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Chapter 5 NATURAL GAS DEVELOPMENT ACTIVITIES AND HIGH-VOLUME HYDRAULIC FRACTURING

As noted in the GEIS, New York has a long history of natural gas production. The first gas well was drilled in 1821 in Fredonia, and the 40 billion cubic feet ("bcf") of gas produced in 1938 remained the production peak until 2004 when 46.9 bcf were produced. Annual production has exceeded 50 bcf every year since then. Chapters 9 and 10 of the GEIS comprehensively discuss well drilling, completion and production operations, including potential environmental impacts and mitigation measures. The history of hydrocarbon development in New York through 1988 is also covered in the GEIS.

New York counties with actively producing gas wells reported in 2008 were: Allegany, Cattaraugus, Cayuga, Chautauqua, Chemung, Chenango, Erie, Genesee, Livingston, Madison, Niagara, Oneida, Ontario, Oswego, Schuyler, Seneca, Steuben, Tioga, Wayne, Wyoming and Yates. Broome County saw production in 2007, but not in 2008.

5.1 Access Roads and Well Pads

5.1.1 Access Roads

The first step in developing a natural gas well site is to construct the access road and well pad. For environmental review and permitting purposes, the acreage and disturbance associated with the access road is considered part of the project as described by Topical Response #4 in the 1992 Final GEIS. However, instead of one well per access road as was typically the case when the GEIS was prepared, most shale gas development will consist of several wells on a multi-well pad serviced by a single access road. Therefore, in areas developed by horizontal drilling using multi-well pads, fewer access roads as a function of the number of wells will be needed.

Access road construction involves clearing the route and preparing the surface for movement of heavy equipment. Ground surface preparation typically involves placing a layer of crushed stone, gravel or cobbles over geotextile fabric. Sedimentation and erosion control features are also constructed as needed along the access roads and culverts may be placed across ditches at the entrance from the main highway or in low spots along the road.

The size of the access road is dictated by the size of equipment to be transported to the well site, distance of the well pad from an existing road and the route dictated by property access rights and environmental concerns. The route selected may not be the shortest distance to the nearest main road. Routes for access roads may be selected to make use of existing roads on a property and to avoid disturbing environmentally sensitive areas such as protected streams, wetlands, or steep slopes. Property access rights and agreements and traffic restrictions on local roads may also limit the location of access routes. Each 150 feet of a 30-foot wide access road adds about one-tenth of an acre to the total surface acreage disturbance attributed to the well site.

The Department has received applications for 47 horizontal Marcellus Shale wells to be developed in Broome, Chemung, Delaware and Tioga Counties by high-volume hydraulic fracturing. Using this set of applications as a demonstration of the kind of disturbances that can be anticipated in the placement of access roads, the proposed disturbed access road acreage for these sites ranges from 0.1 acres to 2.75 acres, with the access roads ranging from 130 feet to approximately 3,000 feet in length. Widths would range from 20 to 40 feet during the drilling and fracturing phase to 10 to 20 feet during the production phase. During the construction and drilling phase, additional access road width is necessary to accommodate stockpiled topsoil and excavated material along the roadway and to construct sedimentation and erosion control features such as berms, ditches, sediment traps or sumps, or silt fencing along the length of the access road. Pipelines may follow the access road, so additional clearing and disturbance may be conducted during the initial site construction phase to accommodate a future pipeline, adding to the access road width. Some proposals include a 20-foot access road with an additional 10-foot right-of-way. In the situations where pipelines do not follow an access road, sediment and erosion control measures will be followed.

Access roads will also be required for the centralized compression facilities and centralized water storage facilities that are described elsewhere in this document.

Photos 5.1 – 5.4 depict typical wellsite access roads.

5.1.1—Access Roads

Photo 5.1 Access road and erosion/sedimentation controls, Salo 1, Barton, Tioga County NY. Photo taken during drilling phase. This access road is approximately 1,400 feet long. Road width averages 22 feet wide, 28 feet wide at creek crossing (foreground). Width including drainage ditches is approximately 27 feet.
Source: NYS DEC 2007.

Photo 5.2 Nornew, Smyrna Hillbillies #2H, access road, Smyrna, Madison County NY. Photo taken during drilling phase of improved existing private dirt road (approximately 0.8 miles long). Not visible in photo is an additional 0.6 mile of new access road construction. Operator added ditches, drainage, gravel & silt fence to existing dirt road.
The traveled part of the road surface in the picture is 12.5' wide; width including drainage ditches is approximately 27 feet. Portion of the road crossing a protected stream is approximately 20 feet wide. Source: NYS DEC 2008.

Photo 5.3 In-service access road to horizontal Marcellus well in Bradford County, PA. Source: Chesapeake Energy

Photo 5.4 Access road and sedimentation controls, Moss 1, Corning, Steuben County NY. Photo taken during post-drilling phase. Access road at the curb is approximately 50 feet wide, narrowing to 33 feet wide between curb and access gate. The traveled part of the access road ranges between 13 and 19 feet wide. Access road length is approximately 1,100 feet long.
Source: NYS DEC 2004.

5.1.2 Well Pads

The activities associated with the preparation of a well pad are similar for both vertical wells and multi- well pads where horizontal drilling and high volume hydraulic fracturing will be used.[1] Site preparation activities consist primarily of clearing and leveling an area of adequate size and preparing the surface to support movement of heavy equipment. As with access road construction, ground surface preparation typically involves placing a layer of crushed stone, gravel or cobbles over geotextile fabric. Site preparation also includes establishing erosion and sediment control structures around the site, and constructing pits for retention of drilling fluid and, possibly, fresh water.

Depending on site topography, part of a slope may be excavated and the excavated material may be used as fill ("cut and fill" construction) to extend the well pad, providing for a level working area and more room for equipment and onsite storage. The fill banks must be stabilized using appropriate sedimentation and control measures.

The primary difference in well pad preparation for a well where high-volume hydraulic fracturing will be employed versus a well described by the 1992 GEIS is that more land is disturbed on a per-pad basis.[2] A larger well pad is required to accommodate fluid storage and equipment needs associated with the high-volume fracturing operations. In addition, some of the equipment associated with horizontal drilling has a larger surface footprint than the equipment described by the GEIS.

Again using the set of currently pending applications as an example the 47 proposed wells would be drilled on eleven separate well pads, with between two and six wells initially proposed for each pad. Proposed well pad sizes range from 2.2 acres to 5.5 acres during the drilling and fracturing phase of operations, and from 0.5 to 2 acres after partial reclamation during the production phase. Based on operators' responses to the Department's information requests and current activity in the northern tier of Pennsylvania, an average multi-well pad is likely to be between four and five acres in size during the drilling and fracturing phase, with well pads of

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[1] Alpha, 2009. p. 6-6.

[2] Alpha

over five acres possible. Average production pad size, after partial reclamation, is likely to average between 1 and 3 acres.

The well pad sizes discussed above are consistent with published information regarding drilling operations in other shale formations, as researched by ICF International for NYSERDA.[3] For example, 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 feet by 340 feet, or about 3.6 acres. This estimate does not include areas disturbed due to access road construction. A study of horizontal gas well sites constructed by SEECO, Inc. in the Fayetteville Shale reports that the operator generally clears 300 feet by 250 feet, or 1.72 acres, for its pad and reserve pits. Fayetteville Shale sites may be as large as 500 feet by 500 feet, or 5.7 acres.

