Appendix B

Introduction

An emergence of new technologies, collectively known as unconventional gas well development (UGWD), has allowed industry to extract natural gas and oil from geological formations that were historically not economically viable. In some states these technologies, specifically hydraulic fracturing and horizontal drilling, facilitated an oil and gas boom before regulators were prepared with updated regulations or adequate staffing. At the same time concerns began to emerge on the health and environmental effects of chemicals, hazardous air pollutant emissions, noise, traffic, and other UGWD impacts. One of the nation's largest shale gas formations experiencing UGWD is the Marcellus Shale, which underlies portions of the westernmost counties in Maryland. The Maryland Departments of Environment and Natural Resources conducted a qualitative risk assessment of the UGWD process to determine whether Marcellus natural gas can be extracted safely. This risk assessment (RA) focuses on air emissions associated with UGWD.

This RA evaluates air emissions during major phases of the UGWD process. These phases include: site assessment, site preparation, drilling, hydraulic fracturing/completion, gas production/processing, and ancillary infrastructure (the reclamation phase was not considered as the site will be returned to pre-drilling conditions and no significant emissions are expected). Each phase of the UGWD process is described and the sources of air emissions identified. The duration and scope of the activity are also described and, where possible, estimated using two different development scenarios of 150 and 450 wells. These scenarios were developed by MDE and the Towson University Regional Economic Studies Institute (RESI) for use in RESI's study on the potential economic impacts of Marcellus gas, and estimate the number of wells and pads necessary to extract 25 percent and 75 percent of the available gas over a ten year period. A literature review of the air impacts associated with each activity is presented and then the current regulations/proposed best management practices (BMPs) to address those impacts are considered. A qualitative RA is then presented that considers the probability and consequence of impacts after consideration of applicable regulations and recommended BMPs.

Specific air emission risks the Departments were tasked to assess include: (1) combustion emissions from on and off-site vehicles, compressors and other equipment on the well pad; (2) noncombustion emissions such as volatile organic compounds (VOCs) and methane from wells during drilling and hydraulic fracturing/completion; (3) particulate emissions from traffic on unpaved roads; and, (4) accidents like well blowouts. Where other public health or environmental risks were identified during scientific literature review of UGWD, they were also included in the RA. This RA considers air emissions from some infrastructure beyond the well pad, such as gathering lines and compressors associated with gathering lines, but does not consider infrastructure further afield such as intrastate or interstate transmission pipelines, centralized processing or liquefaction plants, or distribution systems. The RA addresses potential exposures to human and environmental receptors beyond the well pad as these are within the purview of the Departments. The RA does not consider exposure to workers on the well pad as these are regulated by the federal Occupational Safety and Health Administration of the Maryland Department of Labor, Licensing and Regulation.

Regulatory Framework to Address Air Emissions

Air quality in the United States is regulated under the federal Clean Air Act (CAA). The CAA generally divides pollutants into two categories, criteria and non-criteria pollutants. For criteria pollutants (nitrogen oxides, sulfur oxides, carbon monoxide, particle pollution, lead and ground level ozone), EPA has established national ambient air quality standards (NAAQS) that establish levels of pollutants in the air that are protective of human health and welfare.

The CAA also has National Emissions Standards for Hazardous Air Pollutants (NESHAPs). EPA has not set ambient air concentrations for hazardous air pollutants (HAPs), often referred to as non-criteria pollutants. Instead, HAPs are regulated using a technology-based approach. Under this approach EPA identifies categories of sources for 187 hazardous air pollutants and requires those sources to implement the current best available technology. Every 8 years, EPA is required to determine if there are any residual risks for a particular source category and revise, as necessary, standards to address remaining risks. EPA promulgated new Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution in 2012 (78 FR 184).

The CAA divides emissions sources into stationary (e.g., factories, power plants) and mobile (e.g., cars, trucks, buses and non-road equipment) sources. Permits are issued for stationary sources or sources that remain in place for 12 or more months and where new or modified emissions exceed established amounts. Emissions standards for mobile sources are set by EPA, not states, and are regulated by requiring manufacturers to build cleaner cars, by reducing pollutant contents of fuels, and by requiring emissions inspection and maintenance programs in non-attainment areas. Currently, mobile sources account for half of the emissions of volatile organic compounds (VOCs), more than half of the emissions of nitrogen oxides, half of the HAPs emissions, and 75 percent of the carbon monoxide emissions nationwide (U.S. EPA, 2007).

For areas that are in attainment of NAAQS, the CAA requires that any new or modified stationary sources of air pollution not cause a significant deterioration of air quality. The CAA includes provisions to ensure that emissions from one state are not contributing to public health problems in downwind states. The CAA also allows states the ability to have stronger air pollution laws for stationary sources than provided for by the act. States with pollutant levels exceeding one or more of these standards are considered in nonattainment and are required to develop state implementation plans to achieve NAAQS.

Maryland has adopted all of the NAAQS in Title 26, Subtitle 11, Chapter 4, Section 2 of the Code of Maryland Regulations (COMAR 26.11.04.02). In addition, Maryland has defined a State Ambient Air Quality Standard for fluorides (COMAR 26.11.04.01). The State Ambient Air Quality Standard for fluorides, however, is not considered in this assessment because no emissions of fluorides are expected. Garret and Allegany Counties are currently in attainment of NAAQS, while the Baltimore region is in non-attainment of several standards. Upwind states are large contributors to air pollutants in Maryland that impact not only public health but also water quality in the Chesapeake Bay.

Maryland has other regulations that also help address air pollution. These include the following

- Regulations requiring listing all equipment available for the detection, prevention, and containment of gas leaks and oil spills (COMAR 26.19.01.06C(17)).
- Regulations establishing MDE's authority to not issue a drilling and operating permit if drilling or operations would result in physical and preventable loss of oil and gas (COMAR 26.19.01.09J).
- Sediments and erosion control regulations that help address dust generated during soil disturbance (MDE 2011)

Proposed Best Management Practices (BMPs)

In addition to the current regulations addressing stationary and mobile sources, the Departments are proposing additional best management practices, monitoring and setbacks to address air pollution sources. The current regulations and proposed BMPs are identified in Table 1,

Table 2, and Table 3, below, and are grouped according to the types of emission sources they are designed to address. These tables also categorize the BMPs according to effectiveness and the phase(s) of operations to which they apply.

The following general principles were used to evaluate BMP implementation effectiveness:

- BMPs that require implementation of defined best available control technologies (BAT) that have proven efficiencies at the start of operation are expected to mitigate risks to a greater degree than BMPs that require plans, time limitations to activities, reporting requirements, or general guidelines.

- BMPs that require implementation of a specific BAT should be distinguished from BMPs that provide flexibility for BAT implementation, as the latter is expected to result in site-specific efficiencies that may be difficult to verify and enforce.
- The availability, or lack-thereof, of literature or data confirming efficiencies of technology-based BMPs is considered when determining risk mitigation.

- BMPs that require documented plans are generally expected to identify measures that avoid or reduce impacts, though they may allow exceptions and require Departmental resources for plan review and compliance measures.

- BMPs that require reports or documentation, suggest limits to certain activities, and/or recommend certain measures are generally expected to have limited effectiveness because they are not prescriptive and can be difficult to verify or enforce.

Table 1: BMPs for Combustion Sources

Current Regulation or Proposed BMP	BMP Effectiveness	Phase(s) of Operations
Fuel Content: Ultra-Low Sulfur Diesel (ULSD) fuel (maximum sulfur content of 15 ppm)	BAT startup	All
Engine Combustions: Current clean air act regulations for mobile road and non-road engines	Depends on current fleet composition whether BAT start-up or in the future	All
Idling: Limit unnecessary idling to 5 minutes for both road and nonroad engines (exception for nonroad engines kept in ready reserve).	Guidelines/Behavioral	All
Power Plan: Require that applicants provide a power plan that results in the lowest practicable impact from the choice of energy source. This will include requirements that electricity be used from the grid or alternatively propane or natural gas, whenever possible	Reporting/ Documentation	All
Flares Must use: Raised/elevated flares or engineered combustion device with a 98 percent destruction efficiency of methane. No pit flaring is permitted. No flaring for more than 30-days on any exploratory or extension wells (for the life of the well) No visible emissions, except for periods not to exceed a total of five minutes during any two consecutive hours.	Combination of BAT startup and time limits.	Hydraulic fracturing/ completion

Table 2: BMPs for Non-combustion Sources

Current Regulation or Proposed BMP	BMP Effectiveness	Phase(s) of Operations
Venting: Green completion shall be achieved on all gas wells drilled in Maryland. In green completions, gas and hydrocarbon liquids are physically separated from other fluids and delivered directly into equipment that holds or transports the hydrocarbons for productive use. Reduced Emissions Completions shall also be required for re-fracturing.	BAT startup	Hydraulic fracturing/ completion
Storage Tanks: Except for tanks used in a closed loop system for managing drilling fluid and cuttings, which may be open to the atmosphere, tanks shall be closed and equipped with pollution control equipment specified in other sections of this report. Tanks must meet EPA's New Source Performance Standards.	BAT startup	Processing, Production
Compressors Certain compressors, namely single centrifugal compressor using wet seals that is located between the wellhead and the point of custody transfer to the natural gas transmission and storage segment (not at the well site), are required to reduce VOC emissions by 95% (40 CFR Part 60, Subpart OOOO).	BAT startup	Production
Leaks Leak Detection and Repair Program from wellhead to transmission line to include: Conforming to EPA's Natural Gas STAR program guidelines and EPA's best practice guidelines for leak detection and repair Listing all equipment available for the detection, prevention, and containment of gas leaks and oil spills (COMAR 26.19.01.06C(17)). MDE may not issue a drilling and operating permit if drilling or operations would result in physical and preventable loss of oil and gas (COMAR 26.19.01.09J). On site air pollution monitoring, discussed in the monitoring section, shall be included as an element of the leak detection program.	BAT startup	Production
Leaks All pipelines and fittings appurtenant thereto used in the drilling, operating or producing of oil and/or natural gas well(s) shall be designed for at least the greatest anticipated operating pressure or the maximum regulated relief pressure in accordance with the current recognized design practices of the industry.	Guidelines	Production
Dust from Vehicle Traffic Dust suppression guidelines from PA DCNR Guidelines for Administering Oil and Gas Activity on State Forest Lands (2011).	Guidelines/ behavioral	All

Dust from Soil Disturbance Maryland's sediments and erosion control regulations	Guidelines/ behavioral	Site preparation

Table 3: BMPs for Both Sources

Current Regulation or Proposed BMP	BMP Effectiveness	Phase(s) of Operations
Comprehensive Gas Development Plans	Planning BMP	All
Construction/Operations Plan: For each well, the applicant for a drilling permit shall prepare and submit to MDE, as part of the application, a plan for construction and operation that meets or exceeds the standards and/or individual planning requirements for Engineering, Design and Environmental Controls set forth in Section VI.	Planning BMP	All
Top-Down BAT: The Department of the Environment intends to require top-down Best Available Technology (BAT) for the control of air emissions. This means that the applicant will be required to consider all available technology and implement BAT control technologies unless it can demonstrate that those control technologies are not feasible, are cost-prohibitive or will not meaningfully reduce emissions from that component or piece of equipment. BAT emissions control technology will be mandatory for workovers1 . MDE will analyze top-down BAT demonstrations from applicants and approve the applicants BAT determination before a permit is issued. This includes all air pollution control elements in the EPA STAR program, and therefore the Departments are not proposing a separate requirement to participate in this voluntary EPA program.	BAT Startup	All
Well Blowouts Blowout prevention equipment shall be: (1) Installed before drilling the plug on the surface casing; (2) Tested to a pressure in excess of that which may be expected at the production casing point before: (a) Drilling the plug on the surface casing; and (b) Penetrating the target formation; and (3) Tested on a weekly basis according to standard operating practice (COMAR 16.19.01.10Q). Maryland is proposing a BMP that blow out preventers be installed and tested to ensure they can handle pressures at least 1.2 times the highest pressure normally experienced during the life of the blow out preventer or at least 1.2 times higher than the pressures experienced during well stimulation, whichever is greater.	BAT startup	Drilling, Hydraulic fracturing/ completion, processing, production

1 Workovers include the repair or stimulation of an existing production well for the purpose of restoring, prolonging or enhancing the production of hydrocarbons; it includes refracturing.

