Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program

Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and Other Low Permeability Gas Reservoirs

Agreement No. 9679

5 August 2009

Submitted to:

NYSERDA
17 Columbia Circle
Albany NY 12203-6399

Submitted by:
ICF Incorporated, LLC
2021 Western Avenue, Suite 104
Albany NY 12203

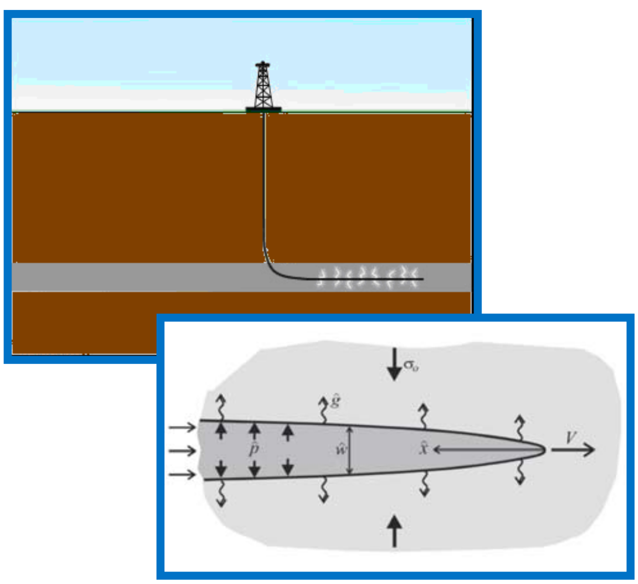


TABLE OF CONTENTS

INTRODUCTION: TASK 2 - TECHNICAL ANALYSIS OF POTENTIAL IMPACTS TO AIR

Shale gas reservoir developments are a growing source of natural gas production across the United States. The successful commercial model for shale gas development has been the use of horizontal wells and hydraulic fracturing stimulation as most easily demonstrated in the Barnett Shale of the Fort Worth Basin[1]. A shale gas play, in the early stages of production, is the Marcellus Shale of the Appalachian Basin, spanning parts of New York, Pennsylvania, West Virginia, and Ohio. The Marcellus Shale has the potential to be one of the largest shale natural gas plays in the United States, with Exhibit 2.1.1 showing gas reserves estimated at 1,500 Tcf or about five times as much as the Barnett Shale[2]. While the development of the Marcellus Shale is in the early stages, the use of horizontal well drilling and high volume hydraulic fracturing in this formation appear to be key to commercially developing this important natural gas resource.

Drilling operations, and especially multi-horizontal wells, are relatively new in Marcellus Shale. While drilling operations are underway in neighboring states as evidenced by over 450 wells in Pennsylvania for example, technical studies have yet to be published that quantify actual drilling operations in Marcellus Shale[3]. For the most part, we have had to make assumptions, where technically appropriate, that drilling operations in other shale formations are representative of expected Marcellus operations. Current industry players in the development of this formation have also been very helpful in providing information on their current experiences and by providing insight on their anticipated plans.

This task defines the drilling and completion phases associated with a gas extraction operation and provides information that may be used to assess the applicability of current air regulations and policies, as well as provide inputs for subsequent analysis of potential air quality impacts specific to Marcellus Shale.

The key focus will be on impacts associated with gas extraction by horizontal drilling and high-volume hydraulic fracturing techniques. This task discusses a generic gas extraction operation in terms of:

- Task (2.1) identifying key characteristics of a typical gas extraction facility and on-site equipment. Parameters outlined include site size, layout and duration of operations for an anticipated typical Marcellus site.
- Task (2.2) estimating potential air emissions from the equipment.
- Task (2.3) identifying possible pollutants and emissions factors for processes and equipment.
- Task (2.4) estimating indirect air emissions from hydraulic fracturing.
- Task (2.5) estimating emissions associated with extracted gas.
- Task (2.6) estimating emissions rates for all pollutants.

This review is intended to aid the New York State Energy and Research and Development Authority (NYSERDA) and the New York State's Department of Environmental Conservation

[1] All Consulting – *Modern Shale Gas Development in the United States: A Primer* www.all-llc.com/pdf/ShaleGasPrimer2009.pdf (Page 13)
[2] All Consulting – *Modern Shale Gas Development in the United States: A Primer* www.all-llc.com/pdf/ShaleGasPrimer2009.pdf (Page 17)
[3] Permit Workload Report: **http://www.dep.state.pa.us/dep/deputate/minres/oilgas/new_forms/Marcellus/Marcellus.htm**

(NYS DEC) in assessing the applicability of current air regulation and policies and to perform an analysis of potential air quality impacts. Information will be presented describing a “typical” site, and where feasible, a range of possible values will be provided to attempt to qualify the ambiguity involved in defining a “typical site” and hypothesizing a worst case scenario.

SUBTASK 2.1: IDENTIFICATION OF KEY CONSTRUCTION AND OPERATION PARAMETERS

While development of Marcellus Shale is in the early stages, the use of horizontal well drilling and hydraulic fracturing appear to be the key to the commercial success of developing this natural gas resource. This section will identify the size and layout of a typical gas extraction facility, on-site equipment and duration of processes. Discussion will assume all well sites are stand-alone entities. There is, however, some indication from current operators in Marcellus Shale of the consideration off-site dehydration facilities, compressor stations, and impoundments or lined pits to service multiple well sites. The section will close with a narrative on the construction and operational phases of a typical horizontal well that employs hydraulic fracturing during completion. The narrative will lay the groundwork for the more detailed research and analysis in the remaining sections. Exhibit 2.1.1 shows summary data for wells in a variety of shale basins.

Prior to 2008 legislative amendments, shale well spacing in New York was limited to 40-acre spacing units. Complete development of 1 square mile (one section or 640 acres) of Marcellus formation would then be limited to a maximum of 16 vertical wells. Alternatively, six to eight horizontal and fractured wells, drilled from a single well pad could exploit the same formation volume, or even more volume[4]. Other discussions indicate that 4 horizontal wells would appear to fully exploit a formation as successfully as 16 verticals within 1 square mile[5].

Given that the focus of New York's ongoing environmental review is on horizontal drilling and high-volume hydraulic fracturing, the following discussion will be based on that practice. After a review of current drilling operations and permit applications, it is postulated that a typical NYS Marcellus Shale site might have as few as 4 wells and but more typically as many as 6 horizontal wells. In some cases, as many as 8 horizontal wells may be drilled from a single pad in NYS Marcellus Shale.

[4] All Consulting – *Modern Shale Gas Development in the United States: A Primer* http://www.all-llc.com/pdf/ShaleGasPrimer2009.pdf (page 47-48)
[5] All Consulting – *Modern Shale Gas Development in the United States: A Primer* http://www.all-llc.com/pdf/ShaleGasPrimer2009.pdf (Page 47-48)

EXHIBIT 2.1.1: COMPARISON OF DATA FOR THE GAS SHALES IN THE UNITED STATES

Gas Shale Basin	Barnett	Fayetteville	Haynesville	Marcellus	Woodford	Antrim	New Albany
Estimated Basin Area, square miles	5,000	9,000	9,000	95,000	11,000	12,000	43,500
Depth, ft	6, 500 - 8,500[82]	1,000 - 7,000[83]	10,500 - 13,500[84]	4,000 - 8,500[85]	6,000 - 11,000[86]	600 - 2,200[87]	500 - 2,000[88]
Net Thickness, ft	100 - 600[89]	20 - 200[90]	200[91] - 300[92]	50 - 200[93]	120 - 220[94]	70 - 120[95]	50 - 100[96]
Depth to Base of Treatable Water[#], ft	~1200	~500[97]	~400	~850	~400	~300	~400
Rock Column Thickness between Top of Pay and Bottom of Treatable Water, ft	5,300 - 7,300	500 - 6,500	10,100 - 13,100	2,125 - 7650	5,600 - 10,600	300 - 1,900	100 - 1,600
Total Organic Carbon, %	4.5[98]	4.0 - 9.8[99]	0.5 - 4.0[100]	3 - 12[101]	1 - 14[102]	1 - 20[103]	1 - 25[104]
Total Porosity, %	4 - 5[105]	2 - 8[106]	8 - 9[107]	10[108]	3 - 9[109]	9[110]	10 - 14[111]
Gas Content, scf/ton	300 - 350[112]	60 - 220[113]	100 - 330[114]	60 - 100[115]	200 - 300[116]	40 - 100[117]	40 - 80[118]
Water Production, Barrels water/day	N/A	N/A	N/A	N/A	N/A	5 - 500[119]	5 - 500[120]
Well spacing, acres	60 - 160[121]	80 - 160	40 - 560[122]	40 - 160[123]	640[124]	40 - 160[125]	80[126]
Original Gas-In-Place, tcf[127]	327	52	717	1,500	23	76	160
Technically Recoverable Resources, tcf[128]	44	41.6	251	262	11.4	20	19.2

NOTE: Information presented in this table, such as Original Gas-in-Place and Technically Recoverable Resources, is presented for general comparative purposes only. The numbers provided are based on the sources shown and this research did not include a resource evaluation. Rather, publically available data was obtained from a variety of sources and is presented for general characterization and comparison. Resource estimates for any basin may vary greatly depending on individual company experience, data available at the time the estimate was performed, and other factors. Furthermore, these estimates are likely to change as production methods and technologies improve.

Mcf = thousands of cubic feet of gas
scf = standard cubic feet of gas
tcf = trillions of cubic feet of gas
# = For the Depth to base of treatable water data, the data was based on depth data from state oil and gas agencies and state geological survey data.
N/A = Data not available

Source: All Consulting – Modern Shale Gas Development in the United States: A Primer www.all-llc.com/pdf/ShaleGasPrimer2009.pdf (Page 17)1. Footnotes in table corresponded to the original document.

2.1.1 Well Pad Size

Multi-well horizontal drilling and high volume fracturing operations are relatively new in the Marcellus Shale and studies have yet to be formally published that detail actual operations in this formation. An assumption that drilling operations in other shale formations are representative of future Marcellus operations is required in light of the lack of literature on actual Marcellus Shale drilling. In addition, some insight can be gained from discussions with operators currently active in this formation in adjacent States, review of recent SGEIS information requests and review of current drilling applications made to NYS.

In an Environmental Assessment published for the Hornbuckle Field Horizontal Drilling Program (Wyoming), the well pad size required for drilling and completion operations is estimated at approximately 460' by 340' (~3.6 acres) in overall size[6]. This estimate does not include areas disturbed due to access road construction. A study of horizontal gas well sites constructed by SEECO, Inc in Fayetteville Shale, reports that operators generally clear an area 300' by 250' for a pad and lined pits. These sites may be as large as 500' by 500'[7] (5.7 acres).

Informal discussion with a current operator suggests that an initial and single well horizontal well-pad size in the Marcellus Shale might start out as a site 350' by 400'. Furthermore, the same operator suggested a "rule of thumb" to consider a nominal 50' increase in the size of the pad to accommodate each additional well drilled in a multi-well operation (e.g. 350' by 450' for two wells)[8]. Extrapolating to six wells would then require a pad of slightly more than 5.2 acres.

Ultimately, pad size is determined by site topography, number of wells and pattern layout with consideration given to the ability to stage, move and locate multiple drilling and hydraulic fracturing equipment. Timing of individual well drilling and completion events may also influence demands on pad size. In addition, placement of construction equipment and material lay-down and storage may influence pad area needs. Location of lined pits, tanks, hydraulic fracturing equipment, reduced emission completion equipment, dehydrators and production equipment such as compressors and associated control monitoring as well as office and vehicle parking requirements can add square footage requirements. Incorporation of shared equipment servicing multiple pads can add to pad size requirements. Likewise, availability and access to offsite dehydrators, compressor stations and centralized lined pits or impoundments may reduce the well pad size. NYS DEC mandates on setbacks may also impose additional square footage requirements.