Ultimately, as reported to NYSERDA by ICF International, pad size is determined by site topography, number of wells and pattern layout, with consideration given to the ability to stage, move and locate needed drilling and hydraulic fracturing equipment. Location and design of pits, impoundments, tanks, hydraulic fracturing equipment, reduced emission completion equipment, dehydrators and production equipment such as separators, brine tanks and associated control monitoring, as well as office and vehicle parking requirements, can increase square footage. Mandated surface restrictions and setbacks may also impose additional acreage requirements. On the other hand, availability and access to offsite, centralized dehydrators, compressor stations and impoundments may reduce acreage requirements for individual well pads. [4]

Photos 5.5 – 5.7 depict typical Marcellus well pads, and figure 5.1 is a schematic representation of a typical drilling site.

5.1.3 Well Pad Density5.1.3.1 Historic Well DensityWell owners reported 6,676 producing natural gas wells in New York in 2008, more than half ofwhich are in Chautauqua County. With 1,056 square miles of land in Chautauqua

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[3] ICF Subtask 2 Report, p. 4.

[4] ICF Subtask 2 report, pp. 4-5.

5.1.2 Typical Well Pads

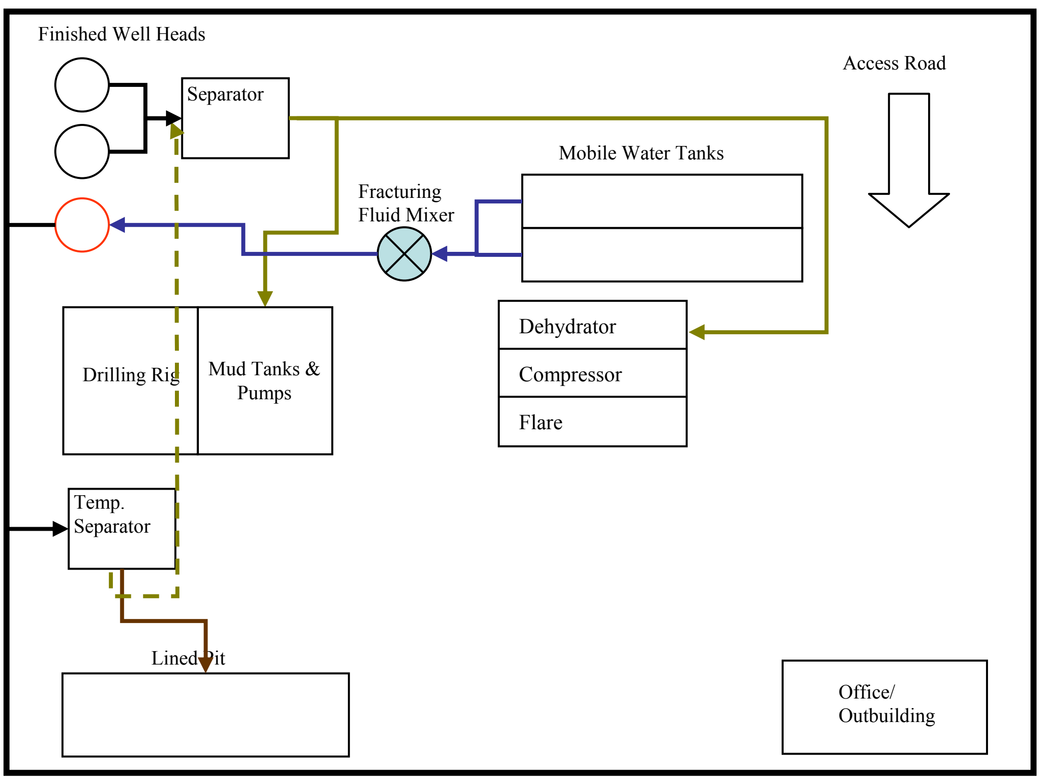
Photo 5.5 Chesapeake Energy Marcellus well drilling, Bradford County PA
Source: Chesapeake Energy

Photo 5.6 Hydraulic fracturing operation, horizontal Marcellus well, Upshur County, WV. Source: Chesapeake Energy, 2008

Photo 5.7 Hydraulic fracturing operation, horizontal Marcellus well, Bradford County, PA
Source: Chesapeake Energy, 2008

County, 3,456 reported producing wells equates to at least three producing wells per square mile. For the most part, these wells are at separate surface locations. Actual drilled density where the resource has been developed is somewhat greater than that, because not every well drilled is currently producing and some areas are not drilled. The Department issued 5,374 permits to drill in Chautauqua County between 1962 and 2008, or five permits per square mile. Of those permits, 63% or 3,396 were issued during a 10-year period between 1975 and 1984, for an average rate of 340 permits per year in a single county. Again, most of these wells were drilled at separate surface locations,

Figure 5-1 - Well Pad Schematic



Not to scale (As reported to NYSERDA by ICF International, derived from Argonne National Laboratory: EVS-Trip Report for Field Visit to Fayetteville Shale Gas Wells, plus expert judgment) each with its own access road and attendant disturbance. Although the number of wells is lower, parts of Seneca and Cayuga County have also been densely drilled. Many areas in all three counties – Chautauqua, Seneca and Cayuga – have been developed with "conventional" gas wells on 40-acre spacing (i.e., 16 wells per square mile, at separate surface locations). Therefore, while recognizing that some aspects of shale development activity will be different from what is described in the GEIS, it is worthwhile to note that this pre-1992 drilling rate and site density were part of the experience upon which the GEIS and its findings are based. Photos 5.8 through 5.11 are photos and aerial views of existing well sites in Chautauqua County, provided for informational purposes. As discussed above, well pads where high-volume hydraulic fracturing will be employed will necessarily be larger in order to accommodate the associated equipment. In areas developed by horizontal drilling, well pads will be less densely spaced, reducing the number of access roads and gathering lines needed.

5.1.3.2 Anticipated Well Pad Density

The number of wells and well sites that may exist per square mile is dictated by reservoir geology and productivity, mineral rights distribution, and statutory well spacing requirements set forth in ECL Article 23, Title 5, as amended in 2008. The statute provides three statewide spacing options for shale wells:

Vertical Wells

Statewide spacing for vertical shale wells provides for one well per 40-acre spacing unit. [5] This is the spacing requirement that has historically governed most gas well drilling in the State, and as mentioned above, many square miles of Chautauqua, Seneca and Cayuga counties have been developed on this spacing. One well per 40 acres equates to a density of 16 wells per square mile (i.e., 640 acres). Infill wells, resulting in more than one well per 40 acres, may be drilled upon justification to the Department that they are necessary to efficiently recover gas reserves. Gas well development on 40-acre spacing, with the possibility of infill wells, has been the prevalent gas well development method in New York for many decades. However, as reported by the Ground Water Protection Council,6 economic and technological considerations favor the use of horizontal drilling for shale gas development. As explained below, horizontal drilling

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[5] A spacing unit is the geographic area assigned to the well for the purposes of sharing costs and production. ECL §23-0501(2) requires that the applicant control the oil and gas rights for 60% of the acreage in a spacing unit for a permit to be issued. Uncontrolled acreage is addressed through the compulsory integration process set forth in ECL §23-0901(3).

[6] GPWC, 2009a. *Modern Shale Gas Development in the United States, A Primer,* pp. 46-47.

Natural Gas Wells in Chautauqua County

Year Permit Issued	Total
Pre-1962 (before permit program)	315
1962-1979	1,440
1980-1989	1,989
1990-1999	233
2000-2009	426
Grand Total	4,403

Photo 5.8 This map shows the locations of over 4,400 Medina formation natural gas wells in Chautauqua County from the Mineral Resources database. The wells were typically drilled on 40 to 80 acre well spacing, making the distance between wells at least 1/4 mile.

Readers can re-create this map by using the DEC on-line searchable database using County = Chautauqua and exporting the results to a Google Earth KML file.