Expanded Monitoring If leak detection monitoring identifies releases of contaminants, additional air monitoring may be required. Applicants may be required to demonstrate compliance with state air toxics regulations. They would need to estimate emissions, use models, and show offsite concentration of air pollutants below health thresholds.	BAT startup	All
Setbacks Well must be set back 1,000 feet from the boundary of the property on which it is located, unless the Department grants a variance. Occupied buildings – 1,000-feet from a compressor, 1,000-feet from edge of disturbance. A setback of at least 2,000 feet from the edge of pad disturbance to any private well. (This BMP was not directed toward air emissions, but the setback will have the co-benefit of reducing the amount of air pollution that will reach a residence.) Aquatic habitat and special conservation areas - 450 and 650-feet, respectively, from edge of drill pad disturbance.	BAT Startup	All

Pertinent Chemical Characteristics of the Marcellus Shale in Maryland

Studies by the National Energy Technology Laboratory (NETL, 2011) and others (Repetski et al., 2005) indicate that the thermal maturity of the Marcellus play, represented by vitrinite reflectance values (R0%), increases eastward. R0% values greater than 1.6 are indicative of dry gas with few natural gas liquids (NGLs). Data from Maryland (Figure 1) indicate that R0% values are greater than 2 and indicative of dry gas. Dry gas consists of about 95 percent methane, 3 percent ethane, propane, and butane, and 2 percent non-hydrocarbon gases such as carbon dioxide, nitrogen, or helium (EPA, 2010). Wet gas can contain up to 20 percent of ethane, propane, and butane, and requires processing to remove NGLs before it can be distributed to consumers.

Since dry gas is expected to contain few natural gas liquids (NGLs), minimal processing will likely be necessary on well pads in Maryland. Processing of NGLs requires storage tanks on well pads that can result in potentially harmful emissions of volatile organics compounds such as benzene, toluene, ethylbenzene and xylene (BTEX). However, benzene and other volatiles can potentially be present in dry gas and released to the atmosphere wherever dry gas is emitted or incompletely combusted. Emissions of BTEX compounds are therefore assumed in this risk assessment.

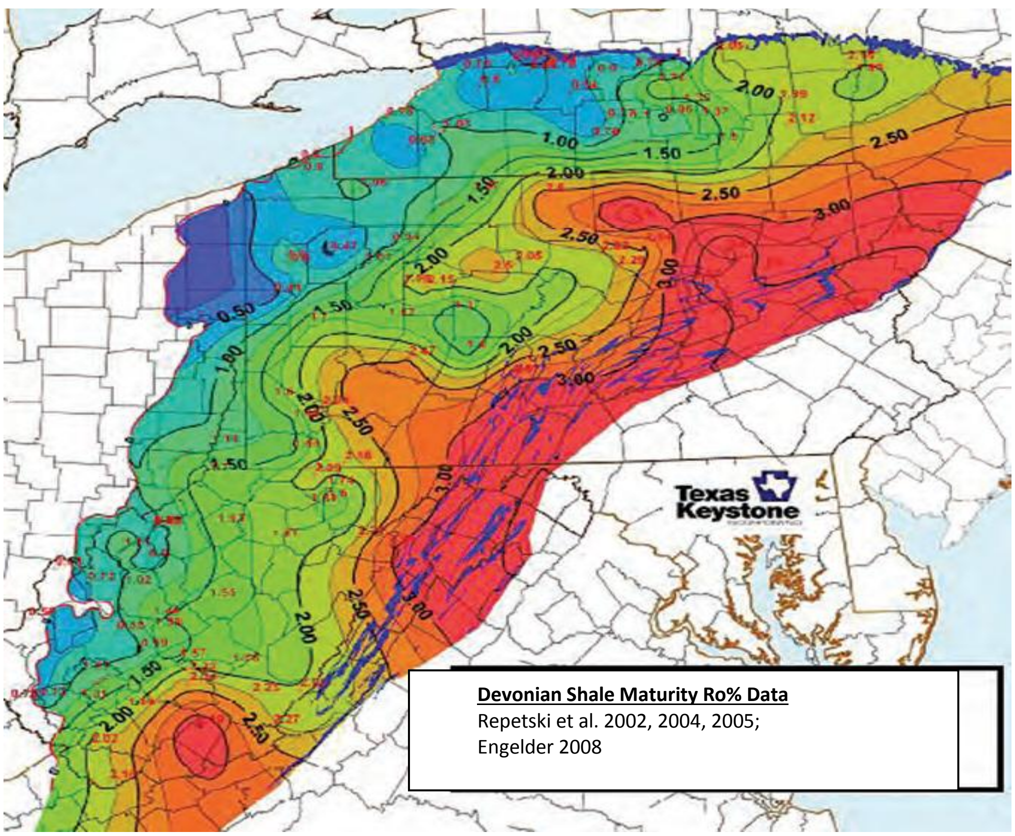

Figure 1: Vitrinite reflectance values (R0%) for Devonian Shale

Determining Risks During the Phases of Unconventional Gas Well Development (UGWD)

This section describes the major operational phases of the UGWD process, associated sources of air emissions, the duration and scope of activities specific to each phase, a current literature summary of the pollution potential and health risks associated with phase-specific emissions, and consideration of Maryland's current regulations and proposed BMPs followed by a qualitative risk assessment for each phase.

In assessing the risks associated with each UGWD phase, both the probability and consequences of air emissions are considered. Table 4and Table 5 below contain the definitions of terms used to classify emissions risks. The probability of air emissions is determined through evaluation of the scope and duration of activities in each phase. So for example, phases with year-round emissions have a higher probability than phases that are short-duration. The consequences of air emissions impacts during each phase are primarily determined from results of the literature reviews and how effective current and proposed BMPs are expected to be in terms of mitigating risks.

Table 4: Probability of Air Emissions

Low	Rarely happens under ordinary conditions; not forecast to be encountered under foreseeable future circumstances in view of current knowledge and existing controls on gas extraction
Moderate	Occurs occasionally or could potentially occur under foreseeable circumstances if management or regulatory controls fall below best practice standards
High	Occurs frequently under ordinary conditions
Insufficient Data to Determine	Lack of available data to confidently assign probability

Table 5: Consequence of Air Emissions

Minor	Slight adverse impact on people or the environment; causes no injury or illness
Moderate	Considerable adverse impact on people or the environment; could affect the health of persons in the immediate vicinity; localized or temporary environmental damage
Serious	Major adverse impact on people or the environment; could affect the health of persons in a large area; extensive or permanent environmental damage
Insufficient Data to Determine	Lack of available data to confidently assign consequence

Two scenarios are used to determine the scope and duration of air emissions during each UGWD phase. These scenarios assume 25 percent and 75 percent extraction levels of the available Marcellus resource in Maryland. These scenarios, in addition to equipment levels identified from literature sources, were used to determine the likely scope and duration of each phase. Table 6 and Table 7, below provide scenario details.

Table 6: Extraction Level Scenarios for the Marcellus Shale in Maryland.

Item	Scenario 1	Scenario 2
Extraction Level	25 percent	75 percent
Wells per pad	6	6
Average Wells Drilled/Year	15	45
Total Wells Drilled	150	450
Total Number of Well Pads	25	75

Table 7: Detailed Breakdown of Scenarios by Year.

Year	Number of New Wells Drilled	Number of New Well Pads	Total Number of Wells	Total Number of Well Pads
2017	8	4	8	4
2018	16	4	24	8
2019	29	3	53	11
2020	22	3	75	14
2021	18	3	93	17
2022	15	2	108	19
2023	12	2	120	21
2024	12	2	132	23
2025	12	2	144	25
2026	6	0	150	25
Yearly Avg.	15	2.5		

Year	Number of New Wells Drilled	Number of New Well Pads	Total Number of Wells	Total Number of Well Pads
2017	36	12	36	12
2018	72	12	108	24
2019	63	9	171	33
2020	54	9	225	42
2021	63	9	288	51
2022	42	6	330	57
2023	36	6	366	63
2024	36	6	402	69
2025	36	6	438	75
2026	12	0	450	75
Yearly Avg.	45	7.5		

In addition to the scenario assumptions, a few additional assumptions were made based upon information contained in New York's SGEIS and information gathered from draft permits for UGWD submitted to the Departments. These assumptions include the following:

- 15-acres of total site disturbance/land clearing per well pad, 4 of which are associated with the footprint of the well pad and road;

- 5,000,000-gallons of water used to hydraulically fracture each well and a 30 percent (1.5 million gallon) flow back rate. This information was used to estimate the number of truck trips necessary to deliver freshwater and transport flowback fluid. This is a conservative assumption as flowback water may be recycled for successive hydraulic fracturing events on a well pad.

Phase 1: Site Assessment

Activity/Description

Prior to conducting any drilling activities in a region, oil and gas companies routinely perform seismic assessment surveys to target the best locations for drilling exploratory/production wells. For the purposes of describing the nature of this activity and potential impact to air resources a permit application submitted to MDE by the PA General Energy Company (PAGEC) was reviewed. PAGEC established an approximately 3.9-mile transect along which the seismic survey would be conducted. A survey crew was deployed to lay out the transect line using traditional survey equipment. This was done on foot with minimal disturbance to the landscape. Survey flagging and pin flags were used to mark out the survey line.

The second phase entailed using a three-man crew and rubber-tired or track mount drill buggy (Figure 2). A four inch hole (referred to as a "shotpoint" hole) would be drilled to a 20-foot depth and then loaded with a 2.5-pound biodegradable charge. If a 20-foot hole could not be drilled, then three 10-foot holes would be drilled each containing a one-pound charge. These holes would then be filled with bentonite pellets with a hole plug used for the last 36-inches. In areas inaccessible by buggy, a cluster of seven 5-foot holes are dug with a 1/3 charge. These shotpoint holes are drilled every 110-feet for the first and last seven holes of the transect and 220-feet for the remainder of the shotpoints.

Figure 2: Drill Buggy (Photo courtesy of http://www.bertramdrilling.com/buggy.html)

The third phase involves collecting the seismic data. This entails a 15 to 20 man crew traversing the survey line on foot and potentially using an ATV to move equipment. The recording crew will lay out receivers and geophones along the survey route to record seismic data. Once the recording equipment is laid out the charges will be detonated individually and the recordings taken. When this has been completed, the crew removes recording equipment, flagging and pin flags.

Emission Sources

Combustion Sources

- Mobile Nonroad Sources: Drill buggy - Cat 3116 engine (200 HP) – see http://www.bertramdrilling.com/files/Terra%20Buggy.pdf
- Mobile Road Sources: Trucks used to deliver equipment to seismic assessment site.

Non-Combustion Sources
N/A

Accidents
N/A

Activity Duration and Scope

Duration:

Up to 120 days, based upon maximum length of time indicated from a draft permit application in Maryland.

Scope:

Do not anticipate that seismic survey activity will increase appreciably from the 150 well to the 450 well scenario as a single survey application from PA General Energy Company covered an approximately 3.9-mile transect.

Literature Review of Air Impacts

No literature sources quantifying air emissions from seismic survey assessments were found. This is most likely due to the narrow scope of activity and few emissions sources with low overall loads.

Risk Assessment

Any air impacts associated with seismic assessment operations result from internal combustion engine emissions and are presented in Table 8. These emissions are generated from mobile road sources used to deliver equipment to the site and non-road sources used to perform the drilling/seismic thumping procedures and traverse the transect line. However, few pieces of equipment are used to assess a wide geographic area resulting in negligible air emissions. In addition, existing Clean Air Act regulations for mobile road and non-road sources require standardized control technologies to address these sources and no literature could be found indicating any air impacts from the seismic assessment phase. As a result these facts, the probability of occurrence is considered low and the potential consequences minor.

Table 8: Risk Assessment for Phase 1 – Seismic Assessment

Scenario	Duration	Scope	Emissions Type	Pollutants of Concern	Impact	Probabilit y	Conseq uence	Risk Ranking
Same for both Scenarios	120 days	1 drill buggy or “thumper” truck and associated trucks necessary to bring these on site.	Combustion from engines	NOx, PM	Human (Inhalati on)	Low	Minor	Low

Phase 2: Site Preparation

Activity/Description

Site preparation involves clearing, leveling, and excavation (Figure 3) at a well site to install the well pad, freshwater pits, and any associated access roads. The Department reviewed language from one of Maryland's draft permit applications for gas well development that describes these activities as follows:

Estimate earthwork will be done in 2 contractor mobilizations – the first mobilization is for constructing the fresh water pit, well pad and access roads; the second mobilization will happen when the site is reclaimed after well drilling. First filter fabric is installed around site perimeter, then clear and grub areas required for access roads and well pad. Strip topsoil and place in stock piles. Proceed to grading and compacting using rollers/sheepsfoot. After final grading is complete and the site has been mulched/seeded, perimeter controls can be removed with County approval. Also, place down geotextiles and crushed stone for the well pad and roads.