Recently Chesapeake Energy submitted applications for 23 gas wells to be drilled in Delaware County. These proposed wells would be drilled on 4 separate well pads, each consisting of nominally 6 wells. According to the application documents, the average well pad side during construction is 300' by 300', not including an additional 45'

[6] Bureau of Land Management: Wyoming – Hornbuckle Field Horizontal Drilling Program http://www.blm.gov/pgdata/etc/medialib/blm/wy/information/NEPA/cfodocs/hornbuckle.Par.11552.File.dat/ch2.pdf
[7] Argonne national Laboratory: EVS – Trip Report for Field Visit to Fayetteville Shale Gas Wells http://www.evs.anl.gov/pub/doc/ANL-EVS_R07-4TripReport.pdf
[8] Jared Hall (East Resources Inc.) General Mgr. – Teleconference @ 2p.m. 4/13/09

by 140' for lined pits. After completion, the well pad would be shrunk to 200' by 250' through land reclamation.[9]

In summary and reasonably substantiated by the three active Marcellus Shale operators in response to queries by NY DEC SGEIS information requests, it would appear to suggest, for planning purposes, that a minimum multi well (6-8 wells) pad size to be around 300' by 350' (2.4 acres) with a typical site 400' by 500' (4.6 acres) and a maximum pad size of 500' by 500' (5.7 acres). The following sections will specify, in greater detail, the various features of a well site during the different phases of gas extraction.

2.1.2 Restrictions to Public Access

The Marcellus Shale well sites will be situated in locations diverse in proximity to urban centers or rural and remote environments. All 23 horizontal gas wells proposed in the Chesapeake Energy Delaware County applications are located in rural and forested areas that are distant from population centers, but in proximity to public roads. The access roads for these wells range from 130' to 965' long[10].

The 1992 GEIS[11] suggests that site requirements stipulate a list of provisions for the purpose of public safety implicit to which includes limitation of public access. These steps appear adequate and acceptable in restricting access to the Marcellus sites as well. Additional consideration should be given to stipulating the use of locks on gates, equipment and valving when left unattended. Given the evolution of remotely monitored surveillance and intrusion sensing equipment since 1992, thought should also be given to its use on drilling and production sites. Consultation with State and local policing authorities would be advised to determine the need for such extra security measures.

2.1.3 General Layout

Assessment of potential air emissions requires an understanding of the specific features and equipment on a typical well site during its various operational phases. The 1992 GEIS provides lists of equipment used at a typical well site. These lists were corroborated with equipment lists for existing horizontal drilling operations[12,13] and input from subject matter experts, to determine the equipment used in different phases of a typical gas extraction operation.

The equipment list was compared against responses received from three Marcellus Shale operators in response to NYS DEC SGEIS information requests[14]. Exhibit 2.1.2 is the list of features to be expected at a typical well site recognizing that some equipment may be present for only parts of the construction, completion and

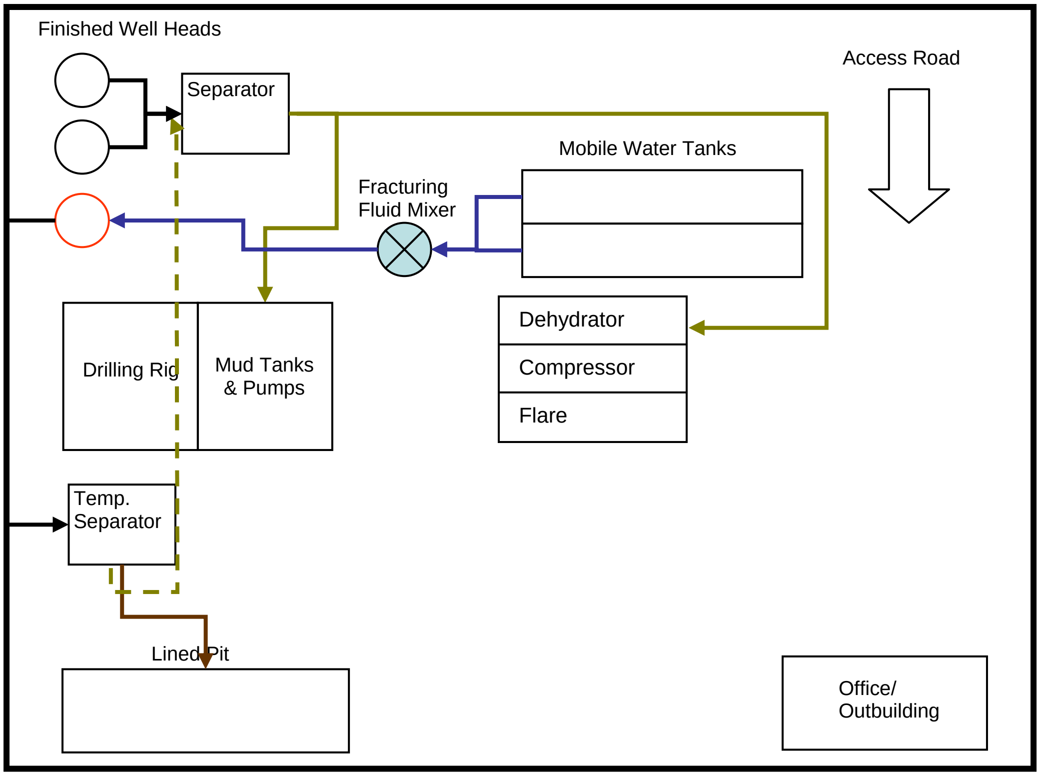
[9] Chesapeake Energy's Delaware County Marcellus Applications made for 23 wells on 4 well pads.
[10] Survey of well permit applications from Chesapeake Energy's Delaware County Marcellus Applications
[11] Page 8-3 though 8-6 of the 1992 GEIS under section 5. Lease Terms
[12] Bureau of Land Management: Wyoming – Hornbuckle Field Horizontal Drilling Program http://www.blm.gov/pgdata/etc/medialib/blm/wy/information/NEPA/cfodocs/hornbuckle.Par.11552.File.dat/ch2.pdf
[13] Argonne national Laboratory: EVS – Trip Report for Field Visit to Fayetteville Shale Gas Wells http://www.evs.anl.gov/pub/doc/ANL-EVS_R07-4TripReport.pdf
[14] NY DEC SGEIS Information Request Responses from Fortuna, Chesapeake and East Resources with regard to Marcellus Shale

production processes. Exhibit 2.1.3 provides a simple schematic showing the general layout of a typical well site. However, layout can vary significantly by location, project scale and the operator's best practices. This diagram is based upon the best judgment of ICF internal experts and assumes no use of shared off-site equipment.

Exhibit 2.1.2: List of Equipment Expected at Typical Well Site

Timeframe	***Equipment***
Construction	
5-30 days/pad	Construction Equipment
Drilling	
12-14 days/well	Small Rig for Vertical Portion
12-14 days/well	Large Rig for Horizontal Portion
Completion: Fracturing Stimulation & Flowback	
30-45 days/total stimulation & flowback	Pump Trucks: Fluid preparation and Fracturing
30-45 days/total stimulation & flowback	Portable Water Tanks or Frac Tanks; Sand Storage Tanks & Trucks; Chemical Containers/Tanks & Trucks
30-45 days/total stimulation & flowback	Fracturing Fluid Plug
30-45 days/total stimulation & flowback	Perforating Gun
30-45 days/total stimulation & flowback	Frac Tanks or Lined Pits Trucks for outhaul of flowback fluids and solids
30-45 days/total stimulation & flowback	Technical Frac Monitoring Office/Truck including associated instrumentation
30-45 days/total stimulation & flowback	Flare(s)
All Phases	
Months	Lined Pits
	Piping
Years	Compression: typically multiple units
	Dehydrator: typically multiple units
	Pressure Control & Metering Equipment
	Heater Treater

Exhibit 2.1.3: Schematic of Typical Multi-Well Site



Not to scale (derived from footnote ***13*** plus expert judgment)

2.1.4 Time Frame of Construction Activities and Operations

Due to the longer drilled lengths typically associated with horizontal wells and the higher volume hydraulic fracturing process, the duration of well drilling and completion operations is usually longer than that associated with a single vertical well.

The Wyoming EIS for the Hornbuckle Drilling Program provides duration estimates for both drilling and completion activities for a horizontal, hydraulically fractured well. However, these are estimates for wells are being drilled in the Sussex formation, which has significantly different geological characteristics than the Marcellus Shale in New York. Wyoming EIS operational time lengths are:

• Rig transport and on-site assembly	7 days/well
• Drilling operation: to target depth and lateral section	35 days/well
• Completion activities for a single horizontal well	30 days/well
• Total for horizontal & hydraulically fractured well	72 days/well

Drilling duration for a Marcellus Shale operation may be longer due to the depths involved as well as the longer lateral section that must be drilled. Completion of the well may also require more time since the shale must be hydraulically fractured in multiple stages with each stage adding time to complete. Hence, if a single well requires 72 days to drill and fracture, it could take over a year to sequentially drill and fracture six wells on a multi-well site, in addition to the time required for site assembly.

It is possible that time efficiencies can be gained by completing an entire pad well-by-well in sequence, i.e. simultaneously drilling a new well and completing a well just drilled. A conservative worst-case emissions scenario would be to neglect these efficiencies and economies of scale since they are only 7 days or about 5% of the timeline. Equipment spacing constraints may or may not allow drilling two or more wells on a pad simultaneously. Hydraulically fracturing two or more wells at a pad at the same time may be possible by alternating the pumping between wells and this would reduce time and expense of multiple equipment mobilizations but this procedure would not lessen the total time required for hydrofracking operations.

This report is depicting a worst case emissions scenario as successive drilling and completion of 8 wells at a pad. In practice, some pads may not be fully developed in one consecutive period of time, but from an emissions standpoint this is not a worst case scenario. According to some Marcellus Shale operators, operators may drill 1 or 2 initial wells on a pad, and then drill the remaining 4 – 6 wells up to 2 years later, once the productivity of the well site has been determined[15]. However as drilling and completion experience as well a better understanding of the formation characteristics matures, operators will move to expedite full utilization of a pad site. This also requires market conditions for natural gas support new production.

The duration discussion above validates the preliminary estimates made for 23 wells proposed by Chesapeake Energy in Delaware Country. The applications estimate[16]:

.

• Rig transport and on-site assembly	5 – 30 days/well
• Drilling operation: to target depth and lateral section	20 – 30 days/well
• Completion activities(fracturing, flowback & testing) for single horizontal well	35 – 65 days/well
• Total for a single horizontal, hydraulically fractured well	60 – 125 days/well

Based on these applications for proposed wells and the previous discussion on durations, the above timing can be considered as mostly likely representative of early phases of Marcellus Shale drilling and completion. As evidenced in other formation evolution, timeframes may be reduced as operating efficiency and experience evolves.

Having outlined the various features present on a typical well site, as well as estimates of the timing, the following section will describe the main operational phases involved. A typical operation involves four main phases, site construction, drilling, completion and production. The following will discuss drilling and completion. The additional phases of well siting and pad construction (before drilling) and well production (after completion) will not be discussed since they were reviewed as part of the 1992 GEIS.

[15] NY DEC SGEIS Information Request Responses from Fortuna, Chesapeake and East Resources
[16] Received from Carrie Friello (DEC): Summary of Chesapeake – Delaware County applications for 23 horizontal well

2.1.5 Equipment and Process Used

2.1.5.1 Drilling

The 1992 GEIS states that most New York State wells employ a single rotary rig for drilling operations. These wells typically use either pressurized air or water to lift cuttings for shallow wells, or drilling mud for deeper wells. Since multi-well horizontal drilling programs are relatively new to the Marcellus Shale, detailed literature in the public domain on actual drilling practices cannot be found. Hence, common practices for similar wells in comparable gas shale formations were used in developing a narrative for drilling and completion activities.

Generally, horizontal wells can be drilled with a single rotary rig, though depending upon the depth and characteristics of the formation and rig availability, multiple rigs may be used. Typical horizontal wells in the Fayetteville Shale are known to use air-drilling rigs for the vertical portion of the well, with water-based mud and oil-based mud used to drill the horizontal section. The operators may use different drilling rigs (small and large) for the vertical and horizontal sections, with separate lined pits for each drilling fluid[17]. Chesapeake Energy's Delaware County applications similarly propose and validate the Fayetteville example by the use of air and mud drilling fluids. After rotary drilling the vertical portion of the well on air, operators switch to a down-hole drilling motor, powered by the flow of mud through the drill string, to begin an angle-building process. The distance drilled from the bottom of the vertical portion (known as the kick-off point) to where the well becomes horizontal is roughly a quarter mile[18]. The Chesapeake wells estimate is roughly 330 feet of vertical distance between the kick-off point and the depth at which the lateral portion begins. These wells average a total vertical depth of roughly 6,500 feet.