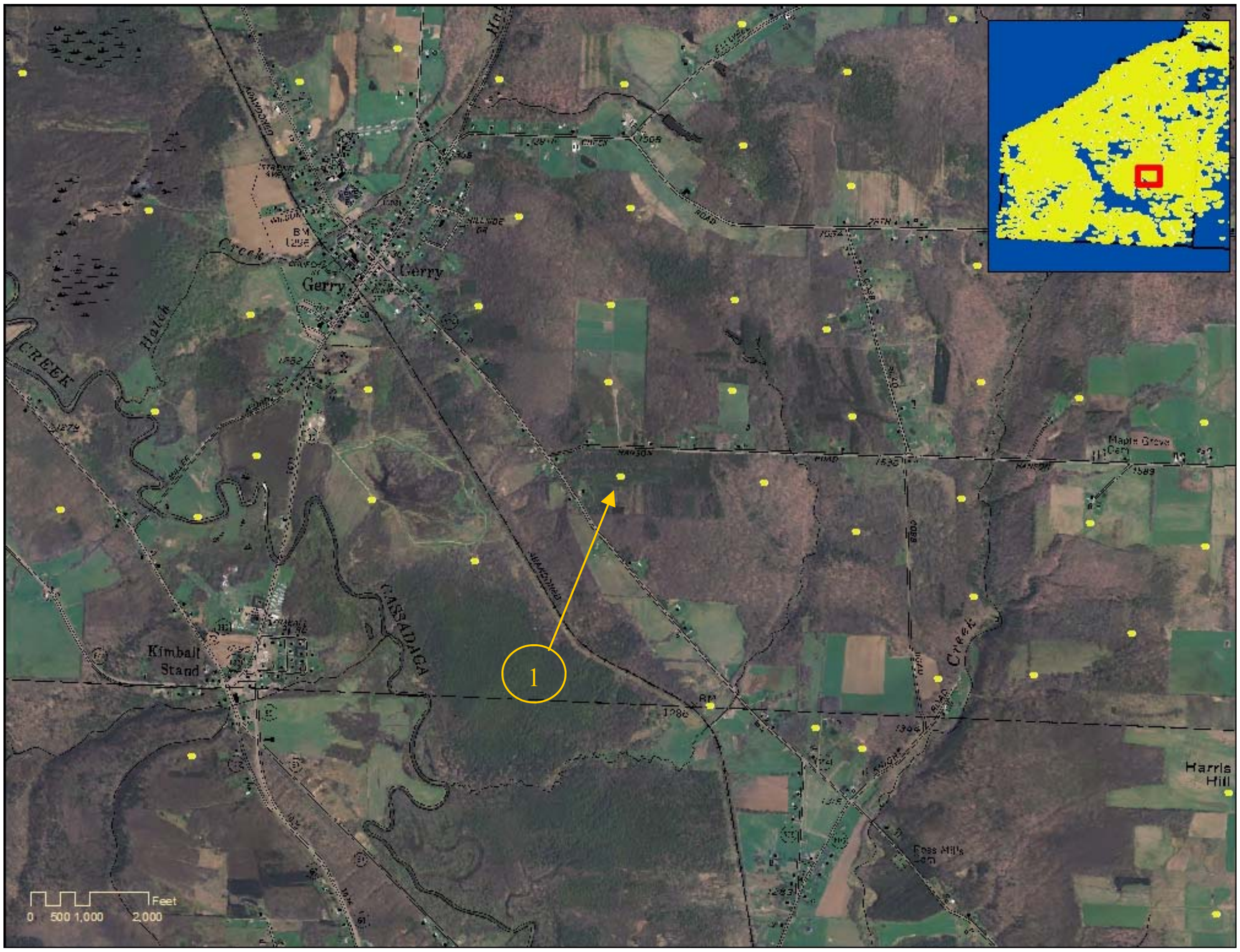

Photo 5.9 The above map shows a portion of the Chautauqua County map, near Gerry. Well #1 (API Hole number 25468) shown in the photo to the right was drilled and completed for production in 2008 to a total depth of 4,095 feet. Of the other 47 Medina gas wells shown above, the nearest is approximately 1,600 feet to the north.

These Medina wells use single well pads. Marcellus multi-well pads will be larger and will have more wellheads and tanks.

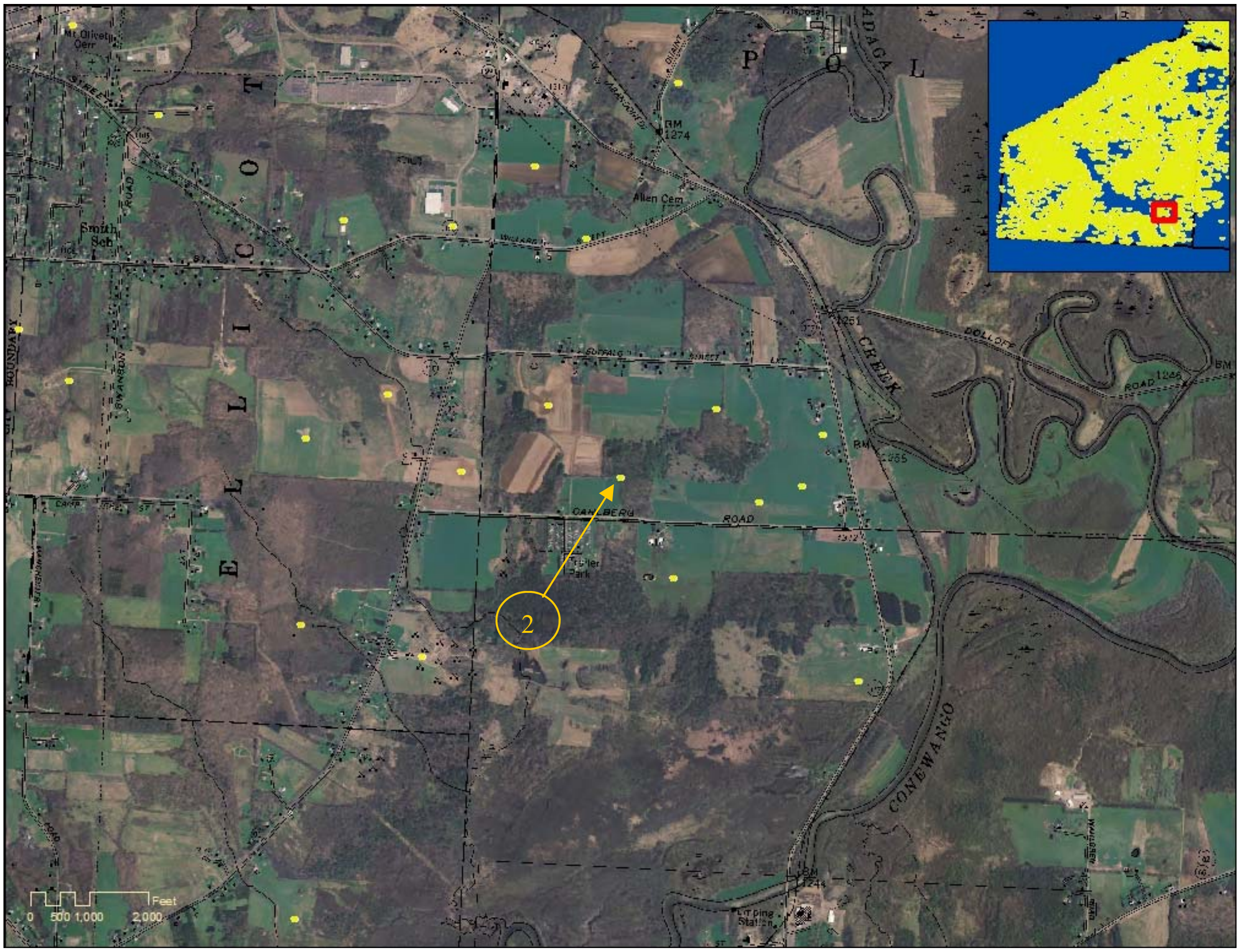

Photo 5.10 This map shows 28 wells in the Town of Poland, Chautauqua County. Well #2 (API Hole number 24422) was drilled in 2006 to a depth of 4,250 feet and completed for production in 2007. The nearest other well is 1,700 feet away.

