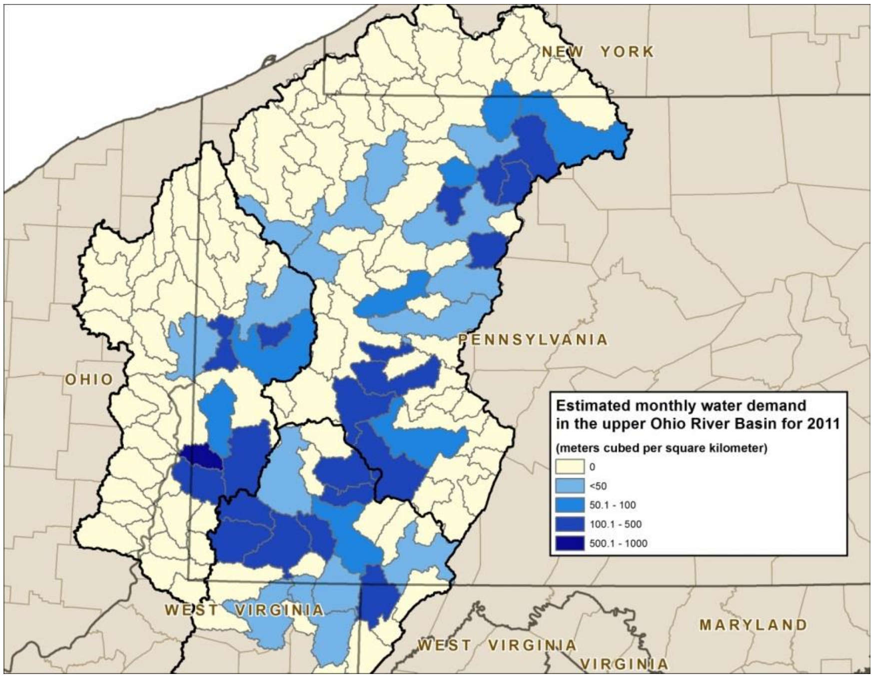


Figure 18: Highest 30-day water demand estimated for Hydrologic Unit Code (HUC) 10 Ohio River sub-basins in 2011 and normalized by sub-basin area. The water use for individual wells is tied to the HUC-10 basin in which the well is located (*216*). County data from Environmental Systems Research Institute (*217*). Wells without a known hydraulic fracturing date were not included.

Low-flow regions in Pennsylvania

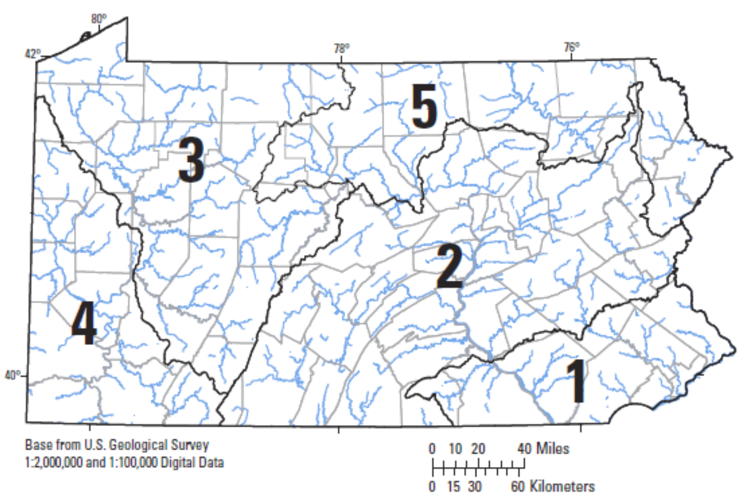


Figure 19: Low-flow regions in Pennsylvania for Q7-10 regressions reproduced from Stuckey (2006) (*194*).

Streamgages used in this study

Table 14: Select basin characteristics for the 63 USGS streamgages used by the USGS to develop low flow and average daily flow regressions for low-flow regions 3 and 4 (*194*). The fourteen highlighted stations were used for analysis of passby flow because they contained at least 60 years of continuous record.

U.S. Geological Survey gaging station	Location	Low flow region	Record Begin	Record End	Drainage area (km^2)	Mean elevation (meters)	Mean annual precipitation (centimeters)
01541000	West Branch Susquehanna River at Bower, PA	3	1915	2002	816	524	113
01541200	WB Susquehanna River near Curwensville, PA	3	1956	1965	951	519	112
01541308	Bradley Run near Ashville, PA	3	1969	1979	18	669	121
01541500	Clearfield Creek at Dimeling, PA	3	1915	1960	961	521	106
01542500	WB Susquehanna River at Karthaus, PA	3	1941	1964	3787	522	106
03007800	Allegheny River at Port Allegany, PA	3	1976	2002	642	628	103
03009680	Potato Creek at Smethport, PA	3	1976	1995	414	605	113
03010500	Allegheny River at Eldred, PA	3	1941	2002	1424	603	107
03010655	Oswayo Creek at Shinglehouse, PA	3	1976	2002	256	620	99
03011020	Allegheny River at Salamanca, NY	3	1905	2002	4165	582	106
03011800	Kinzua Creek near Guffey, PA	3	1967	2002	100	625	114
03013000	Conewago Creek at Waterboro, NY	3	1940	1993	751	469	111
03015000	Conewango Creek at Russell, PA	3	1940	1949	2113	462	115
03015280	Jackson Run near North Warren, PA	3	1964	1978	33	504	115
03015500	Brokenstraw Creek at Youngsville, PA	3	1911	2002	831	487	119
03017500	Tionesta Creek at Lynch, PA	3	1939	1979	603	537	112
03019000	Tionesta Creek at Nebraska, PA	3	1911	1940	1215	515	111
03020500	Oil Creek at Rouseville, PA	3	1934	2002	777	462	113
03021350	French Creek near Wattsburg, PA	3	1976	2002	238	486	119
03021410	West Branch French Creek near Lowville, PA	3	1976	1993	135	449	68
03021500	French Creek at Carters Corners, PA	3	1911	1971	539	461	118
03022500	French Creek at Saegerstown, PA	3	1923	1939	1629	434	116

U.S. Geological Survey gaging station	Location	Low flow region	Record Begin	Record End	Drainage area (km^2)	Mean elevation (meters)	Mean annual precipitation (centimeters)
03022540	Woodcock Creek at Blooming Valley, PA	3	1976	1995	81	443	114
03023500	French Creek at Carlton, PA	3	1910	1925	2585	418	114
03024000	French Creek at Utica, PA	3	1934	1970	2663	418	114
03025000	Sugar Creek at Sugarcreek, PA	3	1934	1979	430	438	111
03025200	Patchel Run near Franklin, PA	3	1966	1978	15	428	109
03026500	Sevenmile Run near Rasselas, PA	3	1953	2002	20	631	114
03028000	West Branch Clarion River at Wilcox, PA	3	1955	2002	163	596	114
03029400	Toms Run at Cooksburg, PA	3	1961	1978	33	478	114
03029500	Clarion River at Cooksburg, PA	3	1940	1952	2090	542	113
03031950	Big Run nr Sprankle Mills, PA	3	1965	1981	19	461	114
03032500	Redbank Creek at St. Charles, PA	3	1920	2002	1368	475	110
03038000	Crooked Creek at Idaho, PA	3	1939	1967	495	388	113
03039200	Clear Run near Buckstown, PA	3	1966	1978	10	822	108
03039925	North Fork Bens Creek at North Fork Reservoir, PA	3	1989	1998	9	684	117
03042200	Little Yellow Creek near Strongstown, PA	3	1962	1988	19	561	118
03047500	Kiskiminetas River at Avonmore, PA	3	1909	1937	4463	534	114
03049000	Buffalo Creek near Freeport, PA	4	1942	2002	355	381	104
03049800	Little Pine Creek near Etna, PA	4	1964	2002	15	338	99
03072590	Georges Creek at Smithfield, PA	4	1965	1978	42	424	112
03072840	Tenmile Creek near Clarksville, PA	4	1970	1979	344	355	99
03074300	Lick Run at Hopwood, PA	4	1968	1978	10	607	119
03078000	Casselman River at Grantville, MD	4	1949	2002	162	787	107
03079000	Casselman River at Markleton, PA	4	1922	2002	989	720	106
03080000	Laurel Hill Creek at Ursina, PA	4	1920	2002	313	674	117
03082200	Poplar Run near Normalville, PA	4	1963	1978	24	591	114
03082500	Youghiogheny River at Connellsville, PA	4	1910	1925	3434	690	116
03084000	Abers Creek near Murrysville, PA	4	1950	1993	11	353	99