A cemented surface casing isolates all proximal, fresh water aquifers during drilling. Intermediate casing strings, if used, may also be cemented in place to eliminate the possibility of downhole fluid contamination. The lateral lengths in a typical horizontal shale gas well range from 1,000 feet to more than 5,000 feet[19]. Once the target depth is reached, with the drilling fluid flushed out, the operator initiates well completion activities.

2.1.5.2 Completions

Once the well has been drilled, it is extensively tested to determine the necessary steps to fully exploit its potential to produce a commercially viable volume of pipeline quality gas. A thorough process of field data collection and analysis is also done to allow the operator to understand the geology of the specific location, and to assess how fractures may develop in the shale formation during the hydraulic fracturing process. Based on the data, operators develop fine-tuned fracturing programs that use different blends of water/polymer and sand combinations that are specific to the formation. Since shale gas is held in a low permeable medium, it is necessary to fracture the shale so that the gas has a pathway from the shale to the well bore. Because of the length of the exposed well bore, it is usually not possible to maintain a downhole

[17] Argonne national Laboratory: EVS – Trip Report for Field Visit to Fayetteville Shale Gas Wells http://www.evs.anl.gov/pub/doc/ANL-EVS_R07-4TripReport.pdf
[18] Petrocasa Energy Inc. – Horizontal Drilling and Completion Video http://www.petrocasa.com/
[19] All Consulting – Evaluating the Environmental Implications of Hydraulic Fracturing in Shale Gas Reservoirs http://www.all-llc.com/shale/ArthurHydrFracPaperFINAL.pdf

pressure sufficient to stimulate the entire length of a lateral in a single stimulation event. Hence, hydraulic fracture treatments of shale gas wells are performed by isolating portions of the lateral and performing multiple treatments to stimulate the entire length of the lateral portion of the well.

The 1992 GEIS described the use of a water-gel based fluid for hydraulic fracture stimulation. Today, there are a much wider variety of fracturing fluids available with a range of blends and additives involved. Most horizontal well drilling programs mention the use of "slickwater" as a frac fluid. This is water with some additives to help prevent wellbore damage, reduce friction, and effectively place the proppant into the induced fractures. The exact nature of additives may be propriety information of the operating company or service provider. Task 1 provides a detailed discussion of hydraulic fracturing fluids and the issues associated with their use.

Each fracture stage in a fracturing program is performed within an isolated interval of the well lateral starting at the extremity of the well bore. The length of the horizontal section of the well is divided into several sections by plugs or well packers. One type of packer used for zonal isolation is a ball packer. It works by having a steel ball pumped into a seat point typically located where the last fracture stage was completed[20]. The ball acts as a sealing agent to the previously treated zone.

The outermost section is fractured first. First a perforating gun is lowered into the well and used to create a cluster of perforations in that section of the well bore. Then water is injected at increasingly higher pressure until a pressure chart shows the bottom-hole pressure makes a sudden drop, indicating that the rock has fractured. At this point, sand and additives are added to the injected water, and the pressure is maintained until a desired degree of fracturing is completed. In some fracture treatments, two or more sizes of proppants are used to optimize the propping of fractures at various distances from the well bore. Hence, a single isolated zone may undergo multiple sub-stages of hydraulic fracturing with the number of sub-stages being determined by the volumes of proppant and fracture fluid designed for the fractured treatment. Once the outermost section has been completely fractured, it is isolated using the packer or plug. Fracturing then begins on the next section. The process is closely monitored to make sure the well is fractured to the desired dimension, for optimal gas flow.

An entire fracture job may use between 50,000 to 80,000 bbl of water and 1 to 1.5 million lb of sand[21]. Following the fracture job, the isolation plugs in the lateral portion of the well are drilled out and flow-back occurs where water and spent additives used in the frac fluid begin to come back out of the well. Flowback rates can be 100 to 150 bbl per hour for shale wells that have been hydraulically fractured. This rate declines over time, with the flow-back water either being collected in 500 bbl frac tanks[22] or in lined pits. This can pose handling issues due to entrained natural gas as well as the presence of frac fluids and solids including sediments, sand (proppant) and sometimes naturally occurring radioactive materials (NORM). The frac fluid, once brought back to the surface is either disposed or reused. Chesapeake Energy's Delaware County application

[20] All Consulting – Evaluating the Environmental Implications of Hydraulic Fracturing in Shale Gas Reservoirs http://www.all-llc.com/shale/ArthurHydrFracPaperFINAL.pdf
[21] Argonne National Laboratory: EVS – Trip Report for Field Visit to Fayetteville Shale Gas Wells http://www.evs.anl.gov/pub/doc/ANL-EVS_R07-4TripReport.pdf
[22] Argonne National Laboratory: EVS – Trip Report for Field Visit to Fayetteville Shale Gas Wells http://www.evs.anl.gov/pub/doc/ANL-EVS_R07-4TripReport.pdf

indicates the use of membrane lined pits to store drilling fluids as well as flowback from fracturing. However, supplemental information provided by Chesapeake Energy indicated the use of steel tanks to capture flowback. Regardless, drilling and flowback fluids will be removed from their respective storage for proper disposal off site. Production brine will be stored in tanks for future disposal. Once the flow-back is finished, a work-over rig is used to install production tubing in the well.

2.1.5.3 Reduced Emissions Completions

For completions in general, the flow-back from the fracturing process lifts excess sand, gas and fluids to the surface and clears the well-bore. Gas/liquid separators used for normal production operations are not designed for these initial high liquid flow rates and cannot be used to recover gas that may come up during flow-back. The common practice is to flow the well to lined pits and/or tanks, where any gas is either vented or flared. The gas released to the atmosphere during the duration of the completion of a gas well may be as much as 10,200 Mcf per well[23], based on data from 25 wells completed in the Fort Worth Basin. Reduced emission completions (REC) allow the operator to recover much of this gas and deliver it to a sales line.

RECs use portable equipment designed specifically for handling the high volume of the initial flow-back water from the well. Sand traps are used to remove the finer solids in the stream and a plug catcher removes large solids such as drill cuttings. A portable desiccant or glycol dehydrator may be used to dehydrate the gas during completion, with a compressor, if required, used to send gas to the gas gathering or sales line. All needed equipment is mounted on a portable REC skid with temporary piping used to connect it to both the well and the gathering system.

While RECs have been found to be economically viable and environmentally beneficial, its application is far from universal. Utilization has been limited by operator familiarization with the process, availability of REC equipment and state pipeline regulation. It would appear that all of the above issues face operators in New York State using RECs. New York's current policy appears to require wells to be fully completed before construction of gathering lines and routing of gas to sales. RECs, as part of the completion process, produce commercial quality gas which can be routed directly to sales line, if available, rather than vented or flared. Operators may also be reluctant to install a sales line until conformation of a well's commercial viability in terms of production volume. In multi-well operations, operators could install a sales line after proving the first well, hence allowing the use of REC skids for the remaining completions on the well pad. For sites close to population centers, RECs may also be an option versus flaring or venting. The proposed Chesapeake applications make no mention of the use of RECs[24].

Subtask 2.1 has outlined construction and operational parameters of a typical horizontal well site for Marcellus Shale. These assumptions are summarized in the table below, calculated both for single/multiple well sites, as well as sites with/without RECs.

[23] Draft EPA Lessons Learned – Reduced Emissions Completions public data. Figure is based on an average of gas vented for 25 wells in the Fort Worth Basin (Barnett Shale) from 2004-05
[24] Chesapeake's Delaware County Marcellus Applications made for 23 wells on 4 well pads.

Exhibit 2.1.4: Matrix of Possible Scenarios for a Typical NYS Marcellus Shale Well Site

	Reduced Emissions Completions	
Number of Wells	*REC Not Implemented*	*REC Implemented(assumes access to sales gas line)*
Single	**Well Pad Size:** 300' x 350' **Duration:** Drilling: 30 days Completion: 30 days **Equipment:** See Exhibit 2.1.1	**Well Pad Size:** No significant change **Duration(not additive):** Drilling: 30 days Completions: 30 days (setup time for additional equipment assumed to be achievable simultaneously, within the duration of well development without RECs) **Additional Equipment:** A portable truck-mounted skid with sand trap, glycol dehydrator, compressor and piping **Savings:** up to 90% of gas vented during completion process
Multiple (6 Wells)	**Well Pad Size:** 500' x 500' **Duration: (per well)** Drilling: 30 days Completion: 30 days **Equipment:** See Exhibit 2.1.1	**Well Pad Size:** No significant change **Duration(per well & not additive):** Drilling: 30 days Completions: 30 days (setup time for additional equipment assumed to be achievable simultaneously, within the duration of well development without RECs) **Additional Equipment:** A portable truck-mounted skid with sand trap, glycol dehydrator, compressor and piping **Savings:** up to 90% of gas vented during completion process

Subtask 2.2: Identification of Equipment Used

Subtask 2.1 identified key construction and operations parameters. This section provides a further in-depth review of equipment used in horizontal drilling and high-volume hydraulic fracturing techniques in the Marcellus Shale covering types and number of units as well as which pollutants can be emitted from their use.

2.2.1 Equipment Types and Possible Emissions

The following list of equipment used (Exhibit 2.2.1) is an expanded, in-depth look at the equipment list in Exhibit 2.1.2 for a gas well pad in general. It includes all equipment types used for the duration of a typical gas extraction in general, from site construction and drilling, to completion and production, as well as a short description and identification as a potential emissions source. Some emissions source categories are less pronounced in NYS Marcellus Shale; for example, VOC emissions are minimal given the NYS Marcellus Shale gas compositions of very high methane content. Specific factors are given later in this narrative, and potential sources are identified here. Further discussion on potential emissions will follow in Subtask 2.3 thru Subtask 2.6 including their specific pollutants. Discussion will also include potential emissions source equipment, such as non-road engines (bulldozers and backhoes), road engines (including frequency and use), and stationary sources (diesel engines, storage tanks, housing units, or flares).

Exhibit 2.2.1: Generic Equipment Types and Possible Emissions

Use	Subtask Section #	Equipment	Description	Emissions Source for Typical U.S. Operations
Construction	**C1**	Construction Equipment	Off-road vehicles, such as backhoes, bulldozers, and other types of construction equipment will be needed to prepare the well site; access roads will be present in the initial stages of well site development.	Combustion, Particulate Matter
Drilling	**--**	Catwalk	A long, flat, steel platform where pipe is laid before it is pulled up through the v-door and placed into the mousehole.	--
	--	Crown Block	Device comprised of sheaves and pulleys at the top of the mast over which the drilling line is run down to the hoisting drum	--
	--	Derrick Board	Platform on the mast	--
	--	Drawworks	Large winch on the drilling floor which uses steel rope to raise or lower drilling equipment	--
	--	Driller's Console	Control panel on the drilling floor; used to monitor drilling operations	--
	--	Fuel Tank	Storage tanks that hold the diesel fuel used for the power system	VOC's/Venting/Fugitives
	--	Hydraulic/Air Hoists	Small cable crane that lifts pipe up the v door; personnel for maintenance	--
	--	Mast	Portable metal tower raised into working position; used for hoisting	--
	--	Mouse Hole	Hole in the drilling floor; used to store drillpipe until it is pulled up and attached to the drillstring	--
	C2	Mud Return Line	A conveyance for drilling mud as it returns to the surface[25]	Fugitives, VOC's
	C3	Mud System	The equipment that separates the earth cuttings coming out of the wellbore and continues the circulating fluid back to the wellbore	Fugitives, VOC's

[25] OSHA. www.osha.gov/SLTC/etools/oilandgas/illustrated_glossary/mud_return_line.html