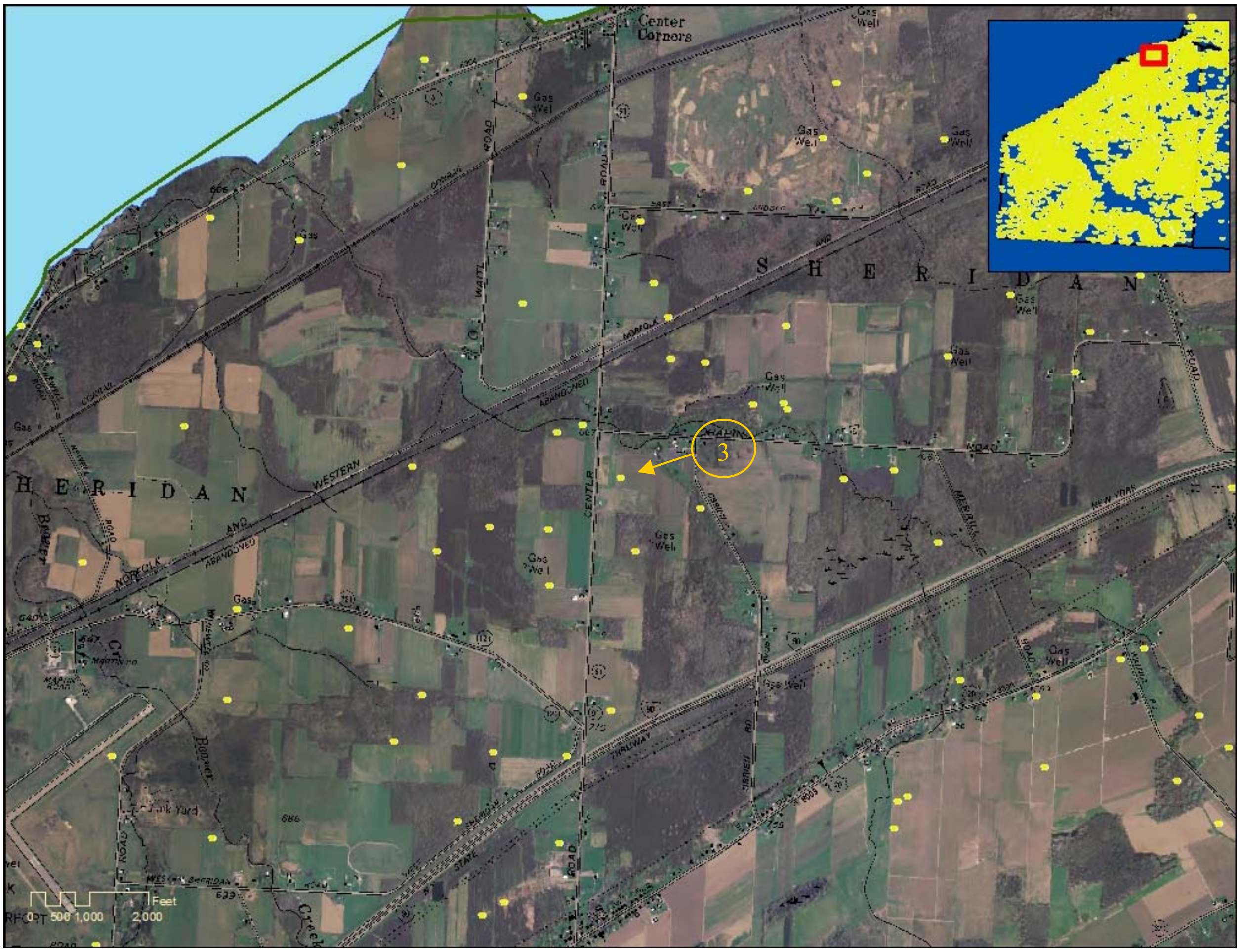

Photo 5.11 Well #3 (API Hole number 16427) in this photo was completed in the Town of Sheridan, Chautauqua County, in 1981 and was drilled to a depth of 2,012 feet.

This map shows 77 wells, with the nearest other producing well 1/4 mile away.

necessarily results in larger spacing units and reduced well pad density. Although legal, vertical drilling, 40-acre well spacing, and 16 well pads per square mile are not expected to be typical for shale gas development in New York using high-volume hydraulic fracturing.

Horizontal Wells in Single-Well Spacing Units

Statewide spacing for horizontal wells where only one well will be drilled at the surface site provides for one well per 40 acres plus the necessary and sufficient acreage to maintain a 330-foot setback between the wellbore in the target formation and the spacing unit boundary. This provision does not provide for horizontal infill wells, so both the width of the spacing unit and the distance within the target formation between wellbores in adjacent spacing units will always be at least 660 feet. Surface locations may be somewhat closer together because of the need to begin building angle in the wellbore about 500 feet above the target formation. However, unless the horizontal length of the wellbores within the target formation is limited to 1,980 feet, the spacing units will exceed 40 acres in size. Although it is possible to drill horizontal wellbores of this length, all information provided to date indicates that, in actual practice, lateral distance drilled will normally exceed 2,000 feet and would most likely be 3,500 feet or more, requiring substantially more than 40 acres. Therefore, the overall density of surface locations would be less than 16 wells per square mile. For example, with 4,000 feet as the length of a horizontal wellbore in the target shale formation, a spacing unit would be 4,660 feet long by 660 feet wide, or about 71 acres in size. Nine, instead of 16, spacing units would fit within a square mile, necessitating nine instead of 16 access roads and nine instead of 16 gas gathering lines.

Horizontal Wells with Multiple Wells Drilled from Common Pads

The third statewide spacing option for shale wells provides, initially, for spacing units of up to 640 acres with all the horizontal wells in the unit drilled from a common well pad. Vertical infill wells may be drilled, with justification, from separate surface locations in the unit. However, a far smaller proportion of vertical infill wells than 15 per 640-acre unit is expected. Therefore, fewer than 16 separate locations within a square mile area will be affected. This method, which also provides the most flexibility to avoid environmentally sensitive locations within the acreage to be developed, is expected to be the most common approach to shale gas development in New York using horizontal drilling and high-volume hydraulic fracturing.

With respect to overall land disturbance, the larger surface area of an individual multi-well pad will be more than offset by the fewer total number of well pads within a given area and the need for only a single access road and gas gathering system to service multiple wells on a single pad. Overall, there clearly is a smaller total area of land disturbance associated with horizontal wells for shale gas development than that for vertical wells.[7] For example, a spacing of 40 acres per well for vertical shale gas wells would result in 32 - 48 acres of well pad disturbance (2 - 3 acres per well) to develop an area of 640 acres, plus the additional acreage to construct access roads to each of the 16 well pads. A single well pad with 6 to 8 horizontal shale gas wells could access all 640 acres. This translates to a maximum of 4 to 6 acres of well pad disturbance, plus a single access road, compared with 32 acres of well pad disturbance plus access roads to develop the same area using vertical shale gas wells.