U.S. Geological Survey gaging station	Location	Low flow region	Record Begin	Record End	Drainage area (km^2)	Mean elevation (meters)	Mean annual precipitation (centimeters)
03084500	Turtle Creek at Trafford, PA	4	1922	1952	145	343	99
03093000	Eagle Creek at Phalanx Station, Ohio	4	1928	2002	253	319	98
03100000	Shenango River near Turnersville, PA	4	1913	1922	394	331	106
03102000	Shenango River near Jamestown, PA	4	1921	1934	469	334	105
03102500	Little Shenango River at Greenville, PA	4	1915	2002	269	368	103
03103000	Pymatuning Creek near Orangeville, PA	4	1915	1963	438	320	100
03104000	Shenango River at Sharon, PA	4	1911	1938	1575	336	102
03104760	Harthegig Run near Greenfield, PA	4	1970	1981	6	385	104
03106000	Connoquenessing Creek near Zelienople, PA	4	1921	2002	922	363	99
03106500	Slippery Rock Creek at Wurtemburg, PA	4	1913	1969	1031	398	103
03108000	Raccoon Creek at Moffatts Mill, PA	4	1943	1956	461	339	96
03109500	Little Beaver Creek near East Liverpool, OH	4	1917	2002	1285	345	94
04213000	Conneaut Cr at Conneaut, OH	3	1924	2002	453	307	107
04213075	Brandy Run near Girard, PA	3	1988	2002	12	274	109

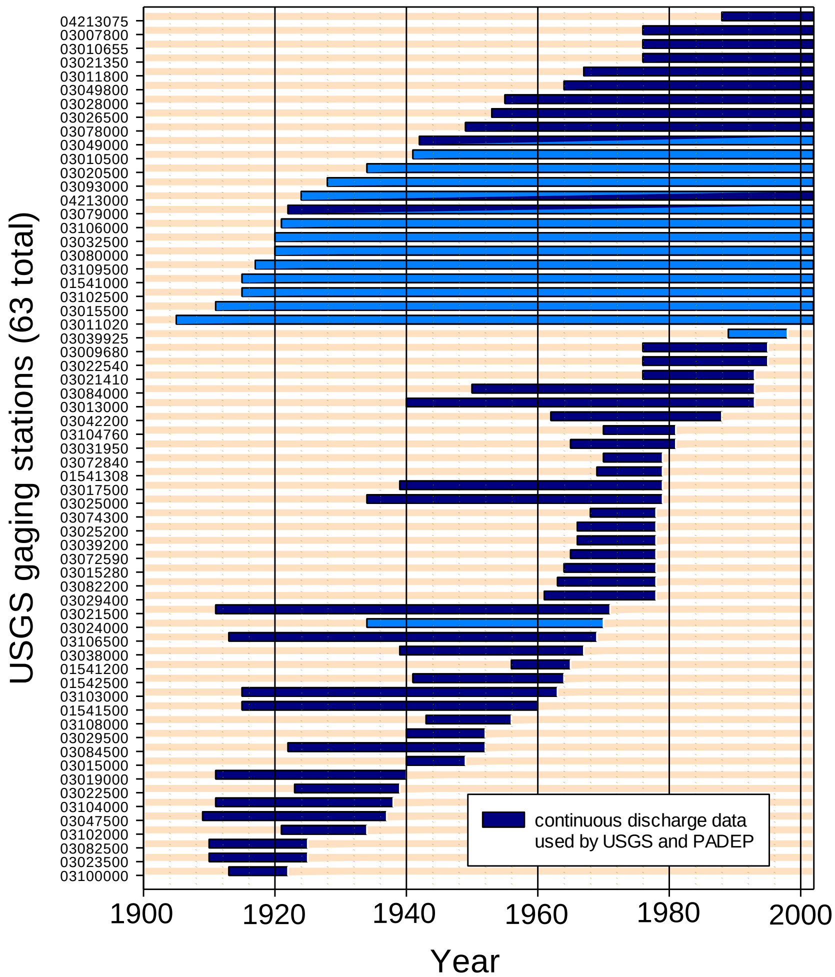


Figure 20: Data coverage of the minimally-impacted flow records corresponding to the 63 USGS streamgages used in this study between 1900 and 2002. Lighter blue bars indicate the existence of 60 or more years of uninterrupted stream flow data in the flow record.

Instantaneous flow measurement errors

The implementation of passby flow standards requires an operator to determine instantaneous flow at the point of withdrawal for comparison with the standard prior to taking water. Operators may use scaled index gage information, following the same criteria mentioned in the text. When an index gage is unavailable, the common practice is to have a staff gage installed at the point of withdrawal. This usually involves 3-5 field measurements to estimate the stage-discharge relationship relative to a graduated marker installed in the streambed from which instantaneous discharge can be approximated from a visual observation of water height. Large and unpredictable errors in the instantaneous discharge that operators use for compliance are expected for index gage scaling and staff gage methods for two reasons. First, the field measurements of stage and discharge are error prone; under non-ideal conditions, including low-flow, the error may approach 20% (*218*). This is especially true for shallow and low-velocity streams and creeks (*219*). The influence of field measurement error on the accuracy of the stage-discharge relationship can be large when there are few measurements.

The second cause of error in instantaneous discharge data is streambed instability. For alluvial streams, the stage-discharge relationship may shift frequently, and the shifts vary in direction, magnitude, rate of change, and duration (*220, 221*). Changes to the relationship between stage and discharge can occur by natural processes, such as the flushing of sediment out of the channel or the buildup of fallen foliage on the measurement control, as well as by human activity. For a particular streamgage, USGS technicians routinely use field observation and calibration measurements to identify these changes and then update the rating curve, which includes all segments and adjustments to the stage discharge relationship (*222*). From the rating curve, gage height measured at the streamgage is automatically converted to discharge. Despite the continuous process of adjustments and corrections, the time between measurements is around seven weeks, and there is a lag in making needed corrections to the rating curve. This means that operators are likely to be using instantaneous flow data derived from an out-of-date rating curve.

A simple analysis, comparing provisional daily discharge data to the later approved records for eight months (October–May) of the discharge record at 29 active streamgages (Table 15) was conducted. The provisional record matched the approved record at two streamgages, but in others a persistent upward and downward biases was found in the provisional data. Daily discharge values in the approved record differed from those in the provisional record around 60% of the time, suggesting problems with use of instantaneous measurements in the field for evaluating stream flow. The stage-discharge relationship is commonly disrupted in January and February by the buildup of debris and ice, so a large portion of the discharge data during the winter months was marked as "estimated" (*223*). Instantaneous flow data from these periods may be unreliable.

Table 15: The percentage of daily discharges in the USGS approved record that were later marked estimated or corrected, for 29 active streamgages used in this study.

	2009			2010				
	10	11	12	1	2	3	4	5
Estimated	2%	1%	17%	59%	78%	19%	1%	1%
Corrected	42%	48%	54%	67%	74%	57%	58%	62%

The change between the provisional and approved records was usually within plus or minus 10%, but the provisional records examined here is only a snapshot in time, and the representativeness of these data cannot be assured.

Ecodeficit calculations

Figure 21 graphically illustrates the computation of ecodeficit for typical and low flows in the month of September at Laurel Hill Creek. It contrasts the original September flow duration curve with the FDC that would result from the 2000 m^3/km^2 monthly water demand scenario and a passby flow equal to 5^{th} percentile of 10-year Q60 sample set. The monthly ecodeficit is calculated as the area between the original and altered FDC divided by the total area under the original FDC. The ecodeficit was calculated for typical flows (between the 10% and 75% percentile) and for low flows, between 75% and 99% percentiles (*207-209*).