Use	Subtask Section #	Equipment	Description	Emissions Source for Typical U.S. Operations
	C4	Mud-Gas Separator	A vessel that is attached to the mud flowline (#8) to remove gas from the circulated mud when drilling through a high pressure gas zone	Fugitives, VOCs
	C5	Mud Pit/Lined Pits	Also known as a "reserve pit"; is plastic-lined. An open excavation near the drilling rig that holds used or waste mud and cuttings.	VOC's
	C6	Mud Pumps	A set of two or three piston-driven pumps that are used to move circulating fluids on a rotary drilling rig	VOC's, venting, fugitives
	C7	Choke Manifold	A series of pipes and valves to control pressures experienced during a kick once the blowout preventers are closed.	Fugitives, Venting, VOC's
	--	Iron Roughneck	Hydraulic powered wrench to make up or break out pipe joints	--
	--	Pipe Rack	Steel platforms placed near the Catwalk that hold reserve drill pipe	--
	--	Standpipe	Seamless, vertical steel pipe carries drilling mud up to the rotary hose of the swivel	--
	C8	Accumulator	A tank which holds hydraulic fluid (not hydraulic fracturing fluid) stored under pressure by compressed nitrogen and used to actuate the BOP.	VOC's
	--	BOP Controller	Control panel on the drilling floor; used to remotely and independently control and operate each preventer on the BOP stack	--
	C9	BOP Stack	Stands for blowout preventer stack. It is attached to the wellhead under the rig floor and utilizes vertically arranged closing elements to either close off the well or control the release of fluids to and from the wellbore	Venting, Methane, Fugitives
	--	Rotary Table	Motorized circular platform in the rig floor which rotates all the pipe (i.e. drilling the hole)	--
	--	SCR House/Generator	Breaker house; electrical housing unit to power the rig site	Combustion
	--	SCR House/Top Drive	Electrical housing unit which balances and controls the energy used to power the top drive	--
	--	Shale Shakers	A series of vibrating screens used to remove the earth cuttings from the circulating fluids from the wellbore	--
	--	Substructure	The steel platform and supports on which the mast and all drilling floor equipment sit. Also provides space for well control equipment and storage by elevating drilling floor components.	--
	--	Top Drive	Power swivel which rotates the drillstring without a rotary table or Kelly hose	--
	--	Travelling Block	Pulleys or sheaves; used to raise or lower equipment into the well	--
Completion/Production	**--**	Perforating Gun	Tool to create perforations in the well casing.	--
	--	Ball/Packer or Plug	Type of packer using a steel ball to isolate downhole segments.	--
	--	Portable Water Tanks	Water storage.	Venting
	--	Sand Proppant tank	Proppant storage.	--
	--	Chemical Trucks	Chemical storage.	--
	--	Frac Fluid mixer (pipe manifold)	Mixes proppant with frac fluid prior to injection.	--
	--	Flowback lined pit/tank	Storage of produced fluid during flowback.	Venting
	--	Hydraulic pumper truck	Pump and pump driver for frac fluid.	Combustion

Use	Subtask Section #	Equipment	Description	Emissions Source for Typical U.S. Operations
	--	Cellar	A pit around the wellhead which provide space for the installation of equipment at the top of the wellborn such as the BOP Stack. Water and waste fluids also accumulate in the cellar for disposal.	--
	C10	Compressors	Raises the pressure of a compressible fluid such as air or gas. Compressors create a pressure differential to move or compress a vapor or a gas. Industry presentations and staff observations during May 2009 PA field visit indicated that centralized compressor stations are a more likely model for the production phase*.	Venting, Fugitives, VOC's, Methane
	C11	Glycol Dehydrator	Used to remove water from extracted gas to prevent liquid accumulation in pipelines	VOC's, Venting, Methane
All Phases	--	Doghouse	Small building on the rig floor used as driller's office. Serves as shelter for crew and storage for small tools and equipment. Sometimes used for mudlogging.	--
	C12	Engine/Generator Set	Fueled most commonly by diesel, the engine converts fuel combustion into motion. The motion is then converted to electric by the generator and used as a power source for various drillsite components (such as Quarters)	Combustion
	C13	Quarters	Trailers in which the offices of the company representatives, rig managers or rig superintendents, operators, crew members, and other parties reside	Combustion, Human Waste
	B1	Trucks	Trucks are used in hauling everything from cement, sand and water for hydraulic fracturing, chemicals, waste fluids for disposal, the drill rig, and other required equipment	Combustion, Particulate Matter
	C14	Water Tanks/Storage Tanks	Stores water that is needed for various functions on the drillsite, including: circulating, cementing, cooling, and cleaning. Storage tanks can be used to collect mud and cuttings from drilling instead of the lined pits. Portable tanks are used to collect many fluids, such as completion fluids, spent hydraulic fracturing fluids/chemicals, workover fluids, etc.	VOC's, fugitives, venting
	D15	Flares	Flaring is a high-temperature oxidation process used to burn combustible components, mostly hydrocarbons, of waste gases from industrial operations. Depending on flare ignition and operating factor, the flare stack may result in cold venting of the stream for periods of time.	Combustion, venting

Source(s):

Petrocasa Energy, Inc/Harding Energy Partners, LLC - 3-D Interactive Drilling Rig Presentation

http://www.petrocasa.com/3D%20Rig%20Animation%20Web%20Version/index.html

*Comments from DEC/NYSERDA - May 19, 2009

Emissions source information develop from ICF subject matter expertise

2.2.2 Onsite Truck Usage

1. Trucks: The biggest pollutant from motor vehicle traffic at natural gas drilling operations is particulate matter. Similar to generators and construction vehicles, burning fuel to power trucks emits NOx, CO, CO_2, and SO_2 as mobile source combustion, but this is outside the scope of the NYS Marcellus Shale study. As for the number of trucks used, the state of Montana has provided a general EIS for Coal Bed Methane (CBM) wells ("Montana CBM EIS"), and it states: "…3 crew pickup trucks, 1 well logging truck, 1 pipe truck, 2-4 water trucks, 1 cement truck…"[26] However, consultation with one industry operator already drilling in the Marcellus Shale suggests that truck traffic at a typical well site is much heavier. One rig drilling one horizontal well requires 25 trucks for hauling construction equipment, 4 trucks for location building equipment, 143 truck loads of sand and 158 truck loads hauling water for hydraulic fracturing. This amounts to 330 truck

[26] Final Statewide Oil and Gas EIS and Proposed Amendment of the Powder River and Billings RMP's (Montana CBM EIS) - http://www.deq.state.mt.us/CoalBedMethane/FinalEIS/Volume%20I/07%20Chapter-4.pdf

loads of traffic at a well site during construction through well completion[27]. The number of truck loads is dependent on truck size as allowed by local road weight restrictions.

2.2.3 Possible Emissions Sources For A Typical Well Pad

1. Construction Equipment: These vehicles generally run on diesel fuel, and combustion of this fuel will directly result in the emission of nitrogen oxides (NOx), carbon monoxide (CO), CO_2, and sulfur dioxide (SO_2) ("combustion emissions"). Most of these vehicles and equipment are for temporary use only.
2. Mud Return Line: Possible leaks in the pipe could result in the release of fugitive hydrocarbon or CO_2 emissions whose composition will depend on the formation gas composition.
3. Mud System: It can be a possible source of aforementioned emissions during separation and removal of cuttings.
4. Mud-Gas Separator: Safely vents large pockets of free or sour gas that may include toxic gases such as hydrogen sulfide (in addition to the small amounts of VOC's, methane, and CO_2). Some models can be skid-mounted and trailer transportable[28].
5. Mud Pit/Lined Pits: This is a source of emissions from drilling itself. Prior to disposal, these drilling wastes (muds and cements) are often stored in these lined pits that are open to the air, but are reclaimed shortly after drilling. In general for natural gas production, some of the more volatile compounds will escape from the produced water lined pits into the atmosphere. This is not a large issue for Marcellus Shale gas due to its composition—water degassing will not result in BTEX emissions based on field gas compositions. In addition, New York State prohibits the use of lined pits for the storage of produced water during natural gas production and produced brine must be stored in tanks.
6. Mud Pumps: Any venting or leaking of these pumps can result in emissions from drilling fluids.
7. Choke Manifold: These valves and pipes are all possible sources of fugitive emissions.
8. Accumulator: This could be a possible source of fugitive emissions, due to possible leaks of hydraulic fluid or compressed nitrogen.
9. BOP Stack: Venting in the event of a blowout is a large source of emissions, but such occurrences are rare. In the event that the BOP is activated, only the initial gas kick from the well is released because if the well killing operation is conducted correctly, the gas is shut off.
10. Compressors: Compressors can be seen as an emission source in two ways: 1) Through the combustion of diesel fuel or natural gas for the compressor driver, and; 2) through fugitive and vented emissions from the compressor. Like construction equipment, burning fuel to power these compressors emits combustion emissions. Methane emissions also occur as fugitive emissions from piping connectors and valves, and vented emissions from depressuring compressors when taken out of service. Compressors mainly leak methane which has been explored in detail. More than 51,000 reciprocating compressors are operating in the U.S. natural gas industry, each with an average of four cylinders, representing over 200,000 piston rod packing systems in service. These systems contribute over 72.4 Bcf per year of methane emissions to the atmosphere, one of the largest sources of emissions at natural gas compressor

[27] Jared Hall (East Resources Inc.) General Mgr. – Teleconference @ 2p.m. 4/13/09
[28] M-I SWACO: Land Mud-Gas Separator Features & Benefits - http://www.miswaco.com/Products_and_Services/Drilling_Solutions/Pressure_Control/Mud_Gas_Separators/Mud_Gas_SeparatorsDocuments/LAND%20MUD-GAS%20SEPARATOR.cfm

stations[29]. The amount of emissions for each well completion depends on the number, size, and type of compressors used on-site. Consultation with industry operators indicates that one large permanent compressor per site is generally the minimum required for a single or a multiple well site and typically requires 100 hp per 1 MMcf of gas compressed[30], though the design decisions may result in multiple compression solutions. Many scenarios for compression are possible, ranging from multiple smaller compressors servicing one well pad to a large centralized compressor servicing many well pads; based on the referenced discussions with operators, the anticipated design decision is centralized compression servicing multiple well pads. Compressor portability can depend on site sizes and distances between each well, but it is possible that an additional portable compressor may be on-site in the circumstances that compression is needed at the well itself.

11. Glycol Dehydrators: If the gas well uses glycol dehydrators to remove water from the gas, the dehydrator may release hydrocarbons, depending on the gas composition of the formation. If the natural gas undergoing dehydration contains pollutants, quantities can be released when the glycol solution undergoes regeneration. Consultation with industry operators indicates that one dehydration facility per site is generally the minimum required to prevent liquids accumulation in the pipelines[31]. Glycol dehydrators also vent methane to the atmosphere from the glycol regenerator and also bleed natural gas from pneumatic control devices[32].
12. Engine/Generator Set: Like construction equipment, the burning of diesel fuel to power this generator emits combustion emissions. Mainly used for drilling, but could power Quarters (see #35).
13. Quarters: Emissions result from the use of diesel fueled electric generators, where drill sites are not close to the commercial electric power. Burning fuel to power electrical generators emits combustion emissions.
14. Water Tank/Storage Tanks: While storage tanks used for fresh water are not considered a source for emissions, other types of storage tanks can be large emissions sources.
    a. When discussing storage tanks, the 1992 GEIS states:
        i. "The operator may elect to install one or more tanks at a well site to collect brine and/or oil. Since such tanks are usually associated with the production phase, they are one of the more permanent features of a well site. Brine from drilling operations usually goes to the mud or lined pit. However, the Department [New York State Department of Environmental Conservation] has the authority to require installation of tanks for handling drilling brines also. Tanks on well site locations generally range in size from 12 to 200 barrels (one oil field barrel = 42 gallons… Portable tanks, called Baker tanks, may also be installed at a well site to temporarily store such things as fresh water, completion fluids, workover fluids and flowback fluids. These square or rectangular tanks generally rest horizontally on a skid which allows them to be moved more easily. In fact, a single tank may be employed for a number of uses in different locations around the well site over a relatively short period of time. Tanks may also be rented from a supply company as needed. Under such conditions, they

[29] U.S. EPA – Natural Gas STAR Program – "Lessons Learned: Reducing Methane Emissions from Compressor Rod Packing Systems" – http://www.epa.gov/gasstar/documents/ll_rodpack.pdf
[30] Jared Hall (East Resources Inc.) General Mgr. – Teleconference @ 2p.m. 4/13/09
[31] Jared Hall (East Resources Inc.) General Mgr. – Teleconference @ 2p.m. 4/13/09
[32] U.S. EPA – Natural Gas STAR Program – "Lessons Learned: Replacing Glycol Dehydrators with Desiccant Dehydrators" – http://www.epa.gov/gasstar/documents/ll_desde.pdf

are rarely anchored in place like permanent brine and oil storage tanks." Portable tanks may range in size up to 500 barrels.

b. Emissions from condensate tanks can be quite significant when the gas composition necessitates their use, though this is not the case in NYS Marcellus Shale. Condensates are hydrocarbons that are in a gaseous state within the reservoir (prior to production), but become liquid during the production process. Condensates are composed of hydrocarbons (typically those heavier than methane), as well as aromatic hydrocarbons such as BTEX. The vapors of BTEX are heavier than air and may accumulate in low-lying areas.[33] A storage tank battery can vent 4,900 to 96,000 thousand cubic feet (Mcf) of natural gas and light hydrocarbon vapors to the atmosphere each year[34]. Later subtask sections will discuss this issue for Marcellus Shale production and show how NYS Marcellus Shale gas composition results in virtually no condensate.