Table 5.1 below provides another comparison between the well pad acreage disturbed within a 10-square mile area completely developed by multi-well pad horizontal drilling versus single-well pad vertical drilling.[8]

Table 5-1 - Ten square mile area (i.e., 6,400 acres), completely drilled with horizontal wells in multi-well units or vertical wells in single-well units

Spacing Option	**Multi-Well 640 Acre**	**Single-Well 40 Acre**
Number of Pads	10	160
Total Disturbance - Drilling Phase	50 Acres (5 ac. per pad)	480 Acres (3 ac. per pad)
% Disturbance - Drilling Phase	.78	7.5
Total Disturbance - Production Phase	30 Acres (3 ac. per pad)	240 Acres (1.5 ac. per pad)
% Disturbance - Production Phase	.46	3.75

Variances or Non-Conforming Spacing Units

The statute has always provided for variances from statewide spacing or non-conforming spacing units, with justification, which could result in a greater well density for any of the above options. A variance from statewide spacing or a non-conforming spacing unit requires the Department to issue a well-specific spacing order following public comment and, if necessary, an adjudicatory hearing. Environmental impacts associated with any well to be drilled under a spacing order will

[7] Alpha, 2009. p. 6-2

[8] NTC, 2009, p. 29

continue to be reviewed separately from the spacing variance upon receipt of a specific well permit application.

5.2 Horizontal Drilling

The first horizontal well in New York was drilled in 1989, and in 2008 approximately 10% of the well permit applications received by the Department were for directional or horizontal wells. The predominant use of horizontal drilling associated with natural gas development in New York has been for production from the Black River and Herkimer formations during the past several years. The combination of horizontal drilling and hydraulic fracturing is widely used in other areas of the United States as a means of recovering gas from tight shale formations.

Except for the use of specialized downhole tools, horizontal drilling is performed using similar equipment and technology as vertical drilling, with the same protocols in place for aquifer protection, fluid containment and waste handling. As described below, there are four primary differences between horizontal drilling for shale gas development and the drilling described in the 1992 GEIS. One is that larger rigs may be used for all or part of the drilling, with longer per-well drilling times than were described in the GEIS. The second is that multiple wells will be drilled from each well site (or "well pad"). The third is that drilling mud rather than air may be used while drilling the horizontal portion of the wellbore to lubricate and cool the drill bit and to clean the wellbore. Fourth and finally, the volume of rock cuttings returned to the surface from the target formation will be greater for a horizontal well than for a vertical well.

Vertical drilling depth will vary based on target formation and location within the state. Chapter 5 of the GEIS discusses New York State's geology with respect to oil and gas production. Chapter 4 of this SGEIS expands upon that discussion, with emphasis on the Marcellus and Utica Shales. Chapter 4 includes maps which show depths and thicknesses related to these two shales.

In general, wells will be drilled vertically to a depth of about 500 feet above the top of a target interval, such as the Union Springs Member of the Marcellus Shale. Drilling may continue with the same rig, or a larger drill rig may be brought onto the location to build angle and drill the horizontal portion of the wellbore. A downhole motor behind the drill bit at the end of the drill pipe is used to accomplish the angled drilling. The drill pipe is also equipped with inclination and azimuth sensors located about 60 feet behind the drill bit to continuously record and report the drill bit's location. The length of the horizontal wellbore may be affected by the operator's lease position or compulsory integration status within the spacing unit, but based on existing applications and current operations in the northern tier of Pennsylvania a typical length may be 4,500 feet.

5.2.1 Drilling Rigs

Wells for shale gas development using high-volume hydraulic fracturing will be drilled with rotary rigs. Rotary rigs are described in the 1992 GEIS, with the typical rotary rigs used in New York at the time characterized as either 40 to 45-foot high "singles" or 70 to 80-foot high "doubles." These rigs can, respectively, hold upright one joint of drill pipe or two connected joints. "Triples," which hold three connected joints of drill pipe upright and are over 100 feet high, were not commonly used in New York State when the GEIS was prepared. However, triples have been more common in New York since 1992 for natural gas storage field drilling and to drill some Trenton-Black River wells.

Operators may use one large rig to drill an entire wellbore from the surface to toe of the horizontal bore, or may use two or three different rigs in sequence. For each well, only one rig is over the hole at a time. At a multi-well site, two rigs may be present on the pad at once, but more than two are unlikely because of logistical and space considerations as described below.

When two rigs are used to drill a well, a smaller rig of similar dimensions to the typical rotary rigs described in the GEIS would first drill the vertical portion of the well. Only the rig used to drill the horizontal portion of the well is likely to be significantly larger than what is described in the GEIS. This rig may be a triple, with a substructure height of about 20 feet, a mast height of about 150 feet, and a surface footprint with its auxiliary equipment of about 14,000 square feet. Auxiliary equipment includes various tanks (for water, fuel and drilling mud), generators, compressors, solids control equipment (shale shaker, de-silter, de-sander), choke manifold, accumulator, pipe racks and the crew's office space (or "dog house"). Initial work with the smaller rig would typically take up to two weeks, followed by another up to two weeks of work with the larger rig. These estimates include time for casing and cementing the well, and may be extended if drilling is slower than anticipated because of properties of the rock, or if other problems or unexpected delays occur.

When three rigs are used to drill a well, the first rig is used to drill and case the conductor hole. This event generally takes about 8 to12 hours. The dimensions of this rig would be consistent with what is described in the GEIS. The second rig for drilling the remainder of the vertical hole would also be consistent with GEIS descriptions and would again typically be working for up to 14 days, or longer if drilling is slow or problems occur. The third rig, equipped to drill horizontally, would be the only one that might exceed GEIS dimensions, with a substructure height of about 20 feet, a mast height of about 150 feet, and a surface footprint with its auxiliary equipment of about 14,000 square feet. Work with this rig would take up to 14 days, or longer if drilling is slow or other problems or delays occur.

Appendix 7 includes sample rig specifications provided by Chesapeake Energy. As noted on the specs, fuel storage tanks associated with the larger rigs would hold volumes of 10,000 to 12,000 gallons.

In summary, the rig work for a single horizontal well – including drilling, casing and cementing – would generally last about four to five weeks, subject to extension for slow drilling or other unexpected problems or delays. A 150-foot tall, large-footprint rotary rig may be used for the entire duration or only for the actual horizontal drilling. In the latter case, smaller, GEIS-consistent rigs would be used to drill the vertical portion of the wellbore. The rig and its associated auxiliary equipment would move off the well before fracturing operations commence.

Photos 5.12 – 5.15 are photographs of drilling rigs.

5.2.2 Drill Rigs

Photo 5.12 Double. Union Drilling Rig 54, Olsen 1B, Town of Fenton, Broome County NY. Credit: NYS DEC 2005.

Photo 5.13 Double. Union Drilling Rig 48. Trenton-Black River well, Salo 1, Town of Barton, Tioga County NY. Source: NYS DEC 2008.

Photo 5.14 Triple. Precision Drilling Rig 26. Ruger 1 well, Horseheads, Chemung County. Credit: NYS DEC 2009.

Photo 5.15 Top Drive Single. Barber and DeLine rig, Sheckells 1, Town of Cherry Valley, Otsego County. Credit: NYS DEC 2007.