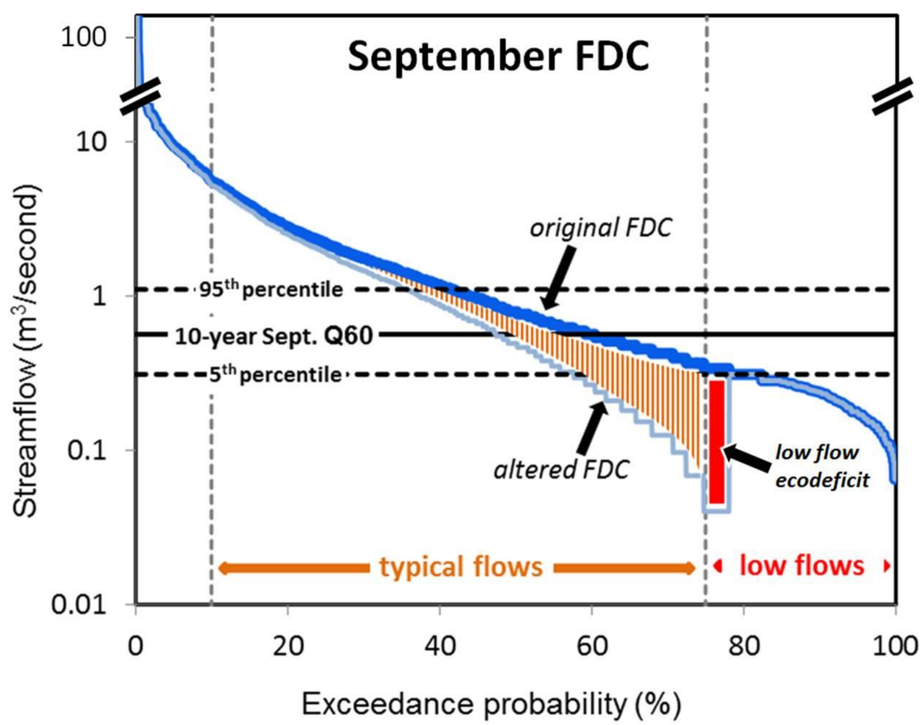


Figure 21: Graphical illustration of the concept of ecodeficit resulting from underestimation of Q60 for the month of September at the Laurel Hill Creek streamgage under a 2,000 m^3/km^2 water demand scenario (which is approximately equivalent to removing 600,000 m^3 or 160 million gallons over the month). The average 10-year September Q60 and the 5^{th} and 95^{th} percentile estimates are shown. Between the 75% and 99% exceedance probabilities, the difference in area under the original and altered FDCs divided by the total area under the original FDC is the low-flow ecodeficit (red).

Figure 22 shows the results of the three water withdrawal scenarios and the three cases of underestimated passby flow statistics for “typical” flows.

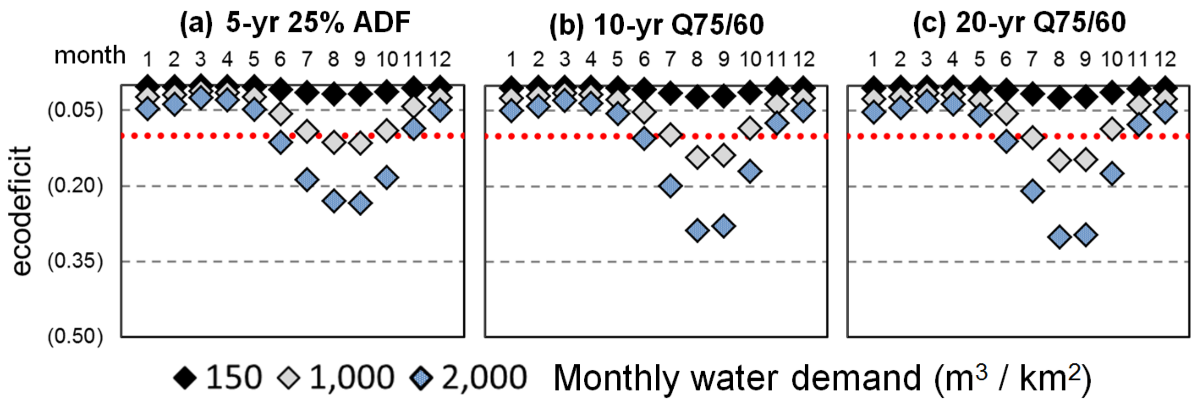


Figure 22: The average monthly typical flow ecodeficits estimated for the 14 USGS streamgages for monthly water demands of 150, 1,000, and 2,000 m^3/km^2 subject to underestimated (5th percentile) values of (a) the 5-year 25% ADF, (b) the 10-year Q75/60, and (c) the 20-year Q75/60. The Nature Conservancy threshold of 0.20 (20%) is indicated by the red-dashed line.

Chapter 4: Economic regulatory incentives for plugging and abandonment of shale gas wells[2]

Introduction

Disturbance of the surface environment and subsurface geological strata is a necessary outcome of producing shale gas. Surface disturbance is caused by the construction of well pads, impoundments, access roads, and pipelines. Reclamation of the disturbed surface occurs in two stages. Shortly after a well (or multiple wells on a pad) begins production, the size of the well pad is reduced, and any impoundments for storing water or waste are removed. Full reclamation, known as plugging and abandonment, does not occur until after all wells on a pad are permanently taken out of production, because site access is necessary for routine maintenance and removing produced water (brine that comes up with gas).

If a well site is not properly reclaimed after abandonment, the well pad and access roads may cause permanent changes to the natural environment. The deterioration of erosion control features increases siltation, which results in the loss of nutrient-rich topsoil and increased sedimentation of nearby surface waters, impairing natural habitats of aquatic species (*224-226*). Compared to natural forest clearing occurrences (e.g. fire), the recruitment, growth, and mortality rate of native plant species at reclaimed oil and gas well sites in boreal forests was found to be significantly worse (*227*). Without restoration of topsoil and proper revegetation, the regeneration of natural habitat will be delayed and the environmental impacts of forest fragmentation, including loss of biodiversity and introduction of invasive species, will be

[2] Austin L. Mitchell and Elizabeth A. Casman, Economic Incentives and Regulatory Framework for Shale Gas Well Site Reclamation in Pennsylvania, Environmental Science & Technology 2011 45 (22), 9506-9514

exacerbated. The adverse effects of forest fragmentation on the nesting success of migratory birds have been documented (*228*), and the impacts extend to other plant and animal species dependent on shade, humidity, and tree canopy protection characteristic of deep forest environments in the region (*9, 229*). The construction of well pads, water impoundments, and access roads is projected to disturb 129,000 to 310,000 acres of forested land in Pennsylvania (*9*). In northern Pennsylvania forests, where largest blocks of public forests exist, the potential for lasting forest fragmentation and associated environmental impacts could negatively affect economic interests related to timber management, game, and tourism (*229*).

To reach the Marcellus Shale formations, wellbores usually transect more than two kilometers of geologic strata, including fresh and saline aquifers and shallow gas-bearing formations. Shale gas wells need to be plugged to prevent environmental damage caused by the disturbance of the subsurface, namely the movement of oil, gas, and brine to the surface and between geologic formations connected by the wellbore. General plugging procedures in most states, including Pennsylvania, begin with the removal of steel production casing that extends from the surface to producing formations for scrap value. Next, a series of cement plugs will be installed in the wellbore to isolate freshwater and saline aquifers and gas producing formations (Figure 23) (*230*).