Figure 3: Excavation/Earth Moving Equipment (Photo courtesy of www.co.monterey.ca.us/.../gr ade/grading_powerpoint_060805.pps)

Emission Sources

Combustion Sources
Mobile Nonroad Sources: general construction equipment (bull dozers, graders, loaders, dump trucks, and clearing equipment) powered by diesel engines.
Mobile Road Sources: Trucks used to deliver equipment to the site.

Non-Combustion Sources
Fugitive dust/particulate emissions from earth moving and road traffic.

Accidents
N/A

Activity Duration and Scope

Duration:

Up to 4 weeks per multi-well pad (NYSDEC, 2011)

Scenario 1: Average of 15 new wells/year. Using six wells per pad results in an average of 2.5 multi-well pads/year = 10 weeks/yr. of site prep. A maximum of 4 pads in a year results in 16 weeks/yr of activity.

Scenario 2: Average of 45 new wells/year. Using six wells per pad results in an average of 7.5 multi-well pads/year = 30 weeks/yr. of site prep. A maximum of 12 pads in a year results in 48 weeks/yr of activity.

Scope:

Pads may be widely spaced. A common assumption is no more than one well pad per square mile. We assumed a total average disturbance of 15-acres per multi-well pad and following the assumption of 45 heavy trucks and 90 light trucks (Table 9) for drill pad construction based upon modified information from New York (NYSDEC, 2011), which can be seen in below:

Table 9: Estimated truck trips during Phase 2 Site Preparation.

Well pad activity	Equipment	
	Heavy trucks	Light trucks
Drill pad construction	45	90

Scenario 1: An average of 2.5 pads/year to a max. of 4 pads/year results in anywhere from approximately 113 to 180 heavy truck trips/year and 225 to 360 light truck trips/year. Total area disturbed/year is 38-acres on average with a maximum of 60-acres in any given year. There will likely be simultaneous emissions from site preparation at different pads.

Scenario 2: An average of 7.5 pads/year to a max. of 12 pads/year results in 338 to 540 heavy truck trips/year and 675 to 1080 light truck trips/year over ten years. Total area disturbed/year is 113-acres on average with a maximum of 225-acres in a year. There will likely be simultaneous emissions from site preparation at different pads.

Literature Review of Air Impacts

There was scant literature found on site preparation activities associated with well pad development for oil and gas production specifically, but site clearing and grading impacts for the construction industry are well documented. Potential air impacts associated with construction site preparation include: (1) mobile source combustion emissions that contain particulate matter, nitrogen oxides and hazardous air pollutants; (2) particulate emissions resulting from soil disturbance and suspension; and, (3) greenhouse gas emissions (carbon dioxide and nitrous oxide emissions (Sacramento Air Quality District, 2009)

Risks Assessment

Air impacts during this phase are associated with combustion emissions from equipment delivery as well as during site clearing, grading, excavation, road and well pad construction. Diesel exhaust (DE) is one of the largest U.S. sources of fine particulate matter and also contains ozone-forming nitrogen oxides and toxic air pollutants (”Diesel Engine Exhaust”). DE has been classified by EPA as having chronic non-cancer (exacerbates asthma and other respiratory conditions, neurological effects, growth and survival) and carcinogenic (lung cancer, mutagenic/chromosomal) effects from inhalation (U.S. EPA, 2003b). Dust/particulate emissions are also generated when disturbing soil and handling aggregates used in well pad or road construction. However, little information is available regarding overall exposures and environmental or human health effects of combustion or dust emissions specifically from well pad site preparation.

To better understand the magnitude of development from well pad site preparation activities, it is helpful to look at overall development statistics for Allegany and Garrett Counties. The Maryland Department of Planning (2010) publishes land use data, in acres for 1973, 2002 and 2010. The categories are developed land (residential, commercial, industrial, institutional, transportation, other) and non-residential) and resource land (agricultural, forest, extractive/barren/bare, wetland).

Table 10: Land Use in Allegany and Garrett Counties

Category	1973	2002	2010
Total developed lands (Allegany)	21059	32468	35853
Total resource land (Allegany)	245630	234316	230930
Total land (Allegany)	266689	266784	266783
Total water (Allegany)	2820	2725	2725
Total developed lands (Garrett)	13368	37689	41797
Total resource land (Garrett)	406425	381603	377496
Total land (Garrett)	419293	419293	419293
Total water (Garrett)	5635	5767	5767

These data indicate that the percentage of total land developed in Allegany County increased from 1973 to 2010 from 7.9 percent to 13.4 percent and approximately 14,794 acres were developed during that time. Under scenario 2, the build out predicted for Allegany County is 10 well pads; if each well develops 15 acres, 150 acres would be developed, or 0.06 percent of all the land in the County.

Garrett County is larger and less developed than Allegany County. Garrett County is predicted to support 65 well pads under scenario 2. The percentage of total land developed in Garrett County increased from 1973 to 2010 from 3.2 percent to 10 percent and approximately 28,429 acres were developed during that time. If 65 well pads are constructed, 975 acres would be developed, representing 0.23 percent of land in the County.

The probability of combustion emissions (Table 11) are considered high since they will occur routinely from site preparation activities. However, the relatively limited scope and duration of site preparation activities coupled with current technology-based Clean Air Act regulations for mobile vehicle sources reduces overall human health and environmental consequences to minor levels. Maryland also has standards and specifications for sediment and erosion control (MDE 2011) to help address dust control measures during site preparation. Proposed setbacks from property lines and occupied residences also help reduce direct human exposure to particulate matter and hazardous air pollutants associated with diesel exhaust emissions.

Table 11: Risk Assessment for Phase 2 – Site Preparation.

Scenario	Duration	Scope	Emissions Type	Pollutants of Concern	Impact On	Probability	Consequence	Risk Ranking
Scenario 1	10-16 Weeks	225-360 Trucks	Combustion from engines	NOx, benzene, PM	Human (Inhalation)	High	Minor	Moderate
			Fugitive dust from earth moving and truck traffic on unpaved roads.	PM				
Scenario 2	30-48 Weeks	675 – 1080 Trucks	Combustion from engines	NOx, benzene, PM	Human (Inhalation)	High	Minor	Moderate
			Fugitive dust from earth moving and truck traffic on unpaved roads.	PM				

Phase 3: Drilling

Activity/Description

After the site has been prepared and the drilling pad installed, one or more drill rigs (Figure 4) are brought on-site to conduct well drilling. Drilling entails creating a vertical bore hole approximately 2-3km deep, and then drilling horizontally up to 4km. In order to lubricate the drill bit and bring drill cuttings to the surface, fluid mud or air is used. In NY, most vertical drilling is done using air while the horizontal drilling typically uses mud (NYSDEC, 2011, p.5-32) . Drill cuttings come to the surface along with the drilling muds and are pumped into a machine that separates the cuttings from the mud so that the mud can be reused. Methane encountered when drilling can infiltrate drilling muds and be brought to the surface. A mud gas separator is used to separate introduced gas from drilling muds which can result in emissions of methane and associated compounds. When air drilling occurs, there is also a potential for particulate matter emissions from pulverized rock being blown out of the well bore.

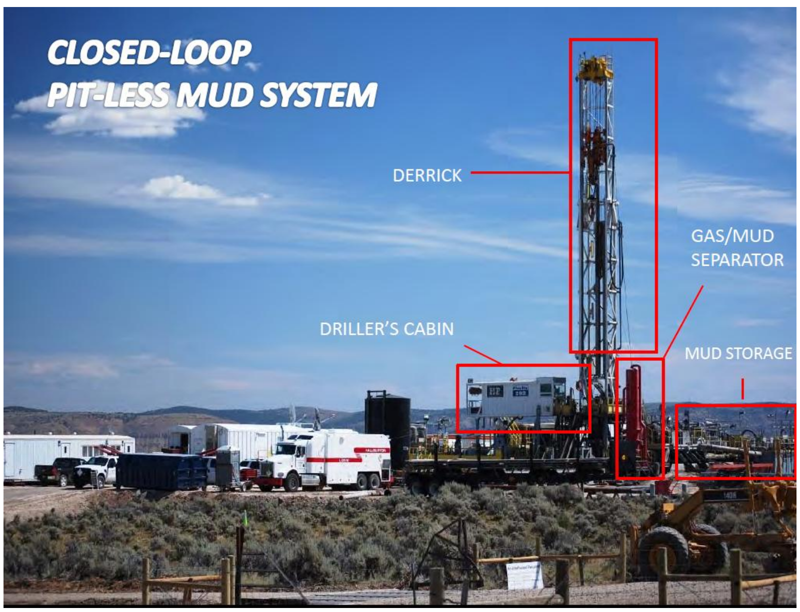

Figure 4: Drill Rig (Photo courtesy of the Colorado Oil and Gas Conservation Commission).

Drill rigs are also used to case the well bore. Typically, three levels of casing (surface, intermediate, and production) are used in a telescoping fashion: (1) the surface casing is run from the land surface to below the deepest freshwater layer; (2) the intermediate casing is run from the surface casing down to the target formation; and, (3) the production casing is run from the intermediate casing through the target formation. All casing strings are cemented in place to stabilize the well string and also seal the annular space between the casing and borehole to prevent gas or fluid migration between geologic strata. A blow-out prevention system is often installed on top of the surface casing in order to control well pressure during drilling in case of a sudden gas release, called a gas "kick' ("Natural Gas-From Wellhead to Burner Tip").

After the casing and cement are in place, the drilling rig is replaced by a temporary wellhead and the well is prepared for perforation by flushing with acid to remove cement and other debris. Freshwater is often delivered to the site during the drilling phase and for the hydraulic fracturing phase that follows via tank trucks. Tanks that store flowback from hydraulic fracturing may also be delivered during the drilling phase.

Figure 5: Typical Tank for Hauling Water (Photo courtesy of http://www.jjbodies.com)

Emission Sources

Combustion Sources
Drill Rig Engine/Compressor – New York (NYSDEC, 2011) cites a 5,400 hp diesel drill rig with year-round emissions.
Emissions from trucks used to deliver drilling fluids, chemicals, fracking water, and cement and to move equipment on site.

Non-Combustion Sources
Methane and associated chemical release directly to air during drilling (gas "kick") and/or from mud/gas separator
Dust/particulates re-suspended from air drilling and truck traffic on unpaved roads during freshwater and tank/equipment delivery.

Accidents/Spills
Blow-out during well drilling

Activity Duration and Scope

Duration:

Up to 5 weeks (NYSDEC, 2011, p. 5-27) per well.
Scenario 1: Assuming 6 wells drilled simultaneously on an average of 2.5 pads results in 30 weeks (6 wells X 5 weeks/well) of drilling.
Scenario 2: Assuming 6 wells drilled simultaneously on an average of 7.5 pads results in 30 weeks (6 wells X 5 weeks/well) of drilling.

Scope

One small and one large drill rig are assumed to be used to drill each well. There also may be one mud gas separator per well pad. The truck trips per well, modified from NY (NYSDEC, 2011), are estimated below at 1889 truck trips (Table , 1283 heavy trucks, 606 light trucks) per well. To scale up to the estimated 6 wells per pad results in a total of 10,194 trips (
Table , 7,118 heavy trucks, 3,076 light trucks) per 6-well pad.

Table 12: Truck trips for drilling one well on a pad.

Well pad activity	Early well pad scenario (All water transport by truck)	
	Heavy trucks	Light trucks
Rig mobilization	95	140
Drilling fluids	45	
Non-rig drilling equipment	45	
Drilling (rig crew, etc.)	50	140
Completion chemicals	20	326
Completion equipment	5	
Hydraulic fracturing water hauling	1000*	
Hydraulic fracturing sand	23	
TOTAL truck trips During Drilling (1 well on 1 pad)	1283	606

Table 13: Truck trips for drilling 6 wells on a pad.