2.2.4 Flare Characteristics

15. Flares: In general, operating flares emit the products of combustion. It is also common to flare natural gas that contains hydrogen sulfide in order to convert the highly toxic hydrogen sulfide gas into sulfur dioxide. Flares emit a host of air pollutants, depending on the chemical composition of the gas being burned and the efficiency and temperature of the flare. A major issue with production flaring is the flare operating factor. The flare can often go out due to low throughput or low heat content of the waste gas stream. Characterizing any non-ignited vent time of hydrocarbons is difficult, as well as characterizing flare waste gas throughputs which are both unsteady and are also typically not metered. A simplifying assumption to represent unsteady, unmetered flare rates is to take a worst case scenario based on the maximum expected well production rate. This maximum rate produced with a gathering line backpressure will serve as a surrogate for gas rate during flowback with minimal backpressure from the flare. The size of the flare is therefore represented as a maximum heat release rate of 10,763 MMBtu/day, based the average Marcellus Shale gas compositions provided in subtask 2.5 and a maximum rate of 10 MMcf/day. Later subtask sections will estimate volumes and potential emissions from flaring. Flaring may be a required when in the vicinity of population centers but also can raise issues of concern by local residents with its visible flame and potential noise.

[33] US EPA - Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources – Chapter 13: Miscellaneous Sources - www.epa.gov/ttnchie1/ap42/ch13/final/c13s05.pdf
[34] U.S. EPA – Natural Gas STAR Program – "Lessons Learned: Vapor Recovery Tower/VRU Configuration" – http://www.epa.gov/gasstar/documents/vrt_vru_configuration_08_21_07.pdf

SUBTASK 2.3: IDENTIFICATION OF POLLUTANTS, EMISSION FACTORS, AND STACK PARAMETERS

The previous section reviewed the possible sources of emissions and pollutants in the equipment used during a typical gas extraction. This section reviews the pollutants themselves. Discussion on criteria pollutants and their precursors which can be emitted from all equipment used will be included.

2.3.1 Criteria Pollutants and Emissions

Here is a look at the list of all possible emissions and pollutants during all phases of a typical gas extraction in the Marcellus Shale.

1. Particulate Matter (PM): The most common sources of particulate matter from natural gas operations are dust or soil entering the air during pad construction or from traffic on access roads, and diesel exhaust from vehicles and engines used to power machinery at natural gas facilities. Particulate matter can also be emitted during venting and flaring operations.
2. Sulfur Dioxide: SO_2 is formed during the combustion of fossil fuels that contain sulfur, such as diesel or raw natural gas. Flares and machinery that run on diesel and natural gas emit sulfur dioxide at natural gas drilling operations.
3. Nitrogen oxides: NOx is a term for various highly reactive compounds that contain nitrogen and oxygen. NOx is emitted from the combustion of fossil fuels, especially at very high temperatures. Vehicles and power plants are the principal emitters of NOx. NOx is also emitted at natural gas operations from flaring, and is part of exhaust from diesel and natural gas engines that power machinery such as compressor engines and other heavy equipment.
4. Carbon monoxide: Carbon monoxide is emitted during flaring, and from the operation of machinery at natural gas development sites.
5. Volatile organic compounds (VOC's): VOC's include a host of chemicals that contain carbon and evaporate easily at room temperature[35]. VOC emissions depend to a significant degree on the gas composition and are not a large fraction of NYS Marcellus Shale gas.
   In general for natural gas operations, BTEX can be emitted during various natural gas operation activities, including flaring, venting, operating machinery such as generators and compressors, and can emanate from produced water storage tanks and be released during the dehydration of natural gas. In 2007, EPA implemented a new standard referred to as the Maximum Achievable Control Technology (MACT) standard for hazardous air pollutants (HAP's) such as BTEX that targeted small area sources such as shale gas operations located in areas near larger populations. These standards limit HAP emissions (primarily benzene) from process vents on glycol dehydration units, storage vessels with flash emissions, and equipment leaks[36].
6. Methane: Natural gas, primarily the greenhouse gas methane, is released during venting operations, or when there are leaks in equipment used during natural gas development. Venting occurs at a number of points during gas development

[35] U.S. Environmental Protection Agency. http://iaq.custhelp.com/cgi-bin/iaq.cfg/php/enduser/std_adp.php?p_faqid=3218
[36] U.S. Department of Energy (DOE) – Office of Fossil Energy – "Modern Shale Gas Development in the United States: A Primer" – www.gwpc.org/e-library/documents/general/Shale%20Gas%20Primer%202009.pdf

process, such as well completion, and well/pipeline/tank maintenance. Sources include (but are not limited to) compressors, the BOP stack, and flares. The primary component of natural gas is methane. In addition to methane, natural gas typically contains other hydrocarbons such as ethane, propane, butane, and pentanes. In general, raw natural gas may also contain hazardous air pollutants such as BTEX, hydrogen sulfide, and CO_2, though later sections discuss applicability for NYS Marcellus Shale specifically

2.3.2 Fuels Used

Information regarding fuels used during all phases of a typical gas extraction in the Marcellus Shale can be found in Sections 2.4 through 2.6.

2.3.3 Percent Sulfur Content and Emission Factors

Information regarding the percent sulfur content of equipment emissions, as well as their emission factors, can be found in Section 2.6. Information on emission factors of specific equipment will be covered in Table 2.6.1.

2.3.4 Truck Emission Factors

Truck emission factors for mobile source emissions were to be not necessary for the NYS DEC modeling effort.

2.3.5 Greenhouse Gas Emissions

Greenhouse gas emissions are typically categorized into vented emissions, combustion emissions, and fugitive emissions. Fugitive emissions, defined as unintentional gas leaks to the atmosphere, pose several challenges for quantification since they are unintended, typically invisible odorless and not audible, and often go unnoticed. Examples of fugitive emissions include leaks from flanges, tube fittings, valve stem packing, open-ended lines, compressor seals, and pressure relief valve seats. Three typical ways to quantify fugitive emissions at a natural gas industry site are 1) facility level emission factors, 2) component level emission factors paired with component counts, and 3) measurement studies. Facility level emission factors are not recommended for modeling purposes and are more appropriate for a scoping study of emissions rates. Facility level factors, typically developed from averages across U.S. sites, are average numbers incorporating site that may, for example, have dozens of wells and site that may have one well. A more appropriate way to quantify fugitive greenhouse gas emissions for this effort is component level factors, can quantify emissions at a Marcellus Shale site with more confidence. The API Compendium[37] provides guidance on component level factors. Emission rates should be adjusted to account for both the methane content and carbon dioxide content in streams at the specific location, i.e. using Marcellus Shale stream compositions provided in subtask 2.5. Measurement studies provide the most accurate quantification of fugitive emissions at a specific facility for a given time but require more resources than an emission factor estimate and require that the facility already be in existence.

[37] American Petroleum Institute. *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*. February, 2004. Page 6-9.

Additional information regarding specific greenhouse gas emissions can be found in Section 2.6.

SUBTASK 2.4: ESTIMATE OF INDIRECT AIR EMISSIONS FROM HYDRAULIC FRACTURING

This section will examine indirect air emissions that would occur in a typical hydraulic fracturing process. This involves an examination of water handling at the site, the likelihood of air emissions due to water misting or sprays when deposited in a holding pond, and the additives which might be released from the water to the atmosphere.

For this report, indirect air emissions refer to possible evaporation emissions from hydraulic fracturing fluid sitting in a waste pond. Note that other conventions for the use of indirect air emissions from oil and natural gas operations are classified as emissions from purchased electricity for site use[38].

2.4.1 Hydraulic Fracturing Water Handling at Site

Given that NYS Marcellus Shale is in the early stages of development, common practices for water handling have not been developed, but a worst case scenario can be developed from available information and surveys of what NYS Marcellus Shale operators plan to implement.

One operator reports that water used for hydraulic fracturing of wells in the NYS Marcellus Shale is usually trucked on site[39]. It is estimated that over 19,000 barrels (bbl) of water are needed per hydraulic fracturing procedure[40]. Because of the long length of each horizontal well, several fracturing stages are required per well. As stated in Subtask 2.1, Section F, an entire hydraulic fracturing job may use between 50,000 to 80,000 bbl of water[41]. In general, water can be stored in tanks, a lined pit, or centralized impoundments servicing multiple pads. Water can be stored in large, portable water tanks at the well site, similar to the tanks shown in Exhibit 2.4.1, and then pumped from the water tanks down-hole, with one Marcellus Shale operator reporting using frac tanks to capture the frac fluid and produced water from the well[42]. A lined pit is also an option for capturing flowback fluid, and operators report plans to construct lined pits at the wellsite for temporary storage of flowback fluids. East Resources reports that lined pits to be located on a NYS Marcellus Shale wellsite will be sized to hold up to 17,860 bbls, receive fluids from flowlines, and will be segmented to allow for separation of flowback. These lined pits are for temporary storage and treatment of flowback fluids until the fluids are used for later fracturing jobs. The lined pits remain in use for over a month after a frac job.

Although this report focuses on wellsite emissions, observations during recent field trips indicate that fluid from multiple well sites may be accumulated at a centralized impoundment for flowback fluid. NYS Marcellus Shale operator Fortuna reports in its response to a June 19, 2009 information request that their future centralized impoundments are not expected to exceed dimensions of 150 feet by 250 feet in area and 12 feet in depth, containing approximately 28,570 bbls. Fluids transport from a

[38] *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*. API. pg. 1-5. api.org/ehs/climate/new/upload/2004_COMPENDIUM.pdf.
[39] Jared Hall (East Resources Inc.) General Mgr. – Teleconference @ 2p.m. 4/13/09
[40] Jared Hall (East Resources Inc.) General Mgr. – Teleconference @ 2p.m. 4/13/09
[41] Argonne National Laboratory: EVS – Trip Report for Field Visit to Fayetteville Shale Gas Wells. http://www.evs.anl.gov/pub/doc/ANL-EVS_R07-4TripReport.pdf
[42] Jared Hall (East Resources Inc.) General Mgr. – Teleconference @ 2p.m. 4/13/09

central location would occur either via a flowline or truck, and the central location would service a radius of 2 to 4 miles. Fortuna reports that a centralized impoundment may exist for the duration of the development period, up to three years. For purposes of assessing worst-case impacts specifically at a wellsite, a conservative assumption is to assume each wellsite has a lined pit receiving fluids.

Exhibit 2.4.1: Example of Water/Frac Fluid Tanks on Site as One Method for Fluids Handling[41]

2.4.2 Hydraulic Fracturing Water Handling at Site

Based on experience with gas well completions, the likelihood of emissions due to spraying or misting as the fluid is routed to a lined holding pond (or tank) is negligible. For lined pits, it is not common practice to operate during weather conditions responsible for significant mists or sprays since these conditions would also prevent fracture, flowback, or other work. Fortuna has reported that fluids will be moved using a "zero spill approach" where no unintentional fluid releases to the environment are expected to occur, and that it does not see a danger of spraying or of off-gassing from water handling.

2.4.3 Possible Release of Additives to Atmosphere

Fracturing fluid currently being utilized in the Marcellus Shale is comprised of mainly of sand, water and polymers. When the fluid is flowed back out of the well, it is typically stored in tanks or lined pits until it can be trucked to a waste water treatment facility or other disposal facility; storage in tanks minimizes atmospheric contamination from the additives in the flow- back. However, the lack of infrastructure in the NYS Marcellus Shale area to dispose of waste water and completions fluids may prove to be one of the greatest obstacles in the development of this play[45].