5.2.2 Multi-Well Pad Development

Horizontal drilling from multi-well pads is the common development method employed to develop Marcellus Shale reserves in the northern tier of Pennsylvania and is expected to be common in New York as well. To prevent operators in New York from holding acreage within large spacing units without fully developing the acreage, the Environmental Conservation Law requires that all horizontal wells in a multi-well shale unit be drilled within three years of the date the first well in the unit commences drilling.[9]

As described above, the space required for hydraulic fracturing operations for a multi-well pad is dictated by a number of factors but is expected to most commonly range between four and five acres. The well pad is typically centered in the spacing unit, with surface locations generally about 12 to 20 feet apart. Within the target formation, evenly spaced parallel horizontal bores are drilled in opposite directions. Up to 16 surface locations, but more commonly six or eight, would be arranged in two parallel rows. When fully developed, the resultant horizontal well pattern underground would resemble two back-to-back pitchforks. [Figure 5.2]

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[9] ECL §23-0501

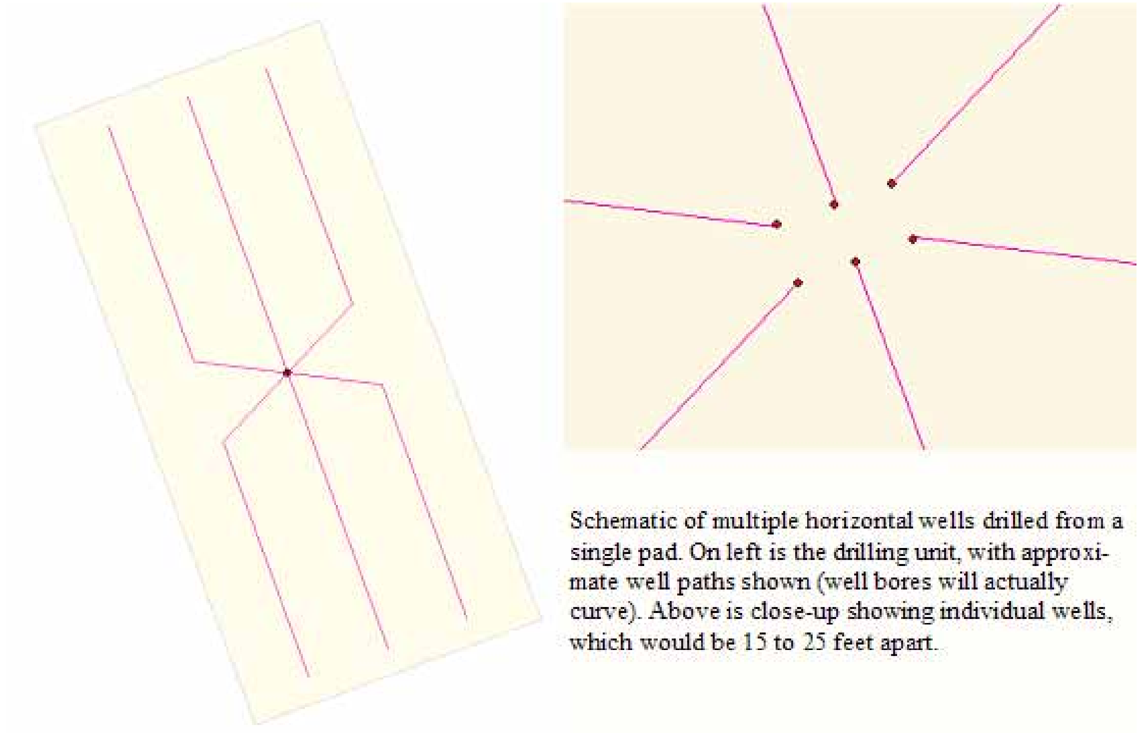

Figure 5-2 – Well spacing unit and wellbore paths

Because of the close well spacing at the surface, most operators have indicated that only one drilling rig at a time would be operating on any given well pad. One operator has stated that on a well pad where six or more wells are needed, it is possible that two triple-style rigs may operate concurrently. Efficiency and the economics of mobilizing equipment and crews would dictate that all wells on a pad be drilled sequentially, with continuous activity during a single mobilization. However, this may be affected by the timing of compulsory integration proceedings if wellbores are proposed to intersect unleased acreage.[10] Other considerations may result in gaps between well drilling episodes at a well pad. For instance, early development in a given area may consist of initially drilling and stimulating one to three wells on a pad to test productivity, followed by the additional wells within the required three-year time frame. As development in a given area matures and the results become more predictable, the frequency of drilling and completing all the wells on each pad with continuous activity in a single mobilization would be expected to increase.

[10] ECL §23-0501 2.b. prohibits the wellbore from crossing unleased acreage prior to issuance of a compulsory integration order.

5.2.2.1 Reserve Pits on Multi-Well Pads

The GEIS describes the construction, use and reclamation of lined reserve pits, (also called "drilling pits" or "mud pits") to hold cuttings and fluids associated with the drilling process. Rather than using a separate pit for each well on a multi-well pad, operators may propose to maintain a single pit on the well pad until all wells are drilled and completed. The pit would need to be adequately sized to hold cuttings from all the wells, unless the cuttings are removed intermittently as needed to ensure adequate room for drilling-associated fluids and precipitation. Under existing regulations, fluid associated with each well would have to be removed within 45 days of the cessation of drilling operations, unless the operator has submitted a plan to use the fluids in subsequent operations and the Department has inspected and approved the pit.[11]

5.2.3 Drilling Mud

The vertical portion of each well, including the portion that is drilled through any fresh water aquifers, will typically be drilled using either compressed air or freshwater mud as the drilling fluid. Operators who provided responses to the Department's information requests stated that the horizontal portion, drilled after any fresh water aquifers are sealed behind cemented surface casing, may be drilled with a mud that may be water-based, potassium chloride/polymer-based with a mineral oil lubricant, or synthetic oil-based. Synthetic oil-based muds are described as "food-grade" or "environmentally friendly." When drilling horizontally, mud is needed for (1) powering and cooling the downhole motor used for directional drilling, (2) using navigational tools which require mud to transmit sensor readings, (3) providing stability to the horizontal borehole while drilling and (4) efficiently removing cuttings from the horizontal hole. Other operators may drill the horizontal bore on air, using special equipment to control fluids and gases that enter the wellbore. Historically, most wells in New York are drilled on air and air drilling is addressed by the GEIS.

As described in the GEIS, used drilling mud is typically reconditioned for use at a subsequent well. It is managed on-site by the use of steel tanks that are part of the rig's "mud system." Some drilling rigs are equipped with closed-loop tank systems, so that neither used mud nor cuttings are discharged to reserve pits.

[11] 6 NYCRR 554.1(c)(3)

Photo 5.16 - Drilling rig mud system (blue tanks)

5.2.4 Cuttings

The very fine-grained rock fragments removed by the drilling process are returned to the surface in the drilling fluid and managed either within a closed-loop tank system or a lined on-site reserve pit.[12] As described in Section 5.13.1, the proper disposal method for cuttings is determined by the composition of drilling fluids used to return them to the surface.

5.2.4.1 Cuttings Volume

Horizontal drilling penetrates a greater linear distance of rock and therefore produces a larger volume of drill cuttings than does a well drilled vertically to the same depth below the ground surface. For example, a vertical well drilled to a total depth of 7,000 feet produces approximately 125 cubic yards of cuttings, while a horizontally drilled well to the same target

[12] Alpha

depth with a 3,000 foot lateral section produces approximately 165 cubic yards of cuttings (i.e., about one-third more). A multi-well site would produce that volume of cuttings from each well.

5.2.4.2 Naturally Occurring Radioactive Materials in Marcellus Cuttings

To determine NORM concentrations and the potential for exposure to Marcellus rock cuttings and cores, the Department conducted field and sample surveys using portable Geiger counter and gamma ray spectroscopy methods. Gamma ray spectroscopy analyses were performed on composited Marcellus samples collected from two vertical wells drilled through the Marcellus, one in Lebanon (Madison County), and one in Bath (Steuben County). Department staff also used a Geiger counter to screen three types of Marcellus samples: cores from the New York State Museum's collection in Albany; regional outcrops of the unit; and various Marcellus well sites from the west-central part of the state, where most of the vertical Marcellus wells in NYS are currently located. These screening data are presented in Table 5.2. The results, which indicate levels of radioactivity that are essentially background values, do not indicate an exposure concern for workers or the general public associated with Marcellus cuttings.