Well pad activity	Early well pad scenario (All water transport by truck)	
	Heavy trucks	Light trucks
Rig mobilization	190	280
Drilling fluids	270	
Non-rig drilling equipment	90	
Drilling (rig crew, etc.)	300	840
Completion chemicals	120	1956
Completion equipment	10	
Hydraulic fracturing water hauling	6000*	
Hydraulic fracturing sand	138	
TOTAL truck trips per well pad (6 wells)	7118	3076

Sources: NYSDEC 2011, NTC Consultants 2011, All Consulting, 2010.
*Modified from All Consultants 2010 to account for 5,000,000 gallons/well and 5,000 gallons/truck.

Scenario 1: 15 wells/year with likely simultaneous emissions from well drilling on different pads at the same time. Assuming wells are on multi-well pads results in total truck trips of approximately 25,485 (10,194 trips X 2.5 well pads) per year. Also, assume total emissions from 15 drill rigs (one per well). Assume 3 mud/gas separators at 1 for each well pad at 2.5 pads.

Scenario 2: 45 wells/year with likely simultaneous emissions from well drilling at different pads at the same time. Assuming wells are on multi-well pads results in total truck trips of approximately 76,455 (10,194 trips X 7.5 well pads) per year. Also, assume total emissions from 45 drill rigs (one per well). Assume 8 mud/gas separators at 1 for each well pad at 7.5 pads.

Literature Review of Emissions from Combustion Sources

The State of New York Supplemental Generic Environmental Impact Statement (NYSDEC, 2011) is the only study found where modeling of combustion emissions during drilling was performed. One very important limitation to this modeling analysis was that it did not include simultaneous emissions impacts from trucks used to transport fracking water, tanks and other equipment to the well pad. Therefore, the only modeled source in NY's analysis was emissions from the drilling rig itself and an onsite compressor. Conservative assumptions (i.e., year-round continuous operation at a well pad) were built into New York's modeling and interested parties can refer to that documentation for additional details. The results of NY's modeling for combustion sources of criteria pollutants are presented below. Noncriteria pollutant emissions found by other studies during drilling are also discussed.

Criteria Pollutants

Particulate Matter
The Tier 1 drilling rig engine/compressor modeled by NY exceeded 24-hour PM2.5 standards up to 120-meters away. (NYSDEC, 2011, p. 6-143)

NO2
The Tier I drilling rig engines modeled by NY exceeded the NO2 1-hour standard by a factor of 2 up to 150-meters away unless equipped with particulate traps and selective catalytic reduction technology to meet standards. (NYS DEC, 2011, p. 6-150)

SO2
No impacts expected due to use of ultra low sulfur fuel.

Non-criteria Pollutants

Non-criteria pollutant emissions considered during the drilling phase result from any fugitive natural gas that escapes through the borehole during drilling (i.e., gas "kick" or seepage from the formation), that is entrained and released from the drilling muds used to drill the well, or as a result of a catastrophic event such as a well blow-out. These emissions will vary depending upon the specific geology at a drill site and the associated quantities of gas and related chemicals at a particular well. This variability makes emission impacts difficult to model and assess. However, a recent study (Caulton et al., 2014) found large emissions averaging 34 grams of methane per kilometer per second during the drilling phase of operations. These recent estimates are 2-3 orders of magnitude higher than EPA estimates for this phase of operations. This study surveyed drilling emissions in areas predominately underlain by coal beds and more study is needed to determine whether calculated emissions rates are typical of gas well drilling generally. Another recent study (Colburn et al., 2012) in Colorado found non-methane hydrocarbons (NMHCs) emissions to be highest during this initial drilling phase. Since Maryland's portion of the Marcellus is expected to be comprised of dry gas with little natural gas liquids, NMHC emissions measured in the Colorado study may not be representative of potential drilling emissions in Maryland.

Table 14 below identifies the frequency of well blowouts documented by the International Association of Oil and Gas Producers for off-shore wells. Offshore well data were used because these were more robust data compared to data from relatively new onshore unconventional gas wells. This table identifies the number of blowout incidents for exploration and development drilling in shallow and deep natural gas reservoirs as follows: blowouts during exploration drilling in shallow gas reservoirs (22 per 13,762 = .0016 or 1.6 incidents per 1,000 wells); blowouts during development drilling in shallow gas reservoirs (23 per 22,833 = .001 or 1 incident per 1,000 wells); blowouts during exploration drilling in deep gas reservoirs (29 per 13,762 = .0021 or 2.1 incidents per 1,000 wells); blowouts during development drilling in deep gas reservoirs (11 per 22,833 =

.0005 or .5 incidents per 1,000 wells). Taking the average of these incidence rates results in 1.2 blowouts per 1,000 wells drilled.

Table 14: Offshore gas well blowout rates for different phases of operations.

Operation	Category	Well Type	No. of Wells/Incidents
Exploration Drilling, shallow gas	Number of Exploration Wells Drilled	Appraisal	6,257 Wells
		Wildcat	7,505 Wells
	Blowout (surface flow)	Appraisal	8
		Wildcat	14
	Blowout (underground flow)	Appraisal	0
		Wildcat	0
	Diverted well release	Appraisal	2
		Wildcat	7
	Well release	Appraisal	2
		Wildcat	2
Development Drilling, shallow gas	Number of Development Wells Drilled	-	22,833 Wells
	Blowout (surface flow)	-	22
	Blowout (underground flow)	-	1
	Diverted well release	-	16
	Well release	-	2
Exploration Drilling, deep	Number of Exploration Wells Drilled	Appraisal	6,257 Wells
		Wildcat	7,505 Wells
	Blowout (surface flow)	Appraisal	9
		Wildcat	13
	Blowout (underground flow)	Appraisal	0
		Wildcat	7
	Diverted well release	Appraisal	01
		Wildcat	01
	Well release	Appraisal	3
		Wildcat	3
Development Drilling, deep	Number of Development Wells Drilled		22,833 Wells
	Blowout (surface flow)	-	8
	Blowout (underground flow)	-	3
	Diverted well release	-	0
	Well release	-	5
Completion	Number of Completions		20,328 Wells
	Blowout (surface flow)	-	9
	Blowout (underground flow)	-	0
	Diverted well release	-	6
	Well release	-	0
Production	Number of Well Years in Service		211,142 Well Years
	Blowout (surface flow)	-	7
	Blowout (underground flow)	-	1
	Diverted well release	-	0
	Well release	-	2

Workover	Number of Workovers		19,920 Workovers
	Blowout (surface flow)	-	20
	Blowout (underground flow)	-	0
	Diverted well release	-	0
	Well release	-	17

Risk Assessment

Risks from Combustion Sources

Diesel exhaust (DE) is one of the largest U.S. sources of fine particulate matter and also contains ozone-forming nitrogen oxides and toxic air pollutants (”Diesel Engine Exhaust”). DE has been classified by EPA as having chronic non-cancer (exacerbates asthma and other respiratory conditions, neurological effects, growth and survival) and carcinogenic (lung cancer, mutagenic/chromosomal) effects from inhalation (U.S. EPA 2003). However, little information is available regarding overall exposures and environmental or human health effects of combustion emissions specifically during UGWD drilling-related activities.

Modeling studies conducted by the state of New York on the drilling equipment show exceedances of the 1-hour NOx and PM2.5 standards at 120 and 150-meters away from the well pad, respectively (NYSDEC, 2011). Using Tier II or greater DE engines would help address PM exceedances (NYSDEC, 2011, p. 6-144), while use of particulate traps and selective catalytic reduction technology would help address NOx emissions. Neither of these practices has been specifically recommended in Maryland and it is currently unclear whether the federal Clean Air Act preempts Maryland from doing so. The setback requirements proposed in Maryland are, at minimum, 2-times greater than the distance at which exceedances were modeled in New York and are expected to be effective mitigation for drilling rig emissions.

Uncertainty for potential health risks in terms of combustion emissions results from the high volume of vehicle traffic necessary to transport fresh water and other equipment to the site during the drilling phase and prior to hydraulic fracturing. Maryland’s calculation of vehicle traffic, modified from NY’s analysis, estimated 1889 truck trips (1283 heavy trucks, 606 light trucks) per single well and 10,194 (7,118 heavy trucks, 3,076 light trucks) per 6-well pad. Scaling this up to the 150 and 450 well scenarios results in anywhere from approximately 25,000 to 76,000 truck trips per year. Diesel trucks are regulated under Title I of the Clean Air Act, which is a technology-based program that is expected to control emissions over a longer period of time as new equipment is phased in. As a result, older, higher emissions vehicles may still be in industry fleets. Minimizing diesel idling to less than 5 minutes can help reduce emissions, but this is not practicably enforceable and may be counter to the behavior of many operators who are in the habit of leaving engines idle to prevent difficulty with engine restarting, particularly in cold weather. Maryland’s proposed setback distances are calculated from the well pad and may not effectively mitigate human exposure to air emissions from off-site vehicles.

Overall due to both drill rigs and the high number of trucks used to deliver supplies/equipment, there is a high probability of combustion emissions in both scenarios. Modeling results presented by NY show Tier 1 drill rig combustions exceeding criteria pollutant concentrations up to 150-meters away and no exceedances if drill rigs are Tier II. With Maryland proposing 1,000-foot well pad setbacks from property boundaries and from occupied dwellings, at least a 2,000 -foot setbacks from private wells, current CAA regulations, and considering the relatively short duration of the drilling phase, the consequences of these drill rig emissions are expected to be minor. CAA regulations for mobile sources are implemented as new equipment/vehicles are purchased and as vehicle fleets modernize. However, because no existing fleet inventory is available to quantify emissions associated with mobile sources and no modeling has been completed for Maryland’s scenarios, there is currently insufficient information (i.e., fleet composition and associated emissions controls) regarding combustion emissions from truck traffic to assess consequences (Table 15).

Risks from Non-Combustion Sources

The air risks from non-combustion sources include methane and associated hydrocarbon release during drilling and mud/gas separation, dust generated from vehicle traffic on unpaved roads, as well as the rarer instances of well blow-outs. Increased risks for global warming resulting from methane release during drilling activities is a larger national energy policy issue and is discussed separately in the greenhouse gases section. Overall, however, the probability of noncombustion emissions during drilling are considered moderate as they would be likely to occur with air drilling when no drilling fluid is available to help contain fugitive gas as well as with drilling muds where gas may be entrained and released directly to the atmosphere from mud pits. With setbacks and the likelihood of dry gas with little associated natural gas liquids, the probability of VOC emissions or other compounds associated with methane are anticipated to pose only minor health risks during the drilling phase.

The greatest probability of non-combustion air emissions are anticipated as a result of dust/particulate matter generated from heavy vehicle traffic on unpaved roads. As shown above, annual truck trips are estimated to be anywhere from 25,000 to 76,000. Since access roads are likely to be unpaved, this high volume of truck traffic will generate fugitive dust and particulates. Vehicle traffic-generated dust is noted in some studies as an impact (Adgate et al., 2014), but no studies were found that measured or otherwise quantified increases in dust levels. Dust control BMPs proposed by Maryland are considered guidelines, are discretionary/not prescriptive, and consequently difficult to enforce. As mentioned above, setbacks were not created to address emissions from vehicle traffic away from access roads. Proposed particulate air monitoring may help determine when traffic-generated dust requires additional control.

Risk from Accidents

As indicated above in Table 14, well blowouts during drilling are relatively rare (approximately 1 in 1,000) and typically pose the greatest risk to workers on site. Maryland's requirement for blow-out preventers that are designed to withstand up to 1.2 times the maximum expected well pressure will help prevent well blow-outs from occurring. In addition, the proposed 1,000-foot setbacks from occupied buildings, and the setback of at least 2,000 feet from private wells will further reduce risks to off-site citizens. No instances were found in current literature of off-site citizens being killed or injured from well blowouts. The greatest risk of well blow-outs is to onsite workers and worker safety is not regulated by the Departments. As a result, risks to on-site workers are considered outside the scope of this assessment and were not evaluated. Overall the probability of well blow-outs is considered low due to both a low frequency of occurrence and application of Maryland's proposed BMPs. Since proposed setbacks are expected to be very effective in protecting off-site citizens from blow-outs, consequences are rated as minor.

Table 15: Risk Assessment for Phase 3 – Drilling.