NYS DEC has received proprietary information concerning in the composition of frac fluid used in the Marcellus Shale. This information is presented below[43], in generic

[43] Personal correspondence with New York State Department of Environmental Conservation, April 10, 2009.

form and is discussed in much greater detail in Task 1. The information in Exhibit 2.4.2 is for a frac fluid being used in a vertical well in the NYS Marcellus Shale, and the same information on composition also applies to frac fluids for horizontal wells. The volumes used in horizontal wells will increase, but as previously stated the composition of the fluid will remain the same. Contributions of frac fluids to air emissions is expected to be negligible due to the extremely low concentrations of materials of concern in the fluids themselves. It is suggested however, that frac fluids compositions be monitored given the wide variety of compounds in use today and the continual development of new formulations may change this assessment.

Exhibit 2.4.2: Composition of Frac Fluid Used in Marcellus Shale[43]

Additive	Volume	Percentage of Total Fluid Volume
Water	57,143 bbl	99.375%
Friction Reducer (Polymer)	71.5 bbl*	0.500%
Biocide (Polymer)	3.6 bbl*	0.025%
Friction Reducer (Alcohol)	14.3 bbl*	0.100%

More specific information on additives has been presented in Task 1.

In addition, NYS Marcellus Shale operator Fortuna reports in its response to a June 19, 2009 information request the following on flowback fluid:
"As the fluid will average approximately 15,000 ppm to 30,000 ppm TDS and should have no volatiles in it we do not see how air emissions is a problem. We will transfer our flowback fluids by truck or pipeline with a zero spillage approach. No off gassing effects are expected and so no special mitigation measures should be needed."

SUBTASK 2.5: ESTIMATE OF EMISSIONS ASSOCIATED WITH EXTRACTED GAS

This section will look more closely at emissions that may occur from the extracted natural gas itself. Emissions will be differentiated by type and quantified. Where emissions are not expected, an explanation will be provided. Also, the subtask will conclude how much dehydration is required for gas specific to the Marcellus Shale.

2.5.1 Amount of Potential Gas Releases Without Capture

This section reviews the available public information on potential gas releases and develops a worst cast scenario from that body of data. Well production rates are important to characterize since initial rates can be surrogates for completion flaring rates. Below is a compilation of gas releases and durations from different references to illustrate the range of possibilities.

- For the U.S. overall, the hydraulic facture phase of well development is reported to last on the order of days (rather than weeks, months, or years)[44].
- During Marcellus shale well completion, flaring of natural gas produced will typically last between four to 15 days, with between 1 to 8 MMcf per day (MMcfd) of produced natural gas combusted in the flare[40].
- Information gathered by NYSERDA and NYS DEC field trips to Marcellus Shale well sites indicate a potential production rate of 7 to 10 MMcf per day.
- Information reported by Marcellus Shale operator Fortuna is an initial production rate of 2.8 MMcf per day declining to 0.9 MMcf per day in the first year and declining further over the life of the well. Fortuna reports that it is expecting short-term flaring durations of 6 to 10 hours as a well transitions from water to gas, totaling 300 to 500 Mcf of gas flared—this assumes that pipelines will be able to be built before well completion so that much of the flowback gas can go to sales instead of the flare.

Exhibit 2.5.1 shows shale gas composition in general. The first part of the table is not representative of NYS Marcellus Shale and points to the need for Marcellus Shale gas compositions specifically. The second part of the table shows NYS Marcellus Shale gas compositions provided to NYS DEC by operator Chesapeake. Natural gas extracted from the Marcellus Shale is comprised of mainly methane (C_1), ethane (C_2), propane (C_3), carbon dioxide (CO_2) and nitrogen (N_2)[45].

---

[44] Modern Shale Gas Development in the United States: A Primer. http://www.all-llc.com/pdf/ShaleGasPrimer2009.pdf

[45] Bullin, Keith, et al. "Compositional Variety Complicates Processing Plans for US Shale Gas." Oil and Gas Journal. Vol 107, Issue 10. 9 March 2009. ogj.com/articles/article_display.cfm?ARTICLE_ID=355486&p=7&section=ARCHI&subsection=none&c=none&page=1&x=y&x=y&x=y

Exhibit 2.5.1: Sample Gas Composition[46]

Shale Gas Compositions					
Well Number	Methane	Ethane	Propane	Carbon Dioxide	Nitrogen
11	79.4	16.1	4.0	0.1	0.4
2	82.1	14.0	3.5	0.1	0.3
3	83.8	12.0	3.0	0.9	0.3
4	95.5	3.0	1.0	0.3	0.2

Mole percent samples from Bradford Co., PA[47]											
Sample Number	Nitrogen	Carbon Dioxide	Methane	Ethane	Propane	i-Butane	n-Butane	i-Pentane	n-Pentane	Hexanes +	Oxygen	sum
1	0.297	0.063	96.977	2.546	0.107		0.01					100
2	0.6	0.001	96.884	2.399	0.097	0.004	0.008	0.003	0.004			100
3	0.405	0.085	96.943	2.449	0.106	0.003	0.009					100
4	0.368	0.046	96.942	2.522	0.111	0.002	0.009					100
5	0.356	0.067	96.959	2.496	0.108	0.004	0.01					100
6	1.5366	0.1536	97.6134	0.612	0.0469					0.0375		100
7	2.5178	0.218	96.8193	0.4097	0.0352							100
8	1.2533	0.1498	97.7513	0.7956	0.0195		0.0011			0.0294		100
9	0.2632	0.0299	98.0834	1.5883	0.0269	0.0000	0.0000	0.0000	0.0000	0.0000	0.0083	100
10	0.4996	0.0551	96.9444	2.3334	0.0780	0.0157	0.0167	0.0000	0.0000	0.0000	0.0571	100
11	0.1910	0.0597	97.4895	2.1574	0.0690	0.0208	0.0126	0.0000	0.0000	0.0000	0.0000	100
12	0.2278	0.0233	97.3201	2.3448	0.0731	0.0000	0.0032	0.0000	0.0000	0.0000	0.0077	100

For the Bradford County, PA gas analyses, sample number 1 included a sulfur analyses and found less than 0.032 grams sulfur per 100 cubic feet. The other samples did not include a sulfur analysis. Samples 1, 3, 4 had no detectable hydrocarbons greater than n-butane. Sample 2 had no detectable hydrocarbons greater than n-pentane. Based on the low VOC content of these compositions, pollutants such as BTEX are also not expected based on the following information from Marcellus Shale operators:

- Marcellus Shale operator East Resources reports that it has not tested for benzene, xylene, or hydrogen sulfide and do not expect them to be present in measurable quantities given the reservoir type.
- Marcellus Shale operator Fortuna has sampled for benzene, toluene, and xylene and did not detect it in its gas samples or water analysis.

Fortuna also reports testing for hydrogen sulfide regularly with readings of 2 to 4 parts per million during a brief period in vertical wells, and its presence has not reoccurred since.

When estimating emissions from flaring, it is industry practice to assume a worst case 98% combustion efficiency of the flare, leaving 2% uncombusted gas emitted [48]. Emissions from flaring in the Marcellus Shale are estimated below. The rates estimated

[46] "Compositional variety complicates processing plans for US shale gas" *Oil and Gas Journal*. Vol 107, Issue 10. 9 Mar 2009.
[47] Personal Contact, Kathleen Sanford, NYS DEC, 6/15/2009
[48] *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*. API. pg. 4-29. api.org/ehs/climate/new/upload/2004_COMPENDIUM.pdf.

below are also appropriate as worst-case emissions from natural gas fired burners found in line heaters.

From interviews with industry operators[40], certain assumptions can be made about flaring procedures in the Marcellus Shale. First, it is assumed that the flare gas composition is similar to the field gas composition presented in Exhibit 2.5.1 above which Chesapeake has supplied from its Marcellus Shale operations. In Exhibits 2.5.2 to 2.5.12, the average gas composition from Exhibit 2.5.1 is used. For SO_2 emissions, the reported worst case of 0.32 grams per 100 cubic feet, equating to about 7.9 parts per million, from above is used. Second, it is assumed that during well completion operations, an average of 10 MMcf of produced gas per day is flared (based on the upper range of expected production rate, which is used as a surrogate for well flow rate during completion), for an assumed 7 days. Using these assumptions, GHG emissions from the flare can be calculated as illustrated below. Third, in some instances emissions cannot be derived from gas compositions alone (PM, NO_x, CO), in which case industry standard AP-42 factors are used. Fourth, the gas compositions show an absence of HAPs and BTEX, and as stated above one operator tested for BTEX and did not find any in the gas; therefore, based on the available information, HAP and BTEX are estimated as zero. A table accompanying this report provides worst case emission factors and activity factors for modeling.

Exhibit 2.5.2: Methane Emissions from Flaring

$$\frac{10.0\,\text{x}\,10^6\ \text{scf}}{\text{day}}\ \text{x}\ \frac{\text{lbmole}}{379.3\text{scf gas}}\ \text{x}\ \frac{0.972\ \text{lbmole}\ CH_4}{\text{lbmole gas}}\ \text{x}\ \frac{16.04\ \text{lb}\ CH_4}{\text{lbmole}\ CH_4}\ \text{x}\ \frac{0.02\ \text{lb noncombusted}\ CH_4}{\text{lb}\ CH_4}\ \text{x}\ \frac{1\text{short ton}}{2{,}000\ \text{lbs}} = 4.1\ \text{tons}CH4/\text{day}$$

key assumptions: 2 % by volume uncombusted; take average Marcellus gas composition

Exhibit 2.5.3: Carbon Dioxide Emissions from Flaring

$$\frac{10.0\,\text{x}\,10^6\ \text{scf}}{\text{day}}\ \text{x}\ \frac{\text{lbmole gas}}{379.3\text{scf gas}}\ \text{x}\left(\frac{0.972\ \text{lbmole}CH_4}{\text{lbmole gas}}\ \text{x}\ \frac{1\text{lbmole}C}{\text{lbmole}CH_4} + \frac{0.019\ \text{lbmole}C_2H_6}{\text{lbmole gas}}\ \text{x}\ \frac{2\ \text{lbmole}C}{\text{lbmole}C_2H_6} + \frac{0.001\text{lbmole}C_3H_8}{\text{lbmole gas}}\ \text{x}\ \frac{3\text{lbmole}C}{\text{lbmole}C_3H_8}\right)\text{x}$$

$$\frac{0.98\ \text{lbmole formed}}{\text{lbmole}C\ \text{sent to flare}}\ \text{x}\ \frac{44\ \text{lbs}CO_2}{\text{lbmol}CO_2}\ \text{x}\ \frac{1\text{short ton}}{2{,}000\ \text{lbs}} = 576\ \text{tons}CO_2/\text{day}$$

key assumptions: 2% by volume uncombusted; take average Marcellus gas composition

Exhibit 2.5.4: Nitrous Oxide Emissions from Flaring[49]

$$\frac{10.0\ \text{MMcf}}{\text{day}}\ \text{x}\ \frac{5.9\text{x}10^{-7}\ \text{tonnes}\ N_2O}{\text{MMcf gas}}\ \text{x}\ \frac{1.102\ \text{tons}\ N_2O}{1\text{tonne}\ N_2O} = 6.5\ \text{x}\ 10^{-6}\ \text{tons}N_2O/\text{day}$$

key assumptions: use API Compendium N_2O emission factor

Exhibit 2.5.5: PM Emissions from Flaring

$$\frac{10.0\ \text{MMcf}}{\text{day}}\ \text{x}\ \frac{7.6\ \text{lbPM}}{\text{MMcf}}\ \text{x}\ \frac{\text{ton}}{2{,}000\text{lb}} = 0.38\ \text{tons}PM/\text{day}$$

key assumptions: use worst case PM factor from EPA AP-42 natural gas combustion[50]

[49] N_2O emissions are based on natural gas production rate, not the gas throughput to the flare. It is assumed that average initial production rate is 10.0 MMcf, as stated in reference 55. The predetermined API Emission Factor for N_2O can be found in the API Compendium, Table 4-7, page 4-30. api.org/ehs/climate/new/upload/2004_COMPENDIUM.pdf.