Table 5-2 - 2009 Marcellus Radiological Screening Data

Well (Depth)	API #	Date Collected	Town (County)	Parameter	Result +/- Uncertainty
Crouch C 4H (1040 feet - 1115 feet)	31-053-26305-00-00	3/17/09	Lebanon (Madison)	K-40	14.438 +/- 1.727 pCi/g
				Tl-208	0.197 +/- 0.069 pCi/g
				Pb-210	2.358 +/- 1.062 pCi/g
				Bi-212	0.853 +/- 0.114 pCi/g
				Bi-214	1.743 +/- 0.208 pCi/g
				Pb-214	1.879 +/- 0.170 pCi/g
				Ra-226	1.843 +/- 0.573 pCi/g
				Ac-228	0.850 +/- 0.169 pCi/g
				Th-234	1.021 +/- 0.412 pCi/g
				U-235	0.185 +/- 0.083 pCi/g
Blair 2A (2550' - 2610')	31-101-02698-01-00	3/26/09	Bath (Steuben)	K-40	22.845 +/- 2.248 pCi/g
				Tl-208	0.381 +/- 0.065 pCi/g
				Pb-210	0.535 +/- 0.712 pCi/g
				Bi-212	1.174 +/- 0.130 pCi/g
				Bi-214	0.779 +/- 0.120 pCi/g
				Pb-214	0.868 +/- 0.114 pCi/g
				Ra-226	0.872 +/- 0.330 pCi/g
				Ac-228	1.087 +/- 0.161 pCi/g
				Th-234	0.567 +/- 0.316 pCi/g
				U-235	0.079 +/- 0.058 pCi/g

Media Screened	Well	Date	Location (County)	Results
Cores	Beaver Meadow 1	3/12/09	NYS Museum (Albany)	0.005 - 0.080 mR/hr
	Oxford 1	3/12/09	NYS Museum (Albany)	0.005 - 0.065 mR/hr
	75 NY-14	3/12/09	NYS Museum (Albany)	0.015 - 0.065 mR/hr
	EGSP #4	3/12/09	NYS Museum (Albany)	0.005 - 0.045 mR/hr
	Jim Tiede	3/12/09	NYS Museum (Albany)	0.005 - 0.025 mR/hr
	75 NY-18	3/12/09	NYS Museum (Albany)	0.005 - 0.045 mR/hr
	75 NY-12	3/12/09	NYS Museum (Albany)	0.015 - 0.045 mR/hr
	75 NY-21	3/12/09	NYS Museum (Albany)	0.005 - 0.040 mR/hr
	75 NY-15	3/12/09	NYS Museum (Albany)	0.005 - 0.045 mR/hr
	Matejka	3/12/09	NYS Museum (Albany)	0.005 - 0.090 mR/hr
Outcrops	N/A	3/24/2009	Onesquethaw Creek (Albany)	0.02 - 0.04 mR/hr
	N/A	3/24/2009	DOT Garage, CR 2 (Albany)	0.01 - 0.04 mR/hr
	N/A	3/24/2009	SR 20, near SR 166 (Otsego)	0.01 - 0.04 mR/hr
	N/A	3/24/2009	Richfield Springs (Otsego)	0.01 - 0.06 mR/hr
	N/A	3/24/2009	SR 20 (Otsego)	0.01 - 0.03 mR/hr
	N/A	3/24/2009	Gulf Rd (Herkimer)	0.01 - 0.04 mR/hr
Well Sites	Beagell 2B	4/7/2009	Kirkwood (Broome)	0.04 mR/hr *
	Hulsebosch 1	4/2/2009	Elmira City (Chemung)	0.03 mR/hr *
	Bush S1	4/2/2009	Elmira (Chemung)	0.03 mR/hr *
	Parker 1	4/7/2009	Oxford (Chenango)	0.05 mR/hr *
	Donovan Farms 2	3/30/2009	West Sparta (Livingston)	0.03 mR/hr *
	Fee 1	3/30/2009	Sparta (Livingston)	0.02 mR/hr *
	Meter 1	3/30/2009	West Sparta (Livingston)	0.03 mR/hr *
	Schiavone 2	4/6/2009	Reading (Schuyler)	0.05 mR/hr *
	WGI 10	4/6/2009	Dix (Schuyler)	0.07 mR/hr *
	WGI 11	4/6/2009	Dix (Schuyler)	0.07 mR/hr *
	Calabro T1	3/26/2009	Orange (Schuyler)	0.03 mR/hr *
	Calabro T2	3/26/2009	Orange (Schuyler)	0.05 mR/hr *
	Frost 2A	3/26/2009	Orange (Schuyler)	0.05 mR/hr *
	Webster T1	3/26/2009	Orange (Schuyler)	0.05 mR/hr *
	Haines 1	4/1/2009	Avoca (Steuben)	0.03 mR/hr *
	Haines 2	4/1/2009	Avoca (Steuben)	0.03 mR/hr *
	McDaniels 1A	4/1/2009	Urbana (Steuben)	0.03 mR/hr *
	Drumm G2	4/1/2009	Bradford (Steuben)	0.07 mR/hr *
	Hemley G2	3/26/2009	Hornby (Steuben)	0.03 mR/hr *
	Lancaster M1	3/26/2009	Hornby (Steuben)	0.03 mR/hr *
	Maxwell 1C	4/2/2009	Caton (Steuben)	0.07 mR/hr *
	Scudder 1	3/26/2009	Bath (Steuben)	0.03 mR/hr *
	Blair 2A	3/26/2009	Bath (Steuben)	0.03 mR/hr *
	Retherford 1	4/1/2009	Troupsburg (Steuben)	0.05 mR/hr *
	Carpenter 1	4/1/2009	Troupsburg (Steuben)	0.05 mR/hr *
	Cook 1	4/1/2009	Troupsburg (Steuben)	0.05 mR/hr *
	Zinck 1	4/1/2009	Woodhull (Steuben)	0.07 mR/hr *
	Tiffany 1	4/7/2009	Owego (Tioga)	0.03 mR/hr *

5.3 Hydraulic Fracturing - Introduction

Hydraulic fracturing is a well stimulation technique which consists of pumping a fluid and a propping agent ("proppant") such as sand down the wellbore under high pressure to create fractures in the hydrocarbon-bearing rock. No blast or explosion is created by the hydraulic fracturing process. The proppant holds the fractures open, allowing hydrocarbons to flow into the wellbore after injected fluids are recovered. Hydraulic fracturing technology was first developed in the late 1940s and, accordingly, it was addressed in the GEIS. It is estimated that as many as 90% of wells drilled in New York are hydraulically fractured. ICF International provides the following history:[13]

Hydraulic Fracturing Technological Milestones [14]	
Early 1900s	Natural gas extracted from shale wells. Vertical wells fracked with foam.
1983	First gas well drilled in Barnett Shale in Texas
1980-1990s	Cross-linked gel fracturing fluids developed and used in vertical wells
1991	First horizontal well drilled in Barnett Shale
1991	Orientation of induced fractures identified
1996	Slickwater fracturing fluids introduced
1996	Microseismic post-fracturing mapping developed
1998	Slickwater refracturing of originally gel-fracked wells
2002	Multi-stage slickwater fracturing of horizontal wells
2003	First hydraulic fracturing of Marcellus shale[15]
2005	Increased emphasis on improving the recovery factor
2007	Use of multi-well pads and cluster drilling

The GEIS discusses, in Chapter 9, hydraulic fracturing operations using water-based gel and foam, and describes the use of water, hydrochloric acid and additives including surfactants, bactericides,[16] clay and iron inhibitors and nitrogen. The fracturing fluid is an engineered product; service providers vary the design of the fluid based on the characteristics of the

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[13] ICF International, 2009. *Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program.* NYSERDA Agreement No. 9679. p. 3.