*Global warming risk of methane not assessed (see Greenhouse Gases section)

Scenario	Duration	Estimated Number of Emissions Sources/Loads	Emissions Type	Pollutants of Concern	Impact On	Probability	Consequence	Risk Ranking
Scenarios 1 and 2	30 weeks	15-45 large and small drill rig with compressors	Combustion	NOx, benzene, PM	Human (Inhalation)	High	Minor	Moderate
			Non-combustion	VOCs/Natural Gas Liquids, methane*	Human (Inhalation)	Moderate	Minor	Low
		1 well blowout per 1,000 wells	Accidents/Spills	N/A	Human (Explosion)	Low	Minor	Low
		3-8 Separators and tanks to hold drilling muds.	Non-combustion	VOCs/Natural Gas Liquids, methane*	Human (Inhalation)	Moderate	Minor	Low
		25,000 – 76,000 truck trips per year.	Combustion	NOx, PM, benzene	Human (Inhalation, Ozone formation)	High	Insufficient data	Insufficient data
			Noncombustion	Dust/PM	Human (Inhalation)	High	Insufficient Data	Insufficient data

Phase 4: Hydraulic Fracturing/Completion

Activity/Description

During hydraulic fracturing, the horizontal section of the well is perforated by a series of explosive charges that create small fractures in the target formation in preparation for hydraulic fracturing. Then millions of gallons of water, added chemicals and sand proppant are pumped down the well at high pressure to further fracture the shale. As the fracking water penetrates and enlarges the initial fractures created by the explosive charges, the included proppant (usually silica) fills the interstitial spaces of the created fractures and keeps them propped open so that produced gas can flow into the well. Approximately 14-15 diesel-powered hydraulic fracture pumps (are used on site to pressurize the hydraulic fracking fluid (NYSDEC, 2011).

Figure 6: Hydraulic Fracturing Pumps (Photo courtesy of http://www.jjbodies.com)

Once fracturing is complete, some of the injected fracturing fluids return to the surface as flowback. During the flowback period both hydraulic fracturing fluids and other naturally occurring materials contained in the formation (salts, metals, potentially naturally occurring radioactive materials, natural gas liquids) migrate back to the surface as a result of overlying geological pressure. The flowback is routed to storage tanks on site which have vents that can emit volatile organic compounds to the atmosphere (
Figure 7). The portion of Maryland underlain by the Marcellus Shale (Figure 1) is expected to consist mostly of dry gas with few hydrocarbon liquids. However, hydrocarbon liquids may be present and can consist of commercially valuable liquids (ethane, propane, butane, and pentanes), inert gases (water vapor, helium, and nitrogen), greenhouse gases (carbon dioxide), and compounds with known human health effects (hydrogen sulfide formaldehyde, and benzene, toluene, ethylbenzene and toluene –BTEX) (McKenzie et al., 2012; “Oil and Natural Gas Air Pollution standards”; “Natural Gas-From Wellhead to Burner Tip”).

Figure 7: Flowback Tanks (Photo courtesy of the Colorado Oil and Gas Conservation Commission)

Natural gas also begins to flow to the surface with the flowback liquids. Natural gas produced at this stage may be temporarily vented to the atmosphere and then ignited by a flare (for testing purposes to determine well pressure, flow and composition (Ohio EPA, 2012). These processes result in combustion and noncombustion air pollution emissions. In some cases if natural gas flow is insufficient, refracturing can occur soon after the initial fracturing to stimulate well production (NYSDEC, 2011, p. 5-98). Refracturing can also occur years later when natural gas production falls below desirable levels.

Emission Sources

Combustion Sources
Pumps for injecting hydraulic fracturing fluid – 15 fracturing pump engines total assumed in NY at 2,333 hp each. (NYSDEC, 2011, p. 6-101)
Flares (McKenzie et al., 2012)
On and off-road vehicle activity. (NY DEC, 2011 , p. 6-115; Leidos, 2014a)

Figure 8: Flares (Photo courtesy of Ohio EPA)

Non-Combustion Sources
Venting/emissions from flowback and storage tanks (Alvarez &Paranhos, 2012)
Silica emissions when proppant is mixed with fracking water and chemicals. (Adgate, 2014)

Accidents
Well blowouts

Activity Duration and Scope

Duration

Hydraulic Fracturing
5 days per well for the actual fracking - 2 days to mobilize and demobilize fracking equipment. (ALL Consulting, 2010)
Scenario 1: At 150 wells, an average of 15 wells/year = 75 days/yr of fracking
Scenario 2: At 450 wells, an average of 45 wells/year = 225 days/yr of fracking

Flowback: 3-10 days (Avg. 6.5 days, U.S. EPA, 2012)
Scenario 1: At 150 wells, an average of 15 wells/year = 98 days/yr of flowback
Scenario 2: At 450 wells, an average of 45 wells/year = 293 days/yr of flowback

Venting/Flaring – 1 day to several weeks (U.S. EPA, 2011) and completely or partially overlaps with the flowback phase.

Scope

Flowback volume is estimated at 30 percent of the average volume of hydraulic fracturing fluid injected into the well, or 1.5 million gallons of fluid that may contain volatile organic compounds and other contaminants. The truck trips per well to transport equipment and remove flowback discharge, modified from New York (NYSDEC, 2011), are estimated below at 655 truck trips (520 heavy trucks, 135 light trucks) per single well. To scale up to the estimated 6 wells per pad results in a total of 2,645 trips (2,195 heavy trucks, 450 light trucks) per 6-well pad, although this is likely a high estimate as flowback water may be recycled. In addition to the truck trips, there are approximately 15 hydraulic fracturing pumps used for each well. A typical flowback tank holds 21,000-gallons ("Frac Tanks") of flowback resulting in approximately 72 tanks per pad (1.5 million gallons divided by 21,000 gallons/tank). Table 16: and Table 17 below display well pad activity with both scenarios:

Table 16: Well Pad Activity with 1 Well on 1 Pad

Well pad activity	**Early well pad scenario (All water transport by truck)**	
	Heavy trucks	Light trucks
Hydraulic fracturing equipment (trucks & tanks)	175	
Produced water disposal	300**	
Final pad prep	45	50
Miscellaneous	0	85
TOTAL truck trips per well (1 well on 1 pad)	520	135

Table 17: Well Pad Activity with 6 Wells on 1 Pad

Well pad activity	**Early well pad scenario (All water transport by truck)**	
	Heavy trucks	Light trucks
Hydraulic fracturing equipment (trucks & tanks)	350	
Produced water disposal	1800**	

Final pad prep	45	50
Miscellaneous	0	400
TOTAL truck trips per well (6 wells on 1 pad)	2195	450

Scenario 1: 150 wells over ten years results in an average of 15 wells/year. There will likely be simultaneous emissions from well completions at different pads at the same time, although the pads may be separated by a considerable distance. It is assumed these wells are on multi-well pads for total truck trips of 6,613 (2,645 trips X 2.5 well pads) per year. Furthermore, 225 hydraulic fracturing pumps will be in use annually to stimulate 15 wells (15 wells x 15 frac pumps/well) and those 15 wells could amount to 15 separate flaring events. In terms of frac tanks, there will be approximately 180 (72 tanks/pad x 2.5 pads) in use each year.

Scenario 2: 450 wells over ten years results in an average of 45 wells/year. There will likely be simultaneous emissions from well completions at different pads at the same time, although the pads may be separated by a considerable distance. It is assumed these wells are on multi-well pads for total truck trips of 19,838 (2,645 trips X 7.5 well pads) per year. Furthermore, 675 frac pumps will be in use annually to stimulate 45 wells (45 wells x 15 frac pumps/well) and those 45 wells could amount to 45 separate flaring events. In terms of frac tanks, there will be approximately 540 (72 tanks/pad x 7.5 pads) in use each year.

Literature Review of Air Impacts

Of all the UGWD steps considered for this risk assessment, the hydraulic fracturing step has likely elicited the greatest public concern, mostly due to undisclosed chemicals pumped into the ground during fracking and the potential for methane migration into groundwater as a result casing/cementing failures. However, the health effects of air emission are receiving increased attention. Review of the most recent reports ("Big Oil, Bad Air: Fracking the Eagle Ford Shale of South Texas") and studies (McKenzie et al., 2012; Field et al., 2014; Adgate et al., 2014; Eapi et al., 2014) conclude that UGWD air emissions create a potential for increased public health risks. They also highlight the scientific community's need for additional monitoring to better characterize exposures. Applicability of these current studies in Colorado and Texas to the Marcellus in Maryland is complicated by geological differences between formations and differences in the current or proposed regulatory frameworks.

Summaries of key air quality findings from the scientific literature are presented below and categorized under criteria or non-criteria pollutants.

Criteria Pollutants

Particulate Matter

Modeling exercises performed by the State of NY (NYSDEC, 2011) and the University of Michigan (Rodriguez& Ouyang, 2013) identified substantial particulate emissions from hydraulic fracturing pumps. New York's modeling found that hydraulic fracturing pumps meeting Tier II emission standards would still exceed both PM2.5 and PM10 standards (NYSDEC 2011, p. 6-143 and 144)) up to 150 meters and 60 meters away, respectively. The University of Michigan's analysis found that in both the Eagle Ford and Marcellus Shales, hydraulic fracturing pumps were responsible for more than 83 percent of the total combustion emissions associated with Hydraulic fracturing operations. Studies by the University of West Virginia School of Public Health for the WV Dept. of Environmental Protection (McCawley, 2013) also found particulate pollution levels from some well pads exceeding ambient air quality standards at a 625 foot set-back distance from the center of the well pad. Another study by the National Energy Technology Laboratories mobile air monitoring lab found significant increases in PM10 during hydraulic fracturing (Pekney, 2013). Esswein et al. (2013) found worker exposure to silica proppants exceeding occupational health criteria at all sites monitored. Some of these sites had greater than 10-fold exceedances. Although worker exposure is outside the scope of this RA this study indicates silica emissions are occurring and could be transported off-site.

NOx

The NETL study (Pekney, 2013) mentioned above found NOx peaks of 140-160 ppb on the well pad during hydraulic fracturing.

Ozone

Studies in Colorado (Pétron et al., 2012; Gilman et al., 2013), Texas, and Oklahoma (Katzenstein, 2003) have attributed increased ozone in nearby urban areas to emissions from UGWD activities. Another study (Kemball-Cook, 2010) in the Haynesville Shale region of East Texas and Louisiana projected ground level ozone concentration increases of up to 9 and 17 ppb under different emissions scenarios. Field et al. 2013 found methane and VOC concentrations from UGWD contributing to winter ozone exceedances in Sublette Co., Wyoming.

Non-criteria Pollutants

Benzene and Other Volatile Organic Compounds

The WVDEP found benzene concentrations during fracturing/flowback at some drilling sites in WV to be above minimum risk levels established by the Centers for Disease Control and that all sites monitored had detectable levels of Benzene, Toluene, Ethylbenzene and Xylenes (BTEX compounds) at 625 feet from the center of the well pad (McCawley, 2013). McKenzie et al. (2012) found that VOCs, including hydrocarbons, were higher near well pads than in residential areas, higher for residents within a half mile of the well pad than those farther, and were highest during well completion periods. The McKenzie study was conducted at sites that had uncontrolled flowback and also included the influence of diesel engines. Adgate et al. 2014 found other risk assessments confirming the McKenzie study conclusions with elevated lifetime cancer risks driven by benzene, some indication of acute or subchronic noncancer risks for those living closest to well sites, and little indication of chronic noncancer risks. Pilot studies in Colorado (CDPHE, 2010), Pennsylvania's Marcellus (PADEP, 2010) and Texas's Barnett Shale (Zielinska et al., 2011; TCEQ, 2012) indicate that VOCs (including benzene and formaldehyde) are emitted during well completions. EPA also recognizes the oil and gas industry is a significant source of VOCs during the well completion phase and has issued new rules to address this source (U.S. EPA, 2012). Coons and Walker 2008 found that benzene emissions from uncontrolled flowback posed the highest cancer and non-cancer risks to human health.