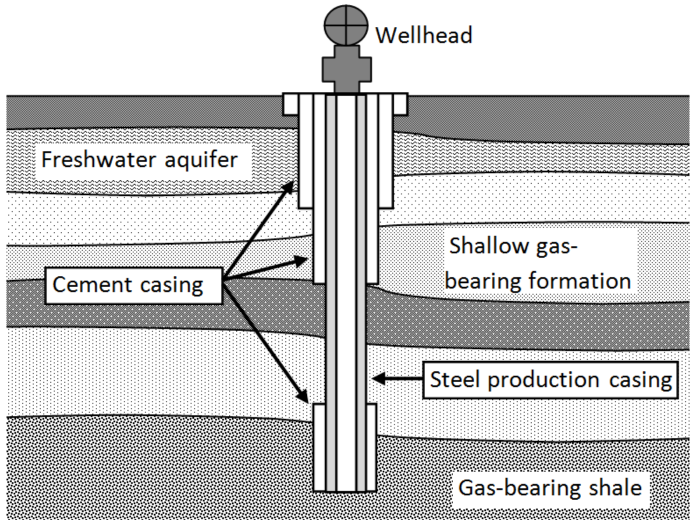


Figure 23: Simple representation of a vertical shale gas well's anatomy. Layers of cement and steel casing are used to isolate production zones from freshwater aquifers. To properly close a shale gas well, the wellhead and steel production casing are removed and cement plugs are installed to prevent fluid movement in the wellbore and annulus. These steps also apply to horizontal shale gas wells. This diagram is not drawn to scale.

Unplugged wells may provide a direct pathway to the environment for fluids in the wellbore, (*231*) which results in ecological harm, property damage, and surface and ground water contamination. Additional pathways in the annulus (an industry term for the space between two concentric objects, such as between the wellbore and casing or between casing and tubing) may develop that would allow oil, gas, and brine to move vertically across geologic formations and contaminate groundwater. Substances dissolved in the brine include those that occur naturally in the shale formations (some radioactive), but the brine could also include chemicals used in the hydraulic fracturing process (some toxic). Also upwardly migrating gas, known as stray gas, represents an explosion hazard if not properly vented away from buildings and drinking water wells (*32, 232, 233*).

The risk that annular pathways will develop increases over time as chemical, mechanical, and thermal stresses causes deterioration of well structures and components. Failure modes of improperly abandoned wells (defined here as non-producing wells not in compliance with Pennsylvania plugging requirements or inactive status rules) include the formation of cracks in the cement casing or packers, corrosion of steel production casing, faulty valves, and leaking temporary plugs or surface caps (*231, 234-238*). Properly performed, the plugging process reinforces existing casing and seals and prevents fluid movement in the wellbore, which may retard the deterioration of vital well components and structures. Therefore, prompt plugging once a shale gas well becomes uneconomic may reduce the risk of negative environmental and human health impacts (*234, 235*), while also avoiding additional plugging costs that may be incurred if the mechanical integrity of a casing has been compromised (*239*). However, the risk of failures leading to fluid migration pathways still exists after a well has been plugged and increases with time (*231, 235-237*).

The impacts and remediation costs resulting from gas migration and groundwater contamination due to failures at unplugged and improperly abandoned gas wells is well documented in Pennsylvania and elsewhere (*32, 233, 240-242*). Property values can be negatively affected if gas wells contaminate groundwater used for drinking (*243-245*). Moreover, the presence of an improperly abandoned gas well may prevent landowners from using their property for other purposes (*246*). Stray gas, which is mostly methane, is also a potent source of greenhouse gas emissions (*247*).

The Saudi Arabia of natural gas and the Swiss cheese of Appalachia

Approximately 350,000 conventional oil and natural gas wells have been drilled in Pennsylvania since the 1859 discovery of oil in Titusville (*232*). Many of these legacy wells that are no longer producing oil or gas were never properly plugged. Some leak gas, oil, and/or brine into freshwater aquifers and the surface environment (*32, 248*). To address issues of pervasive non-compliance with plugging and abandonment requirements, a bonding requirement was established in Pennsylvania's Oil and Gas Act of 1984. All wells with oil or gas production after 1979 were covered. The legislative intent was for the bonding requirements to cover the full cost of plugging and abandonment so that the State could be made whole in the event of owner failure to perform the reclamation. In 1985, Pennsylvania started plugging oil and gas wells lacking a legally responsible owner, known as orphan wells, and supported these activities with fees on new oil and natural gas well permits ($200 and $50 per well for the Orphan Well Plugging Fund and Abandoned Well Plugging Fund, respectively), monies collected for regulatory violations, and grants distributed by Pennsylvania's taxpayer-funded Growing Greener program (*249*). From 2007 to 2008, the most recent years for which data are available, a total of $1,066,000 in Growing Greener grants were awarded to reclaim orphan and abandoned wells (*250, 251*). Before the current shale gas boom, the Pennsylvania Department of Environmental Protection (PADEP) estimated that at 2004 funding rates it would take around 160 years to plug all the existing orphan wells in the Commonwealth (*232*). Additional funds are now being directed to well plugging activities with the passage of Act 13 (Omnibus Oil & Gas Legislation) in 2012, which established a grant-making entity (the Marcellus Legacy Fund) focused on issues associated with orphan wells (*252*).

Costs of site restoration and shale gas well closure

Pennsylvania's 1984 Oil and Gas Act defines a natural gas operator's drinking water, site restoration, and well closure responsibilities. Once a well is abandoned, the owner has 12 months to properly plug it and restore the well pad to its previous condition. Restoration of the production well pad (which typically covers more than 1 hectare (*9, 11, 253*)) may involve re-grading of land, removing access roads and impoundments, restoring top soil, planting native flora, or other necessary restoration required for compliance with Pennsylvania's Clean Streams Law of 1937 (*254*). Operators must also remove all equipment used in the production of gas as part of the well abandonment process. This equipment includes the production casing (innermost steel casing that extends down to the production zone), Christmas tree (a grouping of pipes, valves and fittings used to control the flow of gas from a well), dehydrator, compressor, and tank battery.

The cost to plug a deep shale gas well has not been formally estimated by the PADEP, however, it is understood that the cost to plug a well depends primarily on its measured depth (full length of wellbore including horizontal portions). Plugging costs increase when the condition of the wellbore is poor or access to the site is difficult. For orphan oil and gas wells in southwestern Pennsylvania, the PADEP estimates the total cost to plug and restore the site of a well approximately 914 meters (3,000 feet) in depth averages $60,000, but per well reclamation costs have also exceeded $100,000 (*239*). Reclamation costs of wells drilled into the Devonian shale (Marcellus, Utica, and Upper Devonian), which range from 1,524 to 2,744 meters deep (*170*), will clearly be greater. Using reclamation data from 255 orphan wells in Wyoming, Andersen and Coupal (2009) estimated the relationship between reclamation costs and depth

(*255*). They estimated that total reclamation costs (well plugging, site restoration, and equipment removal) were approximately $34.45 per meter ($10.50 per foot). They also noted that economies of scale exist when more than one well is on each well pad, which is the norm for wells in the Marcellus Shale. However, if all wells on a pad are not decommissioned at the same time, opportunities for economies of scale would be limited to the eventual surface restoration. Summarizing data from approximately 1,000 individual well completion reports catalogued by the Pennsylvania Department of Conservation and Natural Resources (*170*), the average measured depth of hydraulically fractured shale gas wells completed in Pennsylvania during 2010 was approximately 3,254 meters (10,675 feet). Thus, for a single well, at $34.45 per meter, the average reclamation cost for a well in the Marcellus Shale will be in the vicinity of $100,000. However, in some cases the costs for plugging and abandonment of a shale gas well in Pennsylvania have been substantially higher. For instance, in 2010, Cabot Oil & Gas Corporation estimated that it spent $2,190,000 to properly abandon three vertical Marcellus Shale gas wells in Susquehanna County, Pennsylvania – about $700,000 per well (*256*).

Pennsylvania bonding requirements on private lands do not incentivize reclamation

Issues of operator insolvency due to the boom and bust cycles of oil and gas development complicate efforts to hold liable parties responsible and provide for timely environmental reclamation. In theory, requiring that operators post bonds prior to drilling bolsters traditional liability rules by incentivizing compliance (*257*). Pennsylvania only releases bonded monies one year after the PADEP deems regulatory requirements associated with reclamation have been satisfied. If the level of bonding is set less than the associated reclamation costs, companies could be tempted to pursue strategies that avoid their liabilities.