Exhibit 2.5.6: NO_x Emissions from Flaring

$$\frac{10.0\ \text{MMcf}}{\text{day}} \text{ x } \frac{1076\ \text{MMBTU}}{\text{MMcf}} \text{ x } \frac{0.068\text{lb } NO_x}{\text{MMBTU}} \text{ x } \frac{\text{ton}}{2{,}000\text{lb}} = 0.4 \text{ tons CO/day}$$

key assumptions: use worst case CO factor from EPA AP-42 flaring

Exhibit 2.5.7: CO Emissions from Flaring

$$\frac{10.0\ \text{MMcf}}{\text{day}} \text{ x } \frac{1076\ \text{MMBTU}}{\text{MMcf}} \text{ x } \frac{0.37\text{lb CO}}{\text{MMBTU}} \text{ x } \frac{\text{ton}}{2{,}000\text{lb}} = 2 \text{ tons CO/day}$$

key assumptions: use worst case CO factor from EPA AP-42 flaring[51]

Exhibit 2.5.8: VOC Emissions from Flaring

$$\frac{10.0 \text{x} 10^6 \text{ scf}}{\text{day}} \text{ x } \frac{0.02 \text{scf gas uncombusted}}{1.0 \text{ scf gas combusted}} \text{ x } \frac{\text{lbmole}}{379.3 \text{scf gas}} \text{ x } \frac{0.01988 \text{ lbmole VOC}}{\text{lbmole gas}} \text{ x } \frac{31.73 \text{ lb VOC}}{\text{lbmole}} \text{ x } \frac{1 \text{short ton}}{2{,}000 \text{ lbs}} = 0.1663 \text{tons VOC/day}$$

key assumptions: 2 % by volume uncombusted; take average Marcellus gas composition

Exhibit 2.5.9: HAP Emissions from Flaring

None

key assumptions: take average Marcellus gas composition (in this case each sample shows zero HAP)

Exhibit 2.5.10: BTEX Emissions from Flaring

None

key assumptions: take average Marcellus gas composition (in this case each sample shows zero BTEX)

Exhibit 2.5.11: H_2S Emissions from Flaring

$$\frac{10.0 \text{x} 10^6 \text{ scfgas}}{\text{day}} \text{ x } \frac{0.02 \text{scf gas uncombusted}}{1.0 \text{ scf gas combusted}} \text{ x } \frac{\text{lbmole gas}}{379.3 \text{scf gas}} \text{ x } \frac{7.9\text{E}-6 \text{ lbmole H2S}}{\text{lbmole gas}} \text{ x } \frac{34 \text{lb}}{\text{lbmole}} \text{ x } \frac{1 \text{short ton}}{2{,}000 \text{ lbs}} = 7.08 \text{x} 10^{-5} \text{ tons H2S/day}$$

key assumptions: 2 % by volume uncombusted; take worst case reported value of H2S

Exhibit 2.5.12: SO_2 Emissions from Flaring

$$\frac{10.0 \text{x} 10^6 \text{ scfgas}}{\text{day}} \text{ x } \frac{0.98 \text{scf gas uncombusted}}{1.0 \text{ scf gas combusted}} \text{ x } \frac{\text{lbmole gas}}{379.3 \text{scf gas}} \text{ x } \frac{7.9\text{E}-6 \text{ lbmole SO2}}{\text{lbmole gas}} \text{ x } \frac{64 \text{lb}}{\text{lbmole}} \text{ x } \frac{1 \text{short ton}}{2{,}000 \text{ lbs}} = 0.0065 \text{ tons SO2/day}$$

key assumptions: 2 % by volume uncombusted; take worst case reported value of H2S

[50] EPA AP-42. Table 1.4-2 www.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf take highest PM value as conservatively high estimate. Use this value instead of industrial flare value in given in table 13.5-1 since this value in Table 1.4-2 better matches NYS Marcellus Shale natural gas composition.

[51] EPA AP-42. Table 13.5-1. http://www.epa.gov/ttn/chief/ap42/ch13/final/c13s05.pdf

Vented emissions rates on a per day basis are also provided below as a worst case emissions scenario, using the same assumptions as above except rates are vented rather than combusted.

Exhibit 2.5.13: Methane Emissions from Venting

$$\frac{10.0 \times 10^6 \text{ scf}}{\text{day}} \text{ x } \frac{\text{lbmole}}{379.3 \text{scf gas}} \text{ x } \frac{0.972 \text{ lbmole } CH_4}{\text{lbmole gas}} \text{ x } \frac{16.04 \text{ lb } CH_4}{\text{lbmole } CH_4} \text{ x } \frac{1 \text{short ton}}{2{,}000 \text{ lbs}} = 205.5 \text{ tons} CH4/\text{day}$$

key assumptions: take average Marcellus gas composition

Exhibit 2.5.14: Carbon Dioxide Emissions from Venting

$$\frac{10.0 \times 10^6 \text{ scf}}{\text{day}} \text{ x } \frac{\text{lbmole}}{379.3 \text{scf gas}} \text{ x } \frac{0.0079 \text{ lbmole } CO2}{\text{lbmole gas}} \text{ x } \frac{44 \text{ lb } CO2}{\text{lbmole } CO2} \text{ x } \frac{1 \text{short ton}}{2{,}000 \text{ lbs}} = 0.458 \text{ tons} CO2/\text{day}$$

key assumptions: take average Marcellus gas composition for CO2 content in the gas samples

Exhibit 2.5.15: Nitrous Oxide Emissions from Venting

None

key assumptions: NO_x is a product of combustion

Exhibit 2.5.16: PM Emissions from Venting

None

key assumptions: PM is a product of combustion

Exhibit 2.5.17: NO_x Emissions from Venting

None

key assumptions: PM is a product of combustion

Exhibit 2.5.18: CO Emissions from Venting

None

key assumptions: CO is a product of combustion

Exhibit 2.5.19: VOC Emissions from Venting

$$\frac{10.0 \times 10^6 \text{ scf}}{\text{day}} \text{ x } \frac{\text{lbmole}}{379.3 \text{scf gas}} \text{ x } \frac{0.01988 \text{ lbmole VOC}}{\text{lbmole gas}} \text{ x } \frac{31.73 \text{ lb VOC}}{\text{lbmole}} \text{ x } \frac{1 \text{short ton}}{2{,}000 \text{ lbs}} = 8.32 \text{ tons} VOC/\text{day}$$

key assumptions: take average Marcellus gas composition

Below are additional calculations of specific VOCs

$$\frac{10.0 \times 10^6 \text{ scf}}{\text{day}} \text{ x } \frac{\text{lbmole}}{379.3 \text{scf gas}} \text{ x } \frac{0.00073 \text{ lbmole propane}}{\text{lbmole gas}} \text{ x } \frac{44.13 \text{ lb propane}}{\text{lbmole}} \text{ x } \frac{1 \text{short ton}}{2{,}000 \text{ lbs}} = 0.43 \text{ tons propane}/\text{day}$$

$$\frac{10.0 \times 10^6 \text{ scf}}{\text{day}} \text{ x } \frac{\text{lbmole}}{379.3 \text{scf gas}} \text{ x } \frac{0.00014 \text{ lbmole butane}}{\text{lbmole gas}} \text{ x } \frac{58.1 \text{ lb butane}}{\text{lbmole}} \text{ x } \frac{1 \text{short ton}}{2{,}000 \text{ lbs}} = 0.11 \text{ tons butane}/\text{day}$$

$$\frac{10.0 \times 10^6 \text{ scf}}{\text{day}} \text{ x } \frac{\text{lbmole}}{379.3 \text{scf gas}} \text{ x } \frac{0.00014 \text{ lbmole pentane}}{\text{lbmole gas}} \text{ x } \frac{72.2 \text{ lb pentane}}{\text{lbmole}} \text{ x } \frac{1 \text{short ton}}{2{,}000 \text{ lbs}} = 0.01 \text{ tons pentane}/\text{day}$$

$$\frac{10.0\,x\,10^{6}\ \text{scf}}{\text{day}}\ x\ \frac{\text{lbmole}}{379.3\text{scf gas}}\ x\ \frac{0.00015\ \text{lbmole hexanes}+}{\text{lbmole gas}}\ x\ \frac{86.2\ \text{lb hexanes}+}{\text{lbmole}}\ x\ \frac{1\text{short ton}}{2{,}000\,\text{lbs}}=0.13\ \text{tons hexanes}+/\text{day}$$

Exhibit 2.5.20: HAP Emissions from Venting
None.
key assumptions: take average Marcellus gas composition (in this case each sample shows zero HAP)

Exhibit 2.5.21: BTEX Emissions from Venting
None
key assumptions: take average Marcellus gas composition (in this case each sample shows zero BTEX)

Exhibit 2.5.22: H_2S Emissions from Venting

$$\frac{10.0\,x\,10^{6}\ \text{scfgas}}{\text{day}}\ x\ \frac{\text{lbmole gas}}{379.3\text{scf gas}}\ x\ \frac{7.9\text{E}-6\ \text{lbmole H2S}}{\text{lbmole gas}}\ x\ \frac{34\,\text{lb}}{\text{lbmole}}\ x\ \frac{1\text{short ton}}{2{,}000\,\text{lbs}}=0.0035\,\text{tons H2S}/\text{day}$$

key assumptions: take worst case reported value of H2S

Exhibit 2.5.12: SO_2 Emissions from Venting
None
key assumptions: SO2 is a product of combustion

2.5.2 Toxics/Hazardous Pollutants/VOCs

Emissions of air toxics, i.e. hazardous air pollutants (HAPs) and volatile organic compounds (VOCs) will occur from combustion sources onsite, including compressor engines. Emissions estimates of HAPs and VOCs are discussed in Section 2.6. It is appropriate to use EPA AP-42 guidance on emissions estimates, assuming as a worst case scenario that all diesel equipment is used. A more conservative scenario is that portable equipment will use diesel, and all fixed equipment such as compressors will be natural gas fired. Another scenario is that diesel will be used for the first well until a gas line is in place, at which time some equipment can transition to natural gas as fuel—though for conservativeness all diesel can be assumed.

Air toxics and HAPs within the gas stream itself are expected to zero since the gas analyses above show the constituents of the produced gas stream.

2.5.3 Dehydration

It is typical to operate one dehydrator per well pad[52]. VOC emissions from glycol dehydration can be calculated using the Gas Technology Institute (GTI) software named GRI-GLYCalc; this is the software used by the Wyoming DEQ and stipulated in EPA AP-42. It can be purchased from GTI for $140.00[53]. GLYCalc requires gas flow rate and

[52] Jared Hall (East Resources Inc.) General Mgr. – Teleconference @ 2p.m. 4/13/09
[53] Gas Technology Institute. gastechnology.org/webroot/app/xn/xd.aspx?it=enweb&xd=10abstractpage\12352.xml).

compositions and is associated more with providing emissions rates during normal operations than for projections. Alternatives include API Compendium guidance which supplies emission factors for methane.

SUBTASK 2.6: ESTIMATE OF EMISSIONS RATES

2.6.1 Equipment Emission Rates

i. Greenhouse Gas Emission Rates

Below, Exhibit 2.6.1 shows greenhouse gas (GHG) emission rates for associated equipment used during natural gas well completion and operation. The emission factors are listed in units of pounds emitted per hour, per piece of equipment. The activity factor is multiplied by the emission factor to arrive at the total emissions for a particular source with the worst case scenario shown in Exhibit 2.6.1

Assumptions for worst-case well pad emissions scenario

- 7 day flowback with 10MMcf/day gas flared
- 10 MMcf/day production per well
- 8 wells per pad
- well pad compression
- well pad dehydration

Also listed are the expected worst case activity factors at a well pad. Activity factors were developed assuming a maximum of 10 MMcf/day production rate per well, 8 wells per pad, well pad compression, and well pad dehydration. Centralization of any operations such as compression would reduce well pad emissions. Implementation of reduced emission completions would also reduce emissions, specifically from flaring during flowback. Equipment centralization may see some efficiency gains in compression or dehydration; the scenario depicted below on the requested basis of a well pad is therefore a worst case.

The activity factors (AFs) in Exhibit 2.6.1 are based on the assumptions for a worst case scenario of air emissions at a well pad. A total of four pneumatic devices associated with the glycol dehydrator were assumed as a worst case, though these could be absent if the well pad being modeled is electrified. Zero well blowdowns for liquids unloading (clean ups) were assumed given that the play is not expected to produce appreciable volumes of water after wells are completed (i.e. during normal operations after flowback has been completed). Four vessels were assumed for the vessel blowdown category—separator, glycol contactor, glycol flash tank, and glycol reboiler. 12 pressure relief valves were assumed, one per well plus one per vessel.

No restrictions on daily operating hours were found.