Hydrogen Sulfide and Methane

Significant health effects with hydrogen sulfide exposure occur at 100 parts per million (ppm) with lethal concentrations at approximately 1,000 ppm (Guidotti, 2010). New York State's (NYSDEC, 2011) modeling analysis of hydrogen sulfide was projected to violate the state standard (.01 ppm in any 1-hour period) without controls on well stack heights. In a self-survey of residents near UGWD activities in Pennsylvania, 81 percent of respondents reported odors (Steinzor et al. 2013) which are potentially due to hydrogen sulfide because it has a low odor threshold (>4.7 ppm, Eapi et al., 2014). Initial studies show (Eapi et al., 2014) that hydrogen sulfide concentrations can vary from site to site, but overall find no significant differences in concentration between wet and dry gas sites. This study also found hydrogen sulfide concentrations exceeding 4.7 ppm just beyond the fence line in 8 percent of lease sites, and a maximum measured concentration of 137 ppm. These concentrations are above a nuisance/odor threshold but not above concentrations expected to produce human health impacts for off-site (i.e., non-worker) populations.

Methane emissions also occur during flowback. Recent studies (Allen et al., 2013) indicate that methane emissions during flowback may be lower than current EPA estimates because of the use of capture equipment on site.

Other

Colburn (2014) measured other constituents (methylene chloride spikes up to 1730 parts per billion and summed composite polycyclic aromatic hydrocarbons (PAHs) at 15.5. nanograms per cubic meter, ng/m3) in air samples near UGWD operations. Cognitive impacts (lower mental development scores and IQs) from prenatal exposures of PAHs have been found at level from 2-4 ng/m3 and methylene chloride has been identified by EPA ["Methylene Chloride (Dichloromethane)"] as a probable human carcinogen. Colburn cited the source of methylene chloride as solvents used on-site for equipment cleaning purposes.

Risk Assessment

Risks from Combustion Sources

The probability of air risks from combustion sources is considered high in both scenarios as a result of combustion emissions from the large number of high horsepower/emissions hydraulic fracturing pumps used at each well site. University of Michigan studies indicate that hydraulic fracturing pumps account for greater than 80 percent of the emissions from UGWD. As to the consequences of these emissions, New York's modeling analysis showed Tier II hydraulic fracturing pumps still exceeding PM standard up to 150-meters away. Maryland's proposed 1,000-foot well pad setbacks from property boundaries and occupied buildings and minimum setback of 2,000 feet from private wells will help locate these emissions away from human receptors The CAA pre-empts Maryland from imposing emission standards on nonroad mobile engines that operate on a site for less than 12 months. Considering the BMPs, as well as the scope and duration of the hydraulic fracturing/completion phase, the consequences of air emissions from the hydraulic fracturing pumps are as follows: scenario 1 combustion emissions (Table 18) occur from 225 hydraulic fracture pumps operating over an estimated period of 75-days and are thus considered of minor consequence due to short duration and proposed BMPs; scenario 2 combustion emissions (Table 19) are expected to occur from 675 hydraulic fracture pumps for the better part of a year (i.e., 225-days) and thus of potentially moderate consequence given the duration, high fracture pump emissions rates even with CAA controls, and a higher potential for localized or temporary impacts. Due to the lower number of trucks used in this phase, the probability of emissions are considered moderate. There is currently insufficient modeling or fleet composition data to determine the consequences of vehicle emissions impacts. Consequences of dust/PM emissions from vehicle traffic are considered minor due to the relatively low volume of traffic during this phase.

There are also expected to be flaring emissions. Maryland's proposed BMPs prohibit flaring during well completion except if the content of flammable gas is very low, or when flaring is required for safety, limit flaring to no more than 30-days during the life of the well and require 98 percent combustion efficiency. Since studies indicate that combustion efficiencies are closer to 70 percent to as low as 15 percent in high wind situations and a 30-day maximum may be hard to enforce, flaring emissions are expected be of moderate probability. However, no studies were found to indicate flaring alone has anything more than minor consequences.

Risks from Noncombustion Sources

The literature review for this phase of UGWD identifies a high probability of noncombustion emissions during flowback, both from the well itself and tanks used to capture flowback water, as well as from the silica proppant during handling/mixing with hydraulic fracturing fluids. Although Maryland is expected to have dry gas, emissions from associated natural gas liquids may occur. It is possible that hydrogen sulfide gas may also be encountered with methane and New York's modeling efforts indicated potential exceedances of a state-specific standard that was mitigated by increasing stack heights or setbacks. The Departments are proposing to require reduced emissions completions (RECs) on all wells. In its Background Supplemental Technical Support Document for the Final New Source Performance Standards, (EPA, 2012). EPA estimated that REC could reduce the amount of VOCs released during hydraulic gas well completion by 95%. In a recent draft whitepaper, EPA stated “Based on the results reported by four different Natural Gas STAR Partners who performed RECs primarily at natural gas wells, a representative control efficiency of 90% for RECs was estimated.” Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas during Ongoing Production (EPA, 2014). Direct measurements of methane emissions at 27 well completion flowbacks found that “net or measured emissions for the total of all 27 completions are 98% less than potential emissions.” (Allen et al., 2013; PNAS, 2013). EPA recently issued emissions regulations on tanks that emit more than 6 tons of VOCs and Maryland is requiring these for all tanks upon startup. The New Source Performance Standard requires that VOC emissions from those storage tanks be reduced by 95% (40 CFR 60.5395). For purposes of this risk assessment, we are assuming that the recommended BMPs are followed; we acknowledge, however that the estimated efficiencies may not be achieved in all cases in the field and that the reduction efficiencies cited above have only been independently verified by one study using a limited dataset. Lastly, the setbacks will help minimize human exposures to all non-combustion emissions except those associated with vehicles.

Considering these proposed BMPs, the scope and duration of the hydraulic fracturing/completion phase, and potential for health effects identified in current literature from release of hazardous air pollutants during flowback, consequences are considered minor for scenario 1 (Table 18) but moderate under scenario 2 (Table 19), mainly as a result of the near year-round duration of scenario 2 noncombustion emissions. Further discussion of methane emissions in the context of global warming are discussed in Cumulative Impacts section below. Regarding silica emissions from proppant handling, consequences for both are also considered minor as the proposed BMPs and setbacks are expected to prevent significant exposures to human receptors off-site.

Risk from Accidents

Using the data in Table 18 and Table 19, provided by the Association of Oil and Gas Producers suggest 4.5 blowouts for every 10,000 wells drilled (9/20,328), resulting in a low probability of occurrence. The greatest risk from blowouts are to workers on site and is thus outside the scope of this risk assessment. The consequences to off-site receptors from a well blowout are considered minor.

Table 18: Scenario 1 Risk Assessment for Phase 4—Hydraulic Fracturing

*Global warming risk of methane not assessed (see Greenhouse Gases section)

Scenario	Activity/Duration	Annual Estimated Number of Emissions Sources/Loads	Emissions Type	Pollutants of Concern	Impact On	Probability	Consequence	Risk Ranking
Scenario 1	Hydraulic Fracturing during a total of 75 days	225 pumps (2,333 horsepower)	Combustion	NOx, PM, benzene	Human (Inhalation)	High	Minor	Moderate
		Silica proppant for up to 6 wells/pad	Non-combustion	Silica	Human (Inhalation)	High	Minor	Moderate
	Flowback during a total of 98 days	15 flaring events	Combustion	Carbon Dioxide, PM	Human (Inhalation)	Moderate	Minor	Low
		180 storage tanks, 15 venting and separation events.	Noncombustion	Methane*, hydrogen sulfide, VOCs/Natural Gas Liquids/BTEX	Human (Inhalation)	High	Minor	Moderate
		4.5 blowouts per 10,000 wells	Accidents/Spills	N/A	Human (Explosion)	Low	Minor	Low
	Not determined	6,613 truck trips per year.	Combustion	NOx, PM, benzene	Human (Inhalation)	Moderate	Insufficient data	Insufficient data
			Noncombustion	Dust/PM	Human (Inhalation)	Moderate	Minor	Low

Table 19: Scenario 2 Risk Assessment for Phase 4—Hydraulic Fracturing

*Global warming risk of methane not assessed (see Greenhouse Gases section)

Scenario	Activity/Duration	Annual Estimated Number of Emissions Sources/Loads	Emissions Type	Pollutants of Concern	Impact On	Probability	Consequence	Risk Ranking
Scenario 2	Hydraulic Fracturing during a total of 225 days	675 pumps (2,333 horsepower)	Combustion	NOx, PM, benzene	Human (Inhalation)	High	Moderate	High
		Silica proppant for up to 6 wells/pad	Non-combustion	Silica	Human (Inhalation)	High	Minor	Moderate
	Flowback during a total of 293 days	45 flaring events	Combustion	Carbon Dioxide, PM	Human (Inhalation)	Moderate	Minor	Low
		540 storage tanks, 45 venting and separation events.	Noncombustion	Methane*, hydrogen sulfide, VOCs/Natural Gas Liquids/BTEX	Human (Inhalation)	High	Moderate	High
		4.5 blowouts per 10,000 wells	Accidents/Spills	N/A	Human (Explosion)	Low	Minor	Low
	Not determined	9,825 truck trips per year.	Combustion	NOx, PM, benzene	Human (Inhalation)	Moderate	Insufficient data	Insufficient data
			Noncombustion	Dust/PM	Human (Inhalation)	Moderate	Insufficient data	Insufficient data

Phases 5 and 6: Production/Processing and Ancillary Infrastructure

Activity/Description

Pipeline systems are installed during this phase to connect wells to transmission lines. Prior to installation, pipes are delivered via trucks and are installed underground using ditch-diggers and other construction equipment. After installation, pipes can leak methane over time. Pipes can also be inadvertently ruptured during other construction-related activities creating an explosion/safety hazard. Compressors (Figure 9) may be necessary on site to provide proper gas pressurization and flow through pipelines. Offsite compressors are also required to maintain necessary pressures to deliver gas to a processing plant or transmission line. Internal combustion engines are typically used at gas gathering, boosting and compression and can be powered by raw or processed natural gas as well as by diesel fuel or gasoline.

Figure 9: On-Site Gas Compressor Station (Photo courtesy of the Colorado Oil and Gas Conservation Commission)

Periodic purging of liquids, referred to as unloading, is necessary to clear the well of any liquids that hinder flow of gas. Unloading can result in emissions of methane and any other constituents associated with the produced gas. In addition, produced gas may need additional processing to prevent condensation/crystallization of liquid compounds in the gas gathering lines. This processing may occur both on-site, known as field processing (Figure 10), and off-site at centralized processing plants. On-site heaters, oil/water/gas separators and dehydrators may be necessary before gas can enter a gathering line. Although the portion of the Marcellus in Maryland is expected to be mostly dry gas needing minimal, if any, processing, there may still be well to well variability in gas composition that makes some field processing necessary.

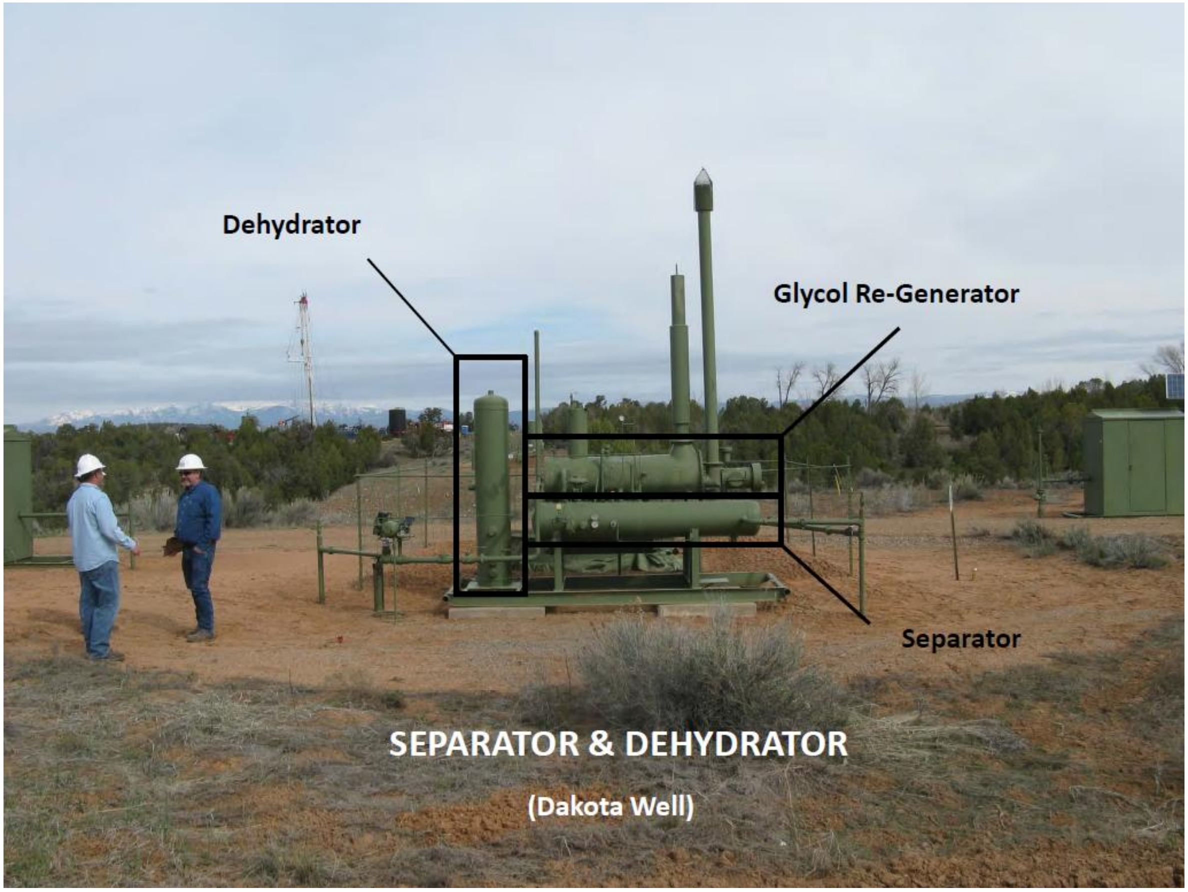

Figure 10: Field Processing of Natural Gas (Photo courtesy of the Colorado Oil and Gas Conservation Commission)