Oil and gas bonding requirements vary across states and on federal lands, but most have established minimum bonding levels (blanket or for individual wells) (*246*). In general, the dollar amount of state and federal bonds for oil and gas wells often do not reflect expected reclamation costs. The full effect of this imbalance has not yet been felt because oil and gas wells may have long life spans (up to 50 years, which can be prolonged further on paper via regulatory allowances), and bonding requirements are relatively new (*257*).

Pennsylvania's experience with bonding of coal mining sites may be indicative of what to expect. From 1985 to 1999, bonds for surface mining permits covering approximately 10% of total acreage were forfeited (*258*). Since the cost to reclaim a mine in most cases was higher than the amount bonded, funding to bring abandoned mine lands into compliance has generally been inadequate (*258*-*260*). In 1986, only 33% of acreage covered by forfeited bonds had been reclaimed, according to a U.S. General Accounting Office study. The discrepancy was attributed to inadequate funding from forfeited bonds and legal delays in bond forfeiture (*260*). Following a lawsuit and increased Federal scrutiny thereafter, Pennsylvania modified its regulatory framework related to the reclamation of abandoned mine lands (*259*). Pennsylvania now requires mine operators to perform site-specific estimation of reclamation liabilities to ensure posted bonds cover the full cost of reclamation (*261*).

Under Act 13, shale gas operators in Pennsylvania must post either a bond of $10,000 for each well or a blanket bond of $600,000 to cover all the wells they drill in the state. This represents a small increase from the dollar amount required in 1984 ($2,500 and $25,000 for individual and blanket bonds, respectively), which until 2012 had not been adjusted despite statutory provisions that empower the Environmental Quality Board to adjust the level of bonding to match projected reclamation costs every two years. A bond of $10,000 is inadequate to cover the costs to plug a deep shale gas well and restore the land (total cost to do this is between $100,000 and $700,000). The inadequacy of the blanket bond is even more pronounced, as many operators are expected to drill thousands of wells. For example, Chesapeake Energy, operating in a joint venture with Statoil, plans to drill up to 17,000 shale gas wells in Appalachia over the next 20 years (*262*).

The Oil and Gas Act prohibits private landowners from securing financial assurances from the operator independent of Pennsylvania regulations. The situation is different on Pennsylvania's state-owned land. Pennsylvania includes a condition in all of its lease agreements for drilling in state forests that requires operators to submit additional individual well bonds. The dollar amount required scales with the measured depth, so operators in state forests are required to post bonds of $50,000 to $100,000 per well drilled (*263*).

It is important to note that the substantial bonds required in drilling leases in state forests did not preclude a successful lease auction – proceeds of $128 million far exceeded original expectations of $60 million (*264*). This suggests that bonds in the $100,000 range are not prohibitive for large exploration and production companies, though they may be an obstacle for smaller firms.

Transferring assets shifts environmental liability

To sustain current levels of production, the shale gas industry needs to constantly drill and complete new wells because gas production rapidly declines in the first few years of production. Figure 24 shows a type curve published by a Marcellus Shale operator, EQT Production (*265*). A type curve is a gas production curve modeled from initial and historic production data and reservoir characteristics. The precipitous decline in the production rate of gas is typical of deep shale gas wells in Pennsylvania and elsewhere. (Re-fracking is a process that can be used to increase production in a declining well. Because there are no reliable data published on this practice in Appalachia it is excluded from this analysis.)

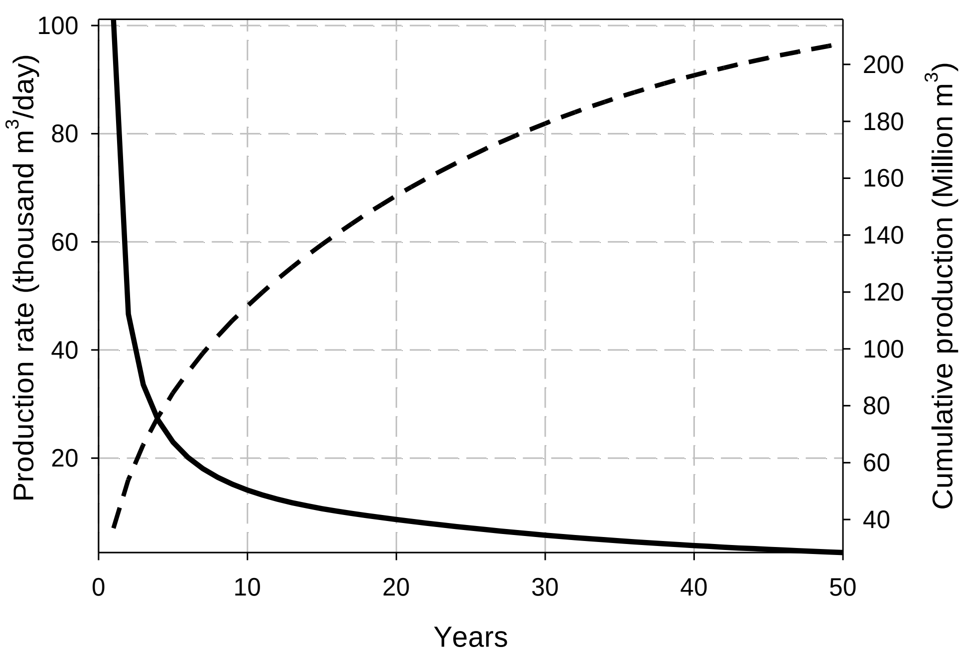


Figure 24: Expected gas production rate (solid line) and cumulative production curve (dashed) for EQT Production's Marcellus Shale operations (*265*).

Industry economics are dominated by high initial gas production rates. For a typical well, assuming a constant price of $176.6 per thousand cubic meters of gas ($5/Mcf) and a $5.3 million cost to drill and complete a new well (*265*), the internal rate of return (IRR) asymptotes near 79% after the seventh year, after which production revenue dwindles compared to that of the initial years. Assuming a 10% discount rate, 81% of the net present value (NPV) of gross revenue would be realized in 10 years. Compared to the potential revenue from gas sales, the present value of long-term shale gas liabilities, which are discounted 40-50 years, has negligible impact on near-term accounting. The problem of failing to internalize reclamation liabilities emerges when the liabilities begin to exceed the current asset value.

The steep decline in production may drive divestment of shale gas assets by primary exploration and production companies well before the expected closure of a shale gas well. The transfer of marginally-producing assets to smaller independent operators or surface owners is common practice in the oil and gas industry (*266-268*). Sometimes, surface owners take ownership of a marginally producing well for household use. In such cases, the Oil and Gas Act permits oil and gas asset transfers as long as the prospective owner satisfies the applicable bonding requirements. In Pennsylvania, there exists no formal regulatory mechanism to prevent fully-bonded owners from assuming gas production assets with reclamation liabilities substantially above their own financial means. Large liabilities covered by limited resources could lead to large-scale default, similar to the situation that spawned Pennsylvania's pervasive abandoned acid mine drainage and orphan well problems (*269*).

In Pennsylvania and other U.S. states, individual and blanket bonds may be satisfied using a number of financial instruments and often do not even require monies to be transferred. Requiring only the demonstration of assets is common, especially for large operators. When an operator cannot demonstrate sufficient assets to cover liabilities, third party backing, usually in the form of a surety bond, may be obtained for a percentage of the bond's face value. Since surety companies or banks underwriting the bond are liable if an operator is unable to perform reclamation, bond rates are set according to an individual operator's risk of insolvency (*257*).

Today's low bonding levels make it possible for hundreds of independent operators to satisfy Pennsylvania's blanket bonding requirements (*270*). These operators are capable of producing marginal amounts of oil and gas economically, which allows them to maximize potential economic benefits by extending the productive lifetime of oil and gas wells (*271*). The ability to transfer well ownership to independent operators benefits the industry, but a potential consequence of increasing bonding minima could be that smaller operators may face steep risk premiums or not qualify for third party backing and be excluded from participation.