Exhibit 2.6.1: Emission Rate Information for Well Pad[54]

Emission Source/ Equipment Type	CH_4 EFs	CO_2 EF	Units[55]	EF Reference	AF
Fugitive Emissions					
Gas Wells					
Gas Wells	0.014	0.00015	lbs/hr per well	Vol 8, page no. 34, table 4-5	8
Field Separation Equipment					
Heaters	0.027	0.001	lbs/hr per heater	Vol 8, page no. 34, table 4-5	1
Separators	0.002	0.00006	lbs/hr per separator	Vol 8, page no. 34, table 4-5	1
Dehydrators	0.042	0.001	lbs/hr per dehydrator	Vol 8, page no. 34, table 4-5	1
Meters/Piping	0.017	0.001	lbs/hr per meter	Vol 8, page no. 34, table 4-5	8
Gathering Compressors					
Large Reciprocating Comp.	29.252	1.037	lbs/hr per compressor	GRI - 96 - Methane Emissions from the Natural Gas Industry, Final Report	1
Vented and Combusted Emissions					
Drilling and Well Completion					
Combustion emissions from Well Drilling; rig power	117.418	4.162	lbs/well	Global Emissions of Methane Sources by Radian for API (1992)	8
Normal Operations					
Pneumatic Device Vents	0.664	0.024	lbs/hr per device	Vol 12, page no. 48, table 4-6	4
Chemical Injection Pumps	0.477	0.017	lbs/hr per pump	Vol 13, page no. 27	8
Kimray Pumps	45.804	1.623	lbs/MMscf throughput	GRI June Final Report	1
Dehydrator Vents	12.725	0.451	lbs/MMscf throughput	Vol 14, page no. 27	1
Compressor Exhaust Vented					
Gas Engines	0.011			Vol 11, page no. 11	1
Well Workovers					
Gas Wells	0.013	0.00046	lbs/hr per well workover	Vol 6, page no. 18, table 4-2	8

[54] The emission factors presented in the table are for the Northeast NEMS (National Energy Modeling System) region, as defined by the EIA (tonto.eia.doe.gov/FTPROOT/modeldoc/m063(2001).pdf), pg 11.
[55] All emission factors are from the Gas Research Institute report, *Methane Emissions from the Natural Gas Industry*, Volume 8. Available at: epa.gov/gasstar/tools/related.html, unless otherwise noted.

Emission Source/ Equipment Type	CH_4 EFs	CO_2 EF	Units[55]	EF Reference	AF
Well Clean Ups (LP Gas Wells) (zero activity assumed for NYS Marcellus Shale)	0.261	0.00926	lbs/hr per low pressure well	Vol 6, page no. 18, table 4-2	0
Blowdowns					
Vessel BD	0.00041	0.00001	lbs/hr per vessel	Vol 6, page no. 18, table 4-2	4
Compressor BD	0.020	0.00071	lbs/hr per compressor	Vol 6, page no. 18, table 4-2	1
Compressor Starts	0.045	0.00158	lbs/hr per compressor	Vol 6, page no. 18, table 4-2	1
Upsets					
Pressure Relief Valves	0.00018	0.00001	lbs/hr per PRV	Vol 6, page no. 18, table 4-2	12

ii. VOC and HAP Emission Rates

EPA's AP-42[56] has lists of emission factors for various gas production sources. A worst case activity factor to use is 10 MMcf/day per well with a total of 8 wells at a pad. This equates to a fuel usage by an engine driving a compressor sized to this throughput of 1,075 MMBtu fuel gas per day[57]. Table 3.2-2 of AP-42 lists uncontrolled emission factors for 4-stroke lean-burn engines that can be applied to the wellpad compressor assumed in the worst case scenario.

Many other studies and guidance documents for air emissions[58,59,60] also apply AP-42 factors which reinforces their use as an industry standard appropriate for this effort. Note that the Wyoming DEQ permitting guidance document recommends using boiler emission factors for NOx and CO since the fuel gas combusted for these sources is a better match to production site gas flaring than the industrial flare gas compositions assumed by AP-42 for flares.

[56] AP-42, Fifth Edition, *Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources.* epa.gov/ttn/chief/ap42/index.html
[57] Pipeline Rules of Thumb Handbook, 4th edition. Horsepower selection chart, page 262. Assume 55 horsepower required per MMcfd of wellpad compression. Assume 25% thermal efficiency for the gas engine / reciprocating compressor package.
[58] *Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements*. Environmental Defense Fund. 26 Jan 2009. www.edf.org/documents/9235_Barnett_Shale_Report.pdf.
[59] Wyoming DEQ Air Quality Division. *Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance.* June 1997. August 2007 revision.
[60] Michigan DEQ, Environmental Science and Services Division. *Emission Calculation Fact Sheet*. Fact Sheet #9845. October, 2006.

BIBLIOGRAPHY

All Consulting. Evaluating the Environmental Implications of Hydraulic Fracturing in Shale Gas Reservoirs www.all-llc.com/shale/ArthurHydrFracPaperFINAL.pdf

American Petroleum Institute. Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry. February, 2004. Page 6-9

Argonne national Laboratory: EVS. Trip Report for Field Visit to Fayetteville Shale Gas Wells www.evs.anl.gov/pub/doc/ANL-EVS_R07-4TripReport.pdf

Bullin, Keith, et al. "Compositional Variety Complicates Processing Plans for US Shale Gas." Oil and Gas Journal. Vol 107, Issue 10. 9 March 2009. ogj.com/articles/article_display.cfm?ARTICLE_ID=355486&p=7&section=ARCHI&subsection=none&c=none&page=1&x=y&x=y&x=y

Bureau of Land Management: Wyoming. Hornbuckle Field Horizontal Drilling Program www.blm.gov/pgdata/etc/medialib/blm/wy/information/NEPA/cfodocs/hornbuckle.Par.11552.File.dat/ch2.pdf

"Compositional variety complicates processing plans for US shale gas" Oil and Gas Journal. Vol 107, Issue 10. 9 Mar 2009

Energy Information Administration. tonto.eia.doe.gov/FTPROOT/modeldoc/m063(2001).pdf, pg 11

Environmental Defense Fund. Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements. 26 Jan 2009. www.edf.org/documents/9235_Barnett_Shale_Report.pdf

EPA AP-42, Fifth Edition, Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. epa.gov/ttn/chief/ap42/index.html

EPA AP-42, Fifth Edition. Table 1.4-2 www.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf

EPA AP-42, Fifth Edition. Table 13.5-1. www.epa.gov/ttn/chief/ap42/ch13/final/c13s05.pdf

Final Statewide Oil and Gas EIS and Proposed Amendment of the Powder River and Billings RMP's (Montana CBM EIS) - www.deq.state.mt.us/CoalBedMethane/FinalEIS/Volume%20I/07%20Chapter-4.pdf

Gas Research Institute, Methane Emissions from the Natural Gas Industry, Volume 8. epa.gov/gasstar/tools/related.html

Gas Technology Institute. gastechnology.org/webroot/app/xn/xd.aspx?it=enweb&xd=10abstractpage\12352.xml

Jared Hall, East Resources Inc. General Mgr. Teleconference @ 2p.m. 4/13/09

M-I SWACO: Land Mud-Gas Separator Features & Benefits. www.miswaco.com/Products_and_Services/Drilling_Solutions/Pressure_Control/Mud_Gas_Separators/Mud_Gas_SeparatorsDocuments/LAND%20MUD-GAS%20SEPARATOR.cfm

Michigan DEQ, Environmental Science and Services Division. Emission Calculation Fact Sheet. Fact Sheet #9845. October, 2006

NY DEC SGEIS Information Request Responses from Fortuna, Chesapeake and East Resources

OSHA. www.osha.gov/SLTC/etools/oilandgas/illustrated_glossary/mud_return_line.html

Pennsylvania Department of Environmental Protection. Permit Workload Report. www.dep.state.pa.us/dep/deputate/minres/oilgas/new_forms/Marcellus/Marcellus.htm

Personal Contact, Kathleen Sanford, NYS DEC, 6/15/2009

Petrocasa Energy, Inc. www.petrocasa.com/3D%20Rig%20Animation%20Web%20Version/index.html

Pipeline Rules of Thumb Handbook, 4th edition. Horsepower selection chart, page 262

Summary of Chesapeake Delaware County applications for 23 horizontal well. Provided by Carrie Friello (NYS DEC)

U.S. Department of Energy (DOE). Office of Fossil Energy. "Modern Shale Gas Development in the United States: A Primer" A Primer www.all-llc.com/pdf/ShaleGasPrimer2009.pdf

U.S. Environmental Protection Agency. Frequent Questions. iaq.custhelp.com/cgi-bin/iaq.cfg/php/enduser/std_adp.php?p_faqid=3218

U.S. EPA. Natural Gas STAR Program. "Lessons Learned: Reducing Methane Emissions from Compressor Rod Packing Systems". www.epa.gov/gasstar/documents/ll_rodpack.pdf

U.S. EPA. Natural Gas STAR Program. "Lessons Learned: Replacing Glycol Dehydrators with Desiccant Dehydrators". www.epa.gov/gasstar/documents/ll_desde.pdf

U.S. EPA. Natural Gas STAR Program. "Lessons Learned: Vapor Recovery Tower/VRU Configuration". www.epa.gov/gasstar/documents/vrt_vru_configuration_08_21_07.pdf

U.S. EPA. Natural Gas STAR Program. Draft EPA Lessons Learned – Reduced Emissions Completions

US EPA. Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources. Chapter 13: Miscellaneous Sources. www.epa.gov/ttnchie1/ap42/ch13/final/c13s05.pdf

Wyoming DEQ Air Quality Division. Oil and Gas Production Facilities Chapter 6, Section 2 Permitting Guidance. June 1997. August 2007 revision

APPENDIX 2.1: EPA LESSONS LEARNED (DRAFT REDUCED EMISSION COMPLETIONS)

Reduced Emissions Completions

Executive Summary

High prices and high demand for natural gas, have seen the natural gas production industry move into development of the more technologically challenging unconventional gas reserves such as tight sands, shale and coalbed methane. Completion of new wells and re-working (workover) of existing wells in these tight formations typically involve hydraulic fracturing of the reservoir to increase well productivity. Removing the water and excess proppant (generally sand) during completion and well clean-up may result in significant releases of natural gas and methane emissions to the atmosphere. (The 40 BCF value is an extension of BP's venting for well-bore deliquification scaled up for the entire basin. It is not due to well clean-up post fracture stimulation)

Conventional completion of wells (a process that cleans the well bore of drill cuttings and fluid and fracture stimulation fluids and solids so that the gas has a free path from the reservoir) resulted in gas being either vented or flared. Vented gas resulted in large amounts of methane, volatile organic compounds (VOCs), and hazardous air pollutants (HAPs) emissions being released to the atmosphere, while flared gas resulted in carbon dioxide emissions.

Reduced emissions completions (RECs) – also known as reduced flaring completions or green completions – is a term used to describe an alternate practice that captures gas produced during well completions and well workovers following hydraulic fracturing. Portable equipment is brought on site to separate the gas from the solids and liquids produced during the completion and process this gas suitably for injection into the sales pipeline. Reduced emissions completions help to mitigate methane, VOC, and HAP emissions during well cleanup and can eliminate or significantly reduce the need for flaring.

RECs have become a popular practice among Natural Gas STAR production partners. A total of eight different partners have reported performing reduced emissions completions in their operations. RECs have become a major source of methane emission reductions since 2000. Between 2000 and 2005 emissions reductions from RECs have increased from 200 MMcf to over 7,000 MMcf. This represents additional revenue from natural gas sales of over $65 million in 2005 (assuming $7/Mcf gas prices).

Method for Reducing Gas Loss	Volume of Natural Gas Savings (Mcf/yr)[1]	Value of Natural Gas Savings ($/yr)[2]	Additional Savings ($/yr)[3]	Set-up Costs ($/yr)	Equipment Rental and Labor Costs ($)	Other Costs ($/yr)[4]	Payback (Months)[5]
Reduced Emissions Completion	270,000	1,890,000	197,500	15,000	212,500	129,500	3

1. Based on an annual REC program of 25 completions per year
2. Assuming $7/Mcf gas
3. Savings from recovering condensate and gas compressed to lift fluids
4. Cost of gas used to fuel compressor and lift fluids
5. Time required to recover the entire annual cost of the program