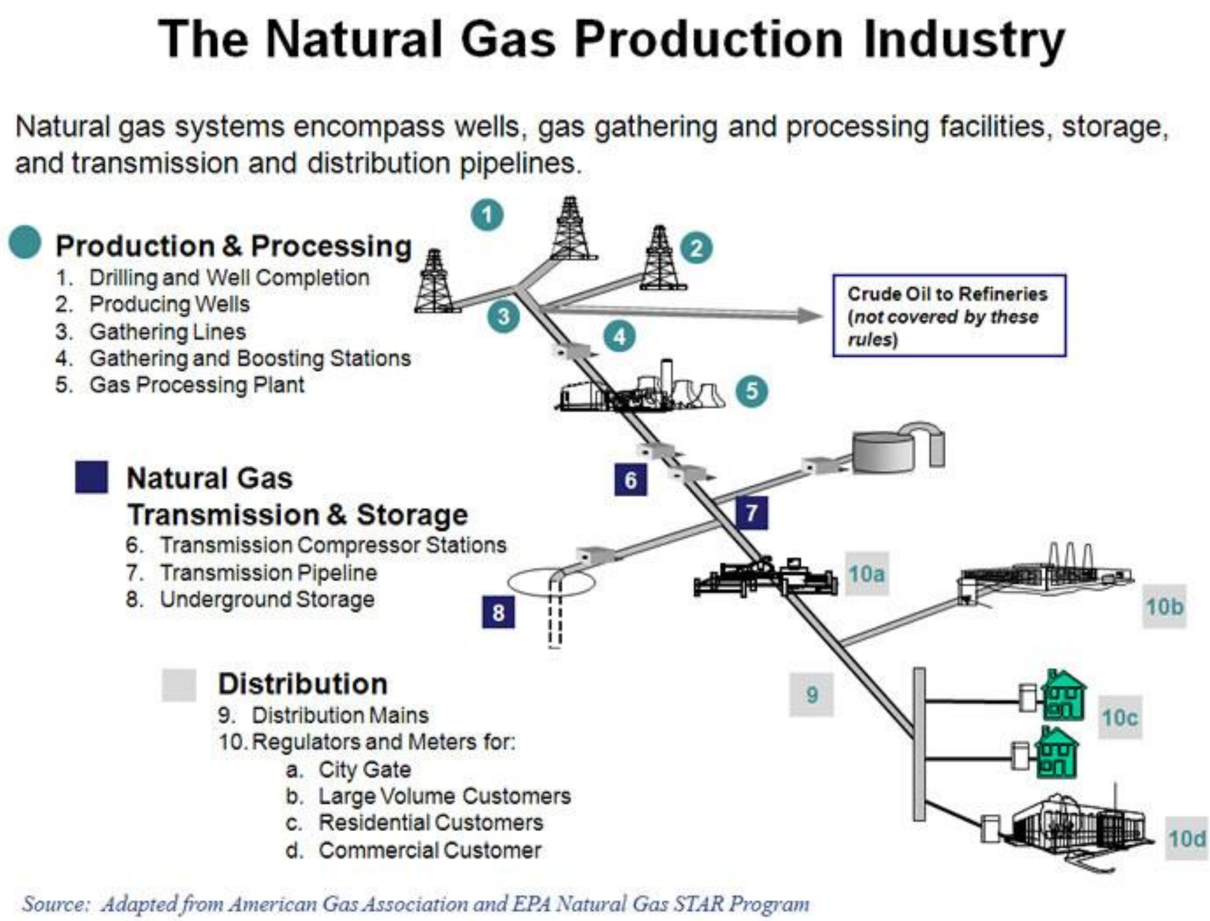

Figure 11: The Natural Gas Production Industry (Photo courtesy of EPA "Oil and Natural Gas Air Pollution Standards")

Emission Sources

For the purposes of this risk assessment, sources considered are limited to the well pad, an off-site compressor, and on-site gas gathering lines.

Combustion Sources
On and Off-site compressors

Non-Combustion Sources
Equipment leaks from pneumatic valves, pumps, flanges, gauges, and pipe connectors. (Alvarez & Paranhos, 2012)
On-site oil/water/NGL separator, dehydrator, and condensate storage tanks. (NYSDEC, 2011)
Well unloading (Allen et al., 2013)

Accidents/Spills
Well blowouts

Activity duration and Scope

Duration

Production declines over time, but each well is assumed to produce for 20 years or more. Some level of refracturing may also occur, extending the life of individual wells, but is not considered here.

Scope

One on-site and one off-site compressor per pad and one line heater (NYSDEC, 2011) operating over 10 years. Well pads may also have dehydrators, separators and condensate tanks to store NGLs, although the Maryland portion of the Marcellus is likely to be dry gas with little or no natural gas liquids. Well unloading in the Allen et al., 2013 study happened on avg. 6 times/year while the American Petroleum Institute/American Natural Gas Alliance survey EPA calculated an average unloading rate of 32.57 times/year.

Scenario 1: Peak combustion emissions from 50 compressors (1 on and 1 off-site multiplied by 25 pads) running simultaneously in Year 10. Peak well unloadings ranging from 900 – 4,886 (150 wells multiplied by 6 and 32.57 unloadings, respectively) in year 10 resulting in noncombustion emissions. Unquantified noncombustion emissions from site processing, condensate storage tanks and pipe leakage. Assume 825 (33 trips times 25 well pads) peak light truck trips/year for well unloading, to perform leak detection/repair, monitoring, and general site maintenance.

Scenario 2: Peak combustion emissions from 150 compressors (1 on and 1 off-site multiplied by 75 pads) running simultaneously in Year 10. Peak well unloadings ranging from 2,700 – 14,657 (450 wells multiplied by 6 and 32.57 unloadings, respectively) in year 10 resulting in noncombustion emissions. Unquantified noncombustion emissions from site processing, condensate storage tanks and pipe leakage. Truck trips at this stage are assumed to be predominately light trucks of relatively small number compared to the other phases. Assume 2,475 (33 trips times 75 well pads) peak light truck trips/year for well unloading, to perform leak detection/repair, monitoring, and general site maintenance.

Literature Review of Air Impacts

Criteria Air Pollutants

Combustion Emissions

In calculating criteria pollutant emissions associated with on and off-site compressors at a well pad, NY assumed a 2,500 hp on-site compressor running year-round resulting in 48.3 tpy NOx (NYSDEC, 2011, p. 6-101) and an off-site compressor with a 1,775-hp Caterpillar G3606 engine (NYSDEC, 2011, p. 6-107). NY modeling results did not project compressor noncompliance with ambient air standards for criteria pollutants.

Non-Criteria Pollutants

Combustion Emissions

NY estimated total VOCs and HAPs associated with off-site compressors to be 5 and 2.7 tons/year, respectively. They also modeled exceedances of their state-specific standard (i.e., annual guideline concentration or AGC) for formaldehyde emissions resulting from the off-site compressor. NY concluded that, in addition to required NESHAP controls required for compressors, limiting public access to at least 150-meters from the compressor would address remaining exceedances.

Non-Combustion Emissions

NY modeled exceedances of their AGC for benzene as a result of glycol dehydrators (NYSDEC, 2011, 6-140). EPA cites glycol dehydrators as the primary source of emissions at oil and gas production facilities, though downstream infrastructure is not assessed here ("Outdoor Air-Industry, Business, and Home: Oil and Natural Gas Production- Additional Information"). New York also noted that in cases where wet gas is encountered, there will be potential emissions of VOCs and HAPs (e.g., benzene) from condensate storage tanks. Coons and Walker 2008 modeled both cancer and non-cancer benzene exceedances resulting from uncontrolled emissions from glycol dehydration units and condensate tanks, but this study was done in Colorado where more wet gas is encountered. As detailed above in the hydraulic fracturing/completion step, the portion of the Marcellus underlying Maryland is comprised of the eastern-most portion of the play comprised of mostly dry gas. New York's SGEIS likewise anticipated mostly dry gas with little natural gas liquids. As a result, non-combustion emissions (BTEX or VOCs) are not expected to result from natural gas liquids and associated processing/production (NYSDEC, 2011, p. 6-105).

Allen et al. (2013) measured methane emissions resulting from equipment leaks during well production as well as during well unloading events. Overall, measured emissions from the study (957 gigagrams (Gg) methane ± 200 Gg) were found to be comparable to EPA's national emissions estimates (~1,200 Gg methane). This work focused specifically on leaks from pneumatic controllers/pumps as well as leaks from equipment, pipes, and fittings. Even though overall emissions estimates from this study were found to be similar to current national estimates, emission rates from specific equipment evaluated in the study varied significantly. For example, the study found that methane emissions from intermittent and low bleed pneumatic devices are anywhere from 29 percent to 270 percent higher than national emissions estimates. The study also found that the average number of well unloadings calculated from the 9 wells sampled (approximately 6 well unloadings/year) is much lower than averages from other studies, (approximately 32 unloadings/year)(API/ ANGA, 2012). The Allen study is important as it is one of the first studies of actual on-site emissions collected independently of industry derived estimates. The population of evaluated sites (150 production, 27 completion, 4 workover, and 9 unloadings sites), however, is limited in number and the sites were not randomly chosen. The wells were in different regions and, even within the same region, results varied due to differences in control equipment and natural gas composition. Also, some emissions sources, such as on-site tanks, were not evaluated during the course of study.

Risk Assessment

Risks from Combustion Sources

The probability of air risks from combustion sources is considered high in both scenarios as a result of combustion emissions from on and off-site compressors running year round for the assumed 20-year life of each well and light truck trips associated with well pad site visits. As to the consequences of compressor emissions, New York's modeling analysis from a single well pad that included one drilling and one off-site compressor indicated exceedance of their state-specific formaldehyde standard that was mitigated with a 150-meter setback. New York's modeling of only a single off-site compressor likely underestimates compressor emissions because Department staff observed up to 5 large compressors operating 24-hours a day at an off-site compressor station in West Virginia. New York's modeling was done before the new performance standards for compressors were promulgated. Maryland's proposed 1,000-foot setbacks of compressors from occupied buildings help locate compressors away from human receptors but data validating this setback distance are not available. Maryland is also considering emissions standards for equipment used on the well pad, but current CAA regulations pre-empt Maryland from implementation. If compressors are run on natural gas produced at the well pad, combustion emissions will be reduced. The comprehensive gas development plan (CDGP) will help locate compressor sites in the least impactful areas, but will not necessarily ensure coordination between companies in compressor locations.

On the consequences side, both scenarios result in simultaneous year-round combustion emissions from multiple well pads that build to a peak in year 10 before declining arithmetically to zero in year 20. Furthermore, uncertainty remains in terms of specific compressor locations, numbers, and fuel sources to confidently assign consequences. Conducting modeling analysis during CDGP development could further help minimize impacts from compressor combustion emissions. However, insufficient information exists at this time to determine overall consequences of compressor emissions for either scenario (Table 20). The consequences of combustion emissions from light trucks are considered minor in light of the relatively small number of vehicles, that they are light-duty (i.e., non-diesel), and have existing CAA controls.