Primary exploration and production companies sometimes rely on divestment of existing assets to fund new drilling operations. Blocking independent operators from the market may force these companies to temporarily abandon their uneconomic wells and apply for inactive status instead. In Pennsylvania, non-producing wells may be granted inactive status for a period of five years, but to be granted an annual extension the operator only has to declare regulatory compliance and the capacity to produce gas in the future from the inactive well. Inactive status and similar provisions in other states grant operators the ability to temporarily abandon a gas well until technology advances or favorable gas prices improve the economics of production, though in practice the decision to re-open a well is expected to be dominated by reclamation and other liabilities (*234*).

Inactive status could be used to defer the costs of reclamation indefinitely. According to PADEP records, almost 17,000 conventional oil and gas wells did not report or produce oil or gas for three consecutive years (2007-2009), and were listed as active at the end of 2009.While it may be the case that many of the operators of these wells simply failed to report production, poor compliance with reporting requirement prevents the PADEP from enforcing plugging requirements or administering the inactive status program. In 2009 alone, only 38% of the Commonwealth's conventional oil and gas wells reported production, which indicates a majority of the wells drilled in Pennsylvania may represent environmental liabilities as opposed to a source of revenue (*270*). Incentives (fines) are needed to improve compliance with production reporting requirements, though reporting alone will not close this loophole.

The delay between production and reclamation temporally separates revenue generation from the future liabilities. Others have recognized this undesirable trend and instituted remedies. Growth in the number of non-producing (idle) wells in Alberta and Saskatchewan led these two Canadian provinces to implement a Licensee Liability Rating Program as a measure of insolvency risk and to minimize state financial exposure to orphan wells. The program requires individual operators to provide financial assurance equivalent to the difference between the operators' assets (active wells and production facilities) and liabilities (inactive wells and abandoned assets) (*272, 273*). Some U.S. states offer tax breaks to promote marginal well production, while others require additional bonds or levy annual fees for inactive wells to incentivize new production or plugging, and to fund compliance monitoring (*246, 271*).

Regulatory policy and financial assurance options

When bonding requirements are smaller than expected liabilities, there is a financial incentive to not comply with reclamation requirements. Individual well bonding requirements that match reclamation costs would remedy this situation, especially with the blanket bonds, where misalignments with reclamation costs can be huge. Eliminating the blanket bond would be a common sense first step for Pennsylvania. However, simply increasing the bond requirement to match reclamation costs may not be the best alternative because more operators will need to obtain third party backing. In theory, reliance on third party backing favors operators that manage assets and liabilities effectively since the underwriting firms would assess the risk of insolvency of individual operators. However, the same may not be true for third party backers. Insolvency of these financial firms is a real concern and the effects may be large (*257, 274*).

Furthermore, bonds are inherently inflexible to changes in the cost of performing reclamation, to the economics of gas extraction when wells start to lose pressure, and the way financial risk is shared in the industry. This is problematic if reclamation costs deviate dramatically from the average. For instance, following methane migration into the aquifer supplying drinking water to fourteen households in Dimock, Pennsylvania, the estimated costs for individual water filtration units and supply replacement via permanent pipeline were approximately $8,000 and $800,000 per household, respectively (*256, 275*). Underwriting firms will only market surety bonds when the amount and term of liability are strictly defined (*257*), so bonds are not well suited to cover uncertain liabilities. Bonds would also fail to provide funding for maintenance and monitoring of plugged and abandoned wells and the potential environmental issues that may arise post-reclamation. After the release of a bond, recovery of additional environmental costs would require aggrieved citizens or the State to pursue civil action. The State may also block the issuance of new permits to operators with outstanding reclamation liabilities, but for operators without ongoing interests in Pennsylvania, this enforcement mechanism will be limited.

Alternatives to bonds

To pay for the long-term treatment of acid mine discharges, coal mine operators in Pennsylvania may establish trust accounts under contract with the State. Funding requirements are based on operator estimates of the present value of capital costs and operating expenses of pollution control projects, which depend on the inflation rate and the expected growth of the trust account. As irrevocable beneficiaries of the trust, the State will reimburse coal mine operators one year after the performance of work, or in the case of non-performance, the State may use accumulated funds to do the work (*276*).

If reclamation trust accounts were to be used for the shale gas industry, it would be the responsibility of the operator to determine current (time zero) reclamation costs as part of the drilling permit and the responsibility of the state to approve that figure. If the trust accounts were tied to individual wells rather than pooling them, timely plugging would become independent of the solvency of the last operator.

For the mining industry, trusts are designed so that they will be fully funded one-year after production ends. The size the trust is estimated from Equation 4, which shows the calculation for the present value of reclamation costs.

$$PV = \left[\frac{RC}{(1+[E-I])^t} \right] * (1+Vol) \qquad (4)$$

where:

RC = Estimated cost of reclamation in current dollars
E = Expected annual earning on investments in trust
I = Inflation Rate
Vol = Volatility premium, proportional to amount invested in stock market
t = Time in years, duration of production

For the shale gas industry, the contract between the State and individual operator would specify the firm responsible for managing the trust account and investment strategy. An inflation rate of 3.1%, bond yield of 5.25%, and market return of 11.2% are recommended by the PADEP for Equation 4. At most, 80% of the trust may be invested in stock. A 20% volatility premium is required for the portion of the trust invested in stock (*276*). It is the responsibility of the PADEP to ensure an operator's inflation, bond yield, and market return assumptions reflect current conditions. This contract would also detail the irrevocable rights held by the State to claim monies held in the trust.

Three potential mechanisms to fund well reclamation costs are estimated using Equation 4: cash bond, severance tax on gas production, and a discounted pre-drilling fee. The properly sized cash bond represents a "no risk" scenario for Pennsylvania because operators would be required to deposit the full cost of reclamation as a precondition for drilling permit approval.

Compared to the other forms of bonding allowed by the PADEP, the State Treasurer would manage the bonded monies and the risks associated with operator or third-party default or insolvency would be eliminated. A severance tax on gas production would gradually collect and reinvest monies to reach the future value of reclamation. Pennsylvania's Governor, Tom Corbett, opposes levying taxes on the natural gas industry, but has supported a one-time, per well fee to pay for local impacts of the natural gas industry. To fund a reclamation trust via a discounted pre-drilling fee, it was assumed that the fee would need to be assessed in an amount equal to the present value of expected reclamation costs at the time of well closure. The severance tax and pre-drilling fee represent delayed funding mechanisms, so the annual growth and security of the trust as well as the productive lifetime of a shale gas well are important variables. The cost to perform reclamation is compared to funds accrued in a reclamation trust by a severance tax (calculated for two different anticipated well lifespans) and a pre-drilling fee in Figure **25**. To fully fund a reclamation trust by year 16, a pre-drilling fee of $65,975 and a severance tax of $0.87/TCM ($0.25/Mcf) collected for five years would need to be assessed. A severance tax of $0.15/TCM ($0.004/Mcf) on the first five years of production would be assessed if full funding of the trust is not required until year 51. The cash bond option is not graphed because it is equivalent to the inflated reclamation cost each year. The options are fully funded when they intersect the reclamation cost line. If the well is abandoned before the reclamation trust is whole, the difference between the accumulated funds and the inflated reclamation costs will be the shortfall.