Risks from Noncombustion Sources

The literature review for this phase of UGWD identifies a high probability of noncombustion emissions for both scenarios, mainly associated with emissions during well unloading and from equipment leaks from compressors, pneumatic valves, pumps, gauges and pipe fittings. In terms of assessing consequences, Maryland is expected to have dry gas with fewer natural gas liquids emitting BTEX or other harmful compounds. Where processing is necessary, Maryland's implementation of BAT is expected to minimize emissions of public health concern. It is possible that hydrogen sulfide gas may also be leaked but Maryland's setbacks are anticipated to mitigate any associated risks. Maryland is proposing leak detection and repair programs that should also help mitigate risks as long as they can be effectively enforced. Maryland is also requiring BAT systems for well unloading which are anticipated to have 70 percent emissions reduction efficiency. Finally, Maryland is proposing a requirement for methane emissions offsets that, in addition to the above BMPs, is expected to address methane emissions and associated risks. Discussion of methane emissions in the context of global warming potential are covered in Cumulative Impacts section below.

Considering these BMPs, and that few NGLs with potentially harmful pollutants are expected and/or of short duration, minor consequences are anticipated for noncombustion emissions. The greatest likelihood is for methane leaks that are not expected to pose a public health threat and which are discussed further in the greenhouse gas section below.

Risk from Accidents

Using the data in Table provided by the Association of Oil and Gas Producers suggests 4 blowouts for every 100,000 wells in production (8 per 211,142), resulting in a low probability of occurrence. The greatest risk from blowouts are to workers on site and is thus outside the scope of this risk assessment. The consequence to off-site receptors from a well blowout is considered minor.

Table 20: Risk Assessment for Phases 5 and 6: Production/Processing and Ancillary Infrastructure

*Global warming risk of methane not assessed (see Greenhouse Gases section)

Scenario	Activity/Duration	Annual Estimated Number of Emissions Sources/Loads	Emissions Type	Pollutants of Concern	Impact On	Probability	Consequence	Risk Ranking
Scenarios 1 and 2	20 years (peak emissions in year 10)	50-150 (annual peak) compressors	Combustion	NOx, PM, benzene	Human (Inhalation)	High	Insufficient data	Insufficient data
		25 – 75 (annual peak) well pads with emissions from pipes, valves, fittings, etc.	Noncombustion	Methane*	Human (Inhalation, explosion)	High	Minor	Moderate
		900 – 14,657 (annual peak) well unloadings	Noncombustion	Methane*, hydrogen sulfide, VOCs	Human (Inhalation)	High	Minor	Moderate
		4.5 blowouts per 100,000 wells	Accidents/Spills	N/A	Human (Explosion)	Low	Minor	Low
		825 – 2,475 (annual peak) light truck trips	Combustion	NOx, PM, benzene	Human (Inhalation)	High	Minor	Moderate
			Noncombustion	Dust/PM	Human (Inhalation)	High	Minor	Moderate

Risk of Cumulative Impacts or Synergistic Effects

The previous discussion divided the UGWD process into phases to help identify specific activities in each phase that have the greatest probability of occurrence and which may also result in the greatest consequences to public or environmental health. This stepwise approach allows the Department to target specific UGWD phases and emissions sources with the highest remaining risks and which may need further BMP controls. It is also necessary to look across all of the UGWD phases in a single view to determine whether there may be risks associated with cumulative impacts or synergistic effects.
Air pollution emissions during UGWD are unique compared to other potentially affected environmental media because these emissions occur during every phase of the UGWD process whereas water or land impacts will typically only occur if there is an accident, spill, BMP failure, or illegal disposal of drilling waste. Every single phase of UGWD relies upon internal combustion engines to either power equipment or deliver it to the site and once drilling begins methane itself may be emitted. Some emissions (compressors, productions leaks, condensate tank emissions, vehicles) will occur year-round, while other emission sources (noncombustion emissions during drilling, venting and flowback) are of shorter duration. Nearly all sources emit pollutants known to have human health risks (e.g., benzene) while emissions less problematic from a human health standpoint (e.g., methane) have climate change implications. In addition, certain pollution emissions (nitrogen oxides and VOCs) are already known to combine into constituents (ozone) with harmful health effects. Recent health risk assessments (McKenzie et al., 2012) have identified uncertainty regarding the public health impact of this complex chemical mixture. As a result, there is a high probability of emissions that overlap spatially as well as temporally and which singly, or in combination with other pollutants, have the potential to impact human health. Maryland's proposed BMPs and setbacks will minimize health and environmental effects, but by how much, under which scenarios and whether residual risks are ultimately acceptable cannot be determined without more rigorous, location-specific monitoring and modeling.

New York (NYSDEC, 2011) conducted a limited modeling exercise of emissions on the well pad and made some estimates of on-road vehicle emissions using vehicle miles traveled and number of truck trips from an Industry Information report. On this basis, NY concluded that NOx and VOC emissions would be relatively small and effectively mitigated for in their state implementation plan (SIP). Two important caveats to this modeling are that Maryland estimated twice the truck trips (1,000 per well) during hydraulic fracturing that NY assumed and the NY modeling did not include photochemical ozone formation. New York noted that "regional photochemical air quality modeling is a standard tool used to project the consequences of regional emission strategies for the SIP. The application of these models is very time and resource intensive. For example, these require detailed information on the spatial distribution of the emissions of various species of pollutants from not only New York sources, but from those in neighboring states in order to properly determine impacts of NOx and VOC precursor emissions on regional ozone levels. At present, detailed necessary information for the proper applications of this modeling exercise is lacking." (NYSDEC, 2011, p. 6-180) Furthermore, impacts associated with dust from heavy vehicle traffic on unpaved roads have not been quantitatively assessed by NY or in the scientific literature.

This lack of detailed modeling information coupled with the fact that empirical studies are finding increased ozone levels associated with UQWD sites, some contributing to ambient air standards nonattainment (Field et al., 2013), suggest that more information is needed in Maryland to determine cumulative impacts. Reducing the emissions of VOCs will reduce the possibility of the formation of ground level ozone. Garret County Maryland is currently attaining ambient air quality standards and thus falls under the prevention of significant deterioration part of the federal act. More information will be needed to determine if both significant deterioration of Garrett Co. air quality may occur or if air quality downwind in the Baltimore-Washington region ozone nonattainment may be exacerbated by UGWD.

Greenhouse Gases

According to the Environmental Protection Agency, the four most important greenhouse gases are carbon dioxide, methane, nitrous oxide, and fluorinated gases. Two of these gases, methane and carbon dioxide, are released during natural gas extraction. Methane is the primary constituent of natural gas and can be released during drilling, hydraulic fracturing, production/processing, and by leaks in pipes and valves. Carbon dioxide is the main component of emissions from internal combustion engines and is released whenever fossil fuels are combusted. Figure 12 below shows EPA estimates on the percent composition of greenhouse gases (GHGs) emitted in the U.S. during 2012.

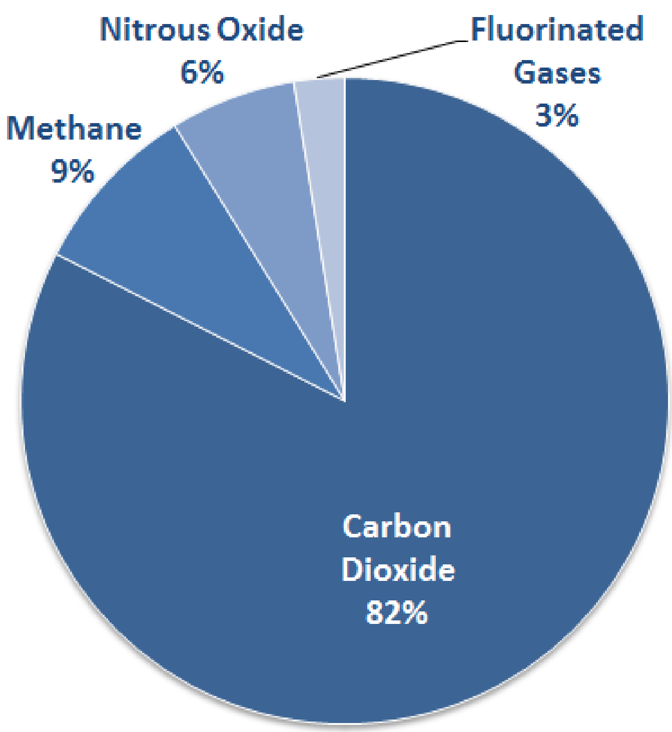

Figure 12: Composition of Greenhouse Gases in Percentages (Courtesy of EPA (http://www.epa.gov/climatechange/ghgemissions/gases.html)

According to EPA, methane has 21 times more global warming potential than carbon dioxide over a 100-year timeframe and studies (Alvarez & Paranhos, 2012) have found oil and gas development activities to be the largest U.S. source of methane emissions. Howarth (2012) suggests that when methane contributions from UGWD are considered over a shorter timeframe (20 years), they may be responsible for almost half of the warming impact from current emissions. A recent study by Brandt et al. 2014 reviewed technical literature from the last 20 years on natural gas emissions in the U.S and Canada and concluded: (1) EPA estimates consistently underestimate methane emissions with the oil and gas industry as consistent contributors; (2) a small number of "superemitters" may be responsible large emissions; (3) recent atmospheric studies showing large methane emissions are likely not representative of the oil and gas industry as a whole; and, (4) 100-year impacts from leakage is likely not large enough to outweigh natural gas benefits over coal.

In short, the scientific community is still divided on whether GHGs emitted during the production and transmission of natural gas outweigh the lower GHG emissions of natural gas when it is burned and over what timeframe. EPA's current emissions estimates were developed in the early 1990s and did not consider current extraction levels or UGWD techniques. Maryland's proposal to require rigorous leak detection systems and methane offset BMPs will help reduce overall emissions. However, to accurately assess whether UGWD creates an overall unacceptable risk to global warming, it will be necessary to empirically measure the life-cycle greenhouse gas emissions from other fuel sources, such as coal and petroleum, for relative comparison. This type of analysis would include analyzing different energy sectors across the country and recalculating life-cycle energy emissions inventories. Since this level of effort is outside the scope of this risk assessment, increased risks to global warming from shale gas extraction in Maryland has not been considered in this analysis.

Conclusions

Looking across the risk assessments for each phase there are several conclusions regarding risks. First and with the exception of the seismic assessment phase, there is a high probability of air pollution emissions during all UGWD phases even with BMPs in place. Secondly, most of these high probability emissions result from multiple, oftentimes overlapping combustion sources that for several sources (mobile sources, hydraulic fracturing pumps, and compressor emissions) have insufficient data or modeling information to reasonably determine consequences. Thirdly, for the two scenarios evaluated (150 and 450 total wells) there is not enough information to assess differences in risk during each UGWD phase. The only exception to this is the hydraulic fracturing/completion phase where both combustion and noncombustion emissions for the 450 well scenario are projected to occur over 60-80 percent of the year, respectively, compared to 20-27 percent of the year for a 150 well scenario. This results in the 450 scenario rated as having moderate consequences compared to minor consequences for a 150 well scenario.

These findings are consistent with other recent studies (Field, 2014; McKenzie, 2012) on air emissions impacts which conclude that air emissions from UGWD require further study and that site-specific assessments will be necessary to determine risk. They are also consistent with a recent report (2013) by the Office of the Inspector General on EPA's emissions estimates for the oil and gas sector which concludes that oil and gas production results in substantial emissions that can impact air quality and that there are currently limited direct emissions measurements. This situation hinders EPA's ability to quantify air impacts and assess health risks. Emissions rates and associated BMP efficiencies evaluated to date have largely been produced through voluntary industry reporting. As discussed above, only one study (Allen et al., 2013) was found where actual on-pad emissions were measured. However, this is a single study that relied on measurements taken at a limited number of sites and which highlighted significant geographical variability and measurement uncertainty that further emphasizes the need for location-based assessments.

Given the above conclusions and literature results, the overall probability for air emissions is high while the consequences cannot be determined at this time due to insufficient information on proposed BMP and setback efficiencies, combustion emissions impacts and photochemical transformation, specific location/density of wells/well pads, and potential for cumulative/synergistic effects.

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