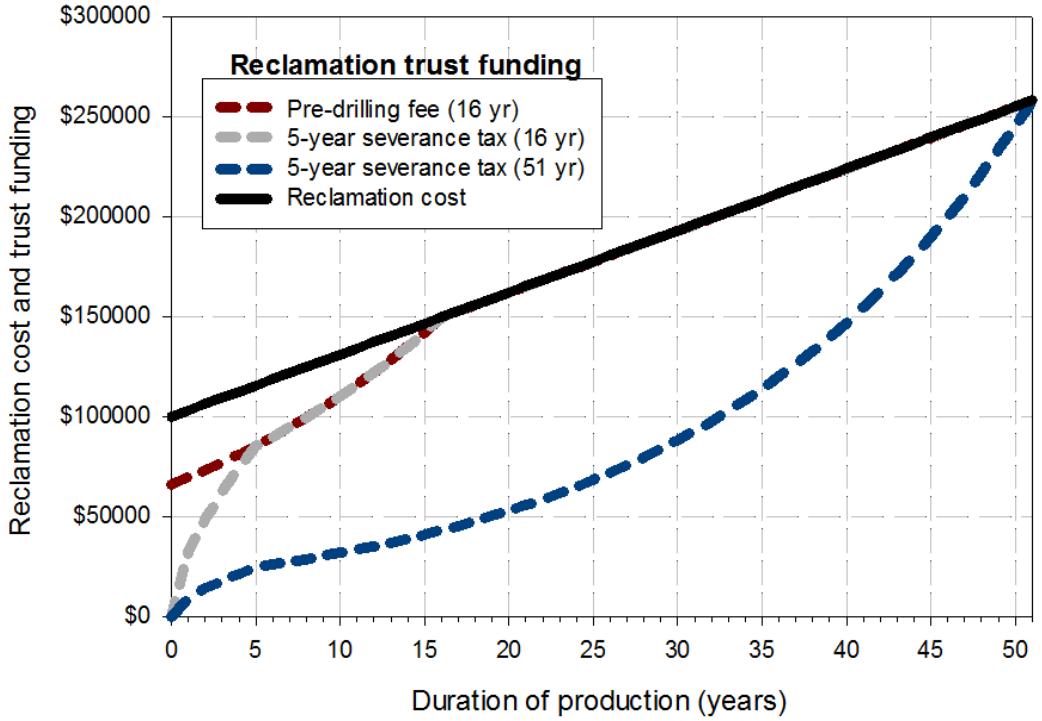


Figure 25: Comparison of financial assurance mechanisms for funding a reclamation liability costing $100,000 at time zero. Assumptions: gas is produced according to the EQT Production type curve (Figure 24); the inflation rate is 3.1%; and monies invested in the trust have an assumed annual return of 5.25%, following PADEP guidance for bond yields (*276*). The "no risk" cash bond option is not shown as it is equal to the cost of reclamation. The funds collected by a pre-drilling fee and severance tax collected for five years are contrasted. Delayed collection options run the risk of collecting insufficient funds for reclamation of the well if the number of productive years is less than the number of years used to determine present value of reclamation costs. At any given year, the funding shortfall is measured as the difference between the projected reclamation cost line and the respective delayed option line.

No empirical evidence exists to suggest the economic lifetime of a shale gas well will reach generic industry predictions of 40-50 years. Well productivity and the economics of shale gas production have equal weight in an operator's decision to keep a well open. The use of unrealistic expectations of well economics has implications for the application of delayed funding mechanisms and risks underfunding reclamation trust accounts. Figure 25 shows that even if a 15-year lifetime is assumed (reclamation costs discounted from year 16), the difference between the reclamation cost and the funding levels in the trust are substantial for wells abandoned sooner. For the purpose of estimating reclamation costs, it would be wise for Pennsylvania to require that reclamation costs by funded within 10 years, regardless of the actual life span of the well.

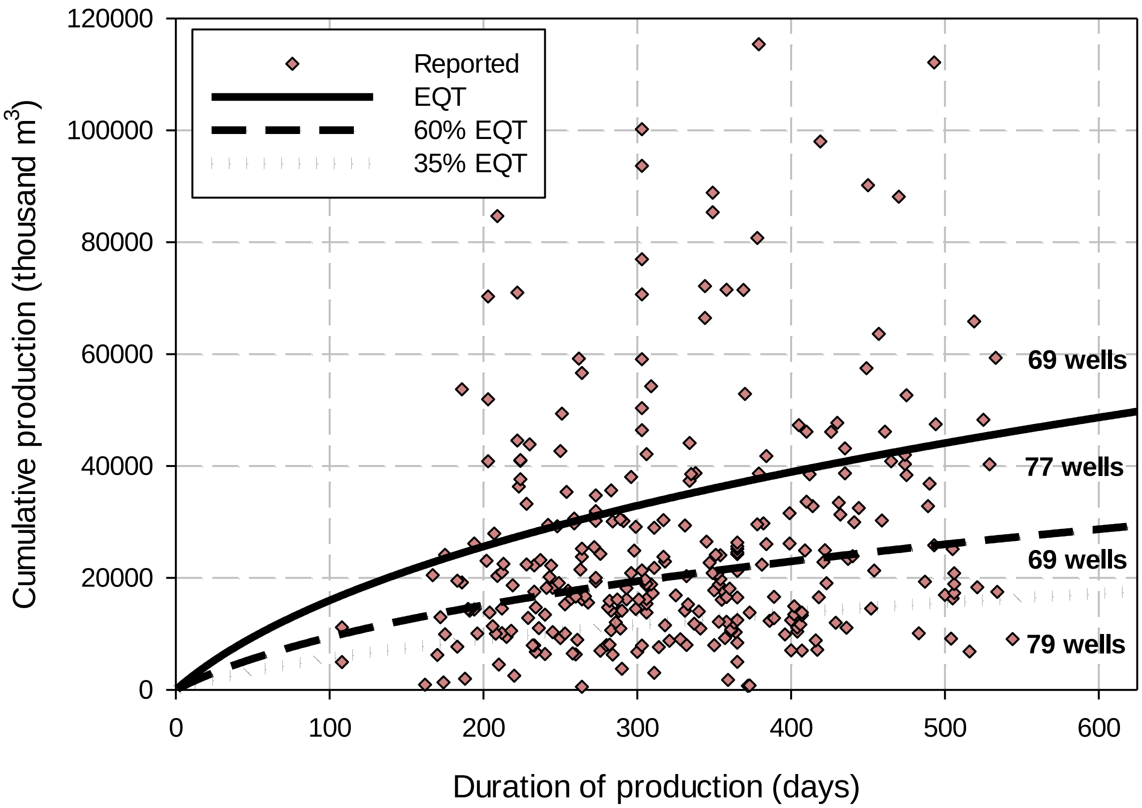


Figure 26: Reported cumulative production of 294 individual horizontal Marcellus Shale gas wells that began producing after 1/1/2010(*270*). Three continuous cumulative production curves are modeled: EQT Production's type curve (Figure 24), a 60% EQT, and 35% EQT. Cumulative production predicted by the 60% EQT and 35% EQT curves is exceeded by 50% and 75% of horizontal Marcellus Shale gas wells, respectively.

Actual production will deviate from industry type curves. Figure 26 shows the cumulative production from horizontal shale gas wells in Pennsylvania that began producing gas from January 2010 through July 2011 compared to the EQT Production type curve (Figure 24). While nearly a quarter of the wells exceeded the EQT curve, half of the wells produced less than 60% of the EQT curve and 25% of the wells produced 35% or less of the EQT estimate. The variability in cumulative production indicates that industry type curves should not be used to set the terms of financial assurance policy. If a 5-year severance tax is calculated from EQT Production's type curve and applied to the cumulative production of all the wells in Figure 25, independent of the tax rate, the amount of money collected in a trust would only be 62% of the target funding level, assuming that excess funds are returned to the operator.

The impact of these regulatory options on the industry bottom line

From the point of view of industry finances, the different funding mechanisms have similar impacts on the internal rate of return (IRR) of a producing well, even if total production is low. Table 16 contrasts the IRRs resulting from implementation of (1) the current bond requirement ($10,000), (2) a cash bond equivalent to the reclamation cost, (3) a pre-drilling fee, and (4) a 5-year severance tax. Revenue from production for 50 years was assumed, but a 10-year funding timeline was established to minimize the risk of underfunding the reclamation trust.

Table 16: Gross revenue internal rate of returns (IRR) incorporating the implementation cost of financial assurance mechanisms. Drilling and completion cost of $5.3 million and $176.6/TCM ($5/Mcf) price of gas is assumed. The pre-drilling fee and 5-year severance tax are calculated to fully-fund the reclamation trust by the start of year 11. Two target reclamation costs are contrasted, $100,000 and $700,000. The pre-drilling fees are $76,000 and $535,000 for targets of $100,000 and $700,000, respectively. A severance tax rate of $1.01/TCM ($0.029/Mcf) is required for reclamation cost of $100,000 and the EQT production curve. The rate increases to $20.01/TCM ($0.57/Mcf) for reclamation cost of $700,000 and the 35% EQT production curve. TCM = thousand cubic meters. Mcf = thousand cubic feet

Reclamation cost	Gas production curve model	IRR with current bond	IRR with "no risk" cash bond	IRR with pre-drilling fee	IRR with 5-year severance tax
$100,000	EQT	78.7%	76.7%	77.1%	78.1%
	60% EQT	34.3%	33.2%	33.5%	33.8%
	35% EQT	13.2%	12.7%	12.8%	12.9%
$700,000	EQT	78.7%	65.6%	68.4%	74.3%
	60% EQT	34.3%	27.6%	29.0%	30.7%
	35% EQT	13.2%	10.2%	10.8%	11.0%

Though these are rough calculations based on simple assumptions, Table 16 shows that levying a pre-drilling fee and small severance tax on the first five years of production would quickly fund a trust account with minimal impact on the project's IRR. From the industry point of view, paying the full cost of reclamation in an up-front bond is the least attractive alternative. However, actual implementation of any financial assurance requires an industry-wide evaluation of financial assumptions.

Risks to the State

From the State's point of view, there is a risk that the well will become uneconomic prior to year 10, especially if production is much less than EQT Production's type curve. If this occurs, the shortfall of the 5-year severance tax would be greatest.

The problem of underperforming wells or dry holes, however, is not adequately addressed, and unless the "no risk" cash bond is employed, it is expected that both delayed funding options will result in inadequate funding of the reclamation trust account. In the coal industry, operators are required to make underfunded trust accounts whole either by direct payments into the trust or supplementary bonds. If regulations are strictly enforced to prevent dry holes and uneconomic wells from being granted inactive status, the risk of these wells becoming State liabilities decreases.

The risk of underfunded reclamation trusts due to dry holes or otherwise underperforming wells could be reduced if individual operators pooled monies in a reclamation trust. In this case, the severance tax would need to be based on the value of the pooled trust, aggregate production data, and total reclamation liability. To prevent operators from shirking environmental responsibility and ensure the State has adequate resources in case of insolvency, adjustments to the severance tax rate may be necessary so that pooled funds cover the sum of expected reclamation costs.

PADEP may readjust trust funding levels for the mining industry to reflect changes in pollution control costs of plus or minus 10%. However, regulatory inertia or poor oversight pose a threat to the achievement of adequate funding levels, as demonstrated by the lack of adjustment in oil and gas well bonding levels for more than a quarter-century. In theory, the potential for a downward adjustment of the required funding level incentivizes operators to invest in new technologies (or enhanced "pollution control") to lower the cost of reclamation and to have excess funds returned (*277*).

Disaggregating environmental accidents from well site restoration and closure

While bond forfeiture is commonly associated with operator failure to perform site restoration and plug abandoned wells, the intent of the current bonding system for oil and gas wells is much broader. At any time during the productive life of a well, noncompliance with the Oil and Gas Act or an order of the PADEP may be grounds for bond forfeiture. Restoration of water supplies impacted by nearby shale gas operations is an example.

The formation of a competitive bond market requires that liabilities be well defined in amount and time. Therefore, neither bonds nor trust accounts are the appropriate tool for environmental accidents that occur during production. A remedy could be for Pennsylvania to adopt financial assurance rules that separate expected liabilities from uncertain events such as casing failure or other environmental accidents. Requiring active operators to obtain liability insurance for uncertain events is a partial solution. Insurance companies would need to quantify potential risks and determine an efficient way to pool risk across multiple wells or operators. However, in the absence of a responsible operator, the State or affected citizen is likely to bear the cost in the event of an environmental issue post-reclamation.

Conclusions

The financial assurance mechanisms established by Act 13 that Pennsylvania uses to ensure compliance with Pennsylvania's Oil and Gas act of 1984 are inadequate and allow ownership transfers to entities less likely to be able to cover the expected costs of reclamation. Without strict enforcement of gas production reporting requirements, the PADEP will be unable to monitor compliance with plugging requirements and prevent abuse of the inactive status program. Timely plugging and abandonment should be the goal of PADEP policy because the long-term environmental and human health risks of shale gas development will increase over time and with the risk of operator insolvency. However, increasing the bonding requirements to fully cover reclamation costs, which is within the PADEP's mandate, will not address well-known limitations of environmental bonds and may limit participation in shale gas development to larger companies. Alternative mechanisms to ensure operators pay for future reclamation costs include a cash bond, a pre-drilling fee, and a severance tax. If operators were to deposit the full cost of reclamation in the form of a cash bond, the risk of underfunding approaches zero. Taxing gas production to fund an individual well trust account for future reclamation poses no additional barrier to operator entrance. This approach requires the State to assume the risk of reclaiming dry holes unless wells are pooled and a severance tax adjustable to funding levels in the trust, total reclamation liabilities, and production variability is developed. Generating funds directly from the revenue stream during the most lucrative years of gas production has the lowest impact on an operator's IRR. Though the industry generically predicts wells to operate for 40-50 years, reliance on these assumptions to define the terms of financial assurance increases the risk of underfunding and cannot be justified. Separate handling of reclamation and accidental environmental accident liabilities would promote the development of a competitive bond market if the current system is kept in place.

Abbreviations

BCF - billion cubic feet

Mcf - thousand cubic feet

TCM - thousand cubic meters

PADEP - Pennsylvania Department of Environmental Protection

IRR - internal rate of return

NPV - net present value

Chapter 5: Conclusion

The body of this thesis includes three analyses of health and environmental risks associated with the development of the Marcellus Shale. The radon study examined excess human lung cancer risk from exposure to radon in the natural gas delivered to Northeast U.S. homes and released to indoor environments by unvented gas combustion appliances. The surface water withdrawals study analyzed and compared the performance of regulatory frameworks designed to minimize the unconventional gas industry's impact to water resources. The well bonding study projected future costs of shale gas well plugging and site restoration, and assessed mechanisms for funding these liabilities.

Lung cancer risks

New population-level excess risk projections for domestic use of unvented gas burning appliances using locally-supplied natural gas were made. There are still many unknowns, but by accounting for a conservative range of plausible assumptions and calculating population-weighted exposure, it is unlikely that radon in natural gas poses a significant risk to public health at the population level. The scenarios most associated with elevated risk involved unvented gas appliance use in isolated and poorly ventilated spaces.

Water resources risks

The ability of the PADEP's water management plan requirements to protect streams from excessive water withdrawals for hydraulic fracturing was assessed with respect to meeting the stated goals of the program. The currently available streamflow data are sparse, and are often distant from desired surface water withdrawal locations. The combination of natural hydrologic variability and insufficient data can introduce significant uncertainties into the process to decide when and where water can be withdrawn with minimal impact to the stream. The current approach used by the PADEP in the Upper Ohio River Basin, based on annual streamflow statistics, is more robust to sparse data than alternative methods established using monthly streamflow statistics. Regulatory use of monthly streamflow statistics without 30 or more years of streamflow data to back them up risks allowing and disallowing withdrawals inappropriately. With as little as five years of streamflow data, the annual streamflow statistics are more likely to prevent water withdrawals when streams require the most protection. It makes sense to continue using this standard given the current state of the streamgaging network in the Upper Ohio River Basin.

Orphan well risks

The PADEP's financial incentives for well site reclamation and the actual costs to properly plug and abandon a Marcellus Shale well were compared. The current well bonds are *at least* a factor of 10 lower than they should be according to the requirements of Pennsylvania's Oil and Gas Act. In the coming decades, tens of thousands of new shale gas wells are expected to be drilled in Pennsylvania. From the perspective of the taxpayer, these wells represent tens of billions in unfunded future liabilities. Because the financial incentives are so misaligned, the PADEP's current financial assurance program will do little to prevent operators from defaulting on their liabilities, leaving them to the taxpayer. Higher bonds, or better yet, individual well trust accounts, are necessary to avoid a future orphan well problem.

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