[14] Matthews, 2008, as cited by ICF International, 2009.

[15] Harper, 2008, as cited by ICF International, 2009.

[16] Bactericides must be registered for use in New York in accordance with ECL §33-0701. Well operators, service companies, and chemical supply companies were reminded of this requirement in an October 28, 2008 letter from the Division of Mineral Resources formulated in consultation with the Division of Solid and Hazardous Materials. This correspondence also reminded industry of the corresponding requirement that all bactericides be properly labeled and that the labels for such products be kept on-site during application and storage.

reservoir formation and the well operator's objectives. In the late 1990's, operators and service companies in other states developed a technology known as "slickwater fracturing" to develop shale formations, primarily by increasing the amount and proportion of water used, reducing the use of gelling agents and adding friction reducers. Any fracturing fluid may also contain scale and corrosion inhibitors.

ICF International, who reviewed the current state of practice of hydraulic fracturing for NYSERDA, states that the development of water fracturing technologies has reduced the quantity of chemicals required to hydraulically fracture target reservoirs and that slickwater treatments have yielded better results than gel treatments in the Barnett Shale.[17] Poor proppant suspension and transport characteristics of water versus gel are overcome by the low permeability of shale formations which allow the use of finer-grained proppants and lower proppant concentrations.[18] The use of friction reducers in slickwater fracturing procedures reduce the required pumping pressure at the surface, thereby reducing the number and power of pumping trucks needed.[19] In addition, according to ICF, slickwater fracturing causes less formation damage than other techniques such as gel fracturing.[20]

Both slickwater fracturing and foam fracturing have been proposed for Marcellus Shale development. As foam fracturing is already addressed by the GEIS, this document focuses on slickwater fracturing. This type of hydraulic fracturing is referred to herein as "high-volume hydraulic fracturing" because of the large water volumes required.

5.4 Fracturing Fluid

The fluid used for slickwater fracturing is typically comprised of more than 98% fresh water and sand, with chemical additives comprising 2% or less of the fluid.[21] The Department has collected compositional information on many of the additives proposed for use in fracturing shale formations in New York directly from chemical suppliers and service companies. This

[17] ICF International, 2009. *Technical Assistance for the Draft Supplemental Generic EIS: Oil, Gas and Solution Mining Regulatory Program.* NYSERDA Agreement No. 9679. pp. 10, 19.

[18] Ibid.

[19] Ibid., p. 12.

[20] Ibid., p. 19.

[21] GWPC, 2009a. *Modern Shale Gas Development in the United States: A Primer*, pp. 61-62.

information has been evaluated by the Department's Air Resources and Water Divisions as well as the Bureaus of Water Supply Protection and Toxic Substances Assessment in the New York State Department of Health. It has also been reviewed by technical consultants contracted by NYSERDA[22] to conduct research related to the preparation of this document. Discussion of potential environmental impacts and mitigation measures in Chapters 6 and 7 of this SGEIS reflect analysis and input by all of the foregoing entities.

Six service companies[23] and twelve chemical suppliers[24] have provided additive product compositional information to the Department that includes more complete information than is available on product Material Safety Data Sheets (MSDSs)[25]. Altogether, some compositional information is on file with the Department for 197 products, with complete compositional information on file for 152 of those products. Within these products are approximately 260 unique chemicals whose CAS Numbers have been disclosed to the Department and an additional 40 compounds which require further disclosure since many are mixtures. Table 5.3 is an alphabetical list of all products for which complete chemical information has been provided to the Department. Table 5.4 is an alphabetical list of products for which only partial chemical composition information has been provided to the Department. Any product whose name does not appear within Table 5.3 or Table 5.4 was not evaluated in this SGEIS either because no chemical information was submitted to the Department or because the product was not proposed for use in fracturing operations at Marcellus shale wells or other wells targeting other low-permeability gas reservoirs. MSDSs are on file with the Department for most of the products listed. The Department considers MSDSs to be public information ineligible for exception from disclosure as trade secrets or confidential business information.

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[22] Alpha Environmental Consultants, Inc., ICF International, URS Corporation

[23] BJ Services, Frac Tech Services, Halliburton, Superior Well Services, Universal Well Services, Schlumberger, Superior Well Services

[24] Baker Petrolite, CESI/Floteck, Champion Technologies/Special Products, Chem EOR, Cortec, Industrial Compounding, Kemira, Nalco, PfP Technologies, SNF Inc., Weatherford/Clearwater, and WSP Chemicals & Technology

[25] MSDSs are designed to provide employees and emergency personnel with proper procedures for handling, working with, and storing a particular substance and are regulated by the Occupational Safety and Health Administration (OSHA)'s Hazard Communication Standard, 29 CFR 1910.1200(g).

Table 5-3 Fracturing Additive Products – Full Composition Disclosure Made to the Department

Product Name
ABF
Acetic Acid 0.1-10%
Acid Pensurf / Pensurf
Activator W
AGA 150 / Super Acid Gell 150
AI-2
Aldacide G
Alpha 125
Ammonium Persulfate/OB Breaker
APB-1, Ammonium Persulfate Breaker
AQF-2
ASP-820
B315 / Friction Reducer B315
B317 / Scale Inhibitor B317
B859 / EZEFLO Surfactant B859 / EZEFLO F103 Surfactant
B867 / Breaker B867 / Breaker J218
B868 / EB-CLEAN B868 LT Encapsulated Breaker / EB-Clean J479 LT Encapsulated Breaker
B869 / Corrosion Inhibitor B869 / Corrosion Inhibitor A262
B875 / Borate Crosslinker B875 / Borate Crosslinker J532
B880 / EB-CLEAN B880 Breaker / EB-CLEAN J475 Breaker
B890 / EZEFLO Surfactant B890 / EZEFLO F100 Surfactant
B900 / EZEFLO Surfactant B900/ EZEFLO F108 Surfactant
B910 / Corrosion Inhibitor B910 / Corrosion Inhibitor A264
B916 / Gelling Agent ClearFRAC XT B916 / Gelling Agent ClearFRAC XT J590
BA-2
BA-20
BA-40L
BA-40LM
BC-140
BC-140 X2
BE-3S

BE-6
BE-7
BE-9
Bentone A-140
BF-1
BF-7 / BF-7L
BioClear 1000 / Unicide 1000
Bio-Clear 200 / Unicide 2000
Breaker FR
BXL-2, Crosslinker/ Buffer
BXL-STD / XL-300MB
Carbon Dioxide
CL-31
CLA-CHEK LP
CLA-STA XP
Clay Treat PP
Clay Treat TS
Clay Treat-3C
Clayfix II
Clayfix II plus
Cronox 245 ES/ CI-14
CS-250 SI
CS-650 OS, Oxygen Scavenger
CS-Polybreak 210
CS-Polybreak 210 Winterized
EB-4L
Enzyme G-NE
FE-1A
FE-2
FE-2A
FE-5A
Ferchek
Ferchek A
Ferrotrol 300L
Flomax 50
Flomax 70 / VX9173
FLOPAM DR-6000 / DR-6000
FLOPAM DR-7000 / DR-7000
Formic Acid
FR-46
FR-48W

FR-56
FRP-121
FRW-14
GasPerm 1000
GBL-8X / LEB-10X / GB-L / En-breaker
GBW-20C
GBW-30 Breaker
Green-Cide 25G / B244 / B244A
H015 / Hydrochloric Acid 15% H15
HAI-OS Acid Inhibitor
HC-2
High Perm SW-LB
HPH Breaker
HPH foamer
Hydrochloric Acid
Hydrochloric Acid (HCl)
HYG-3
IC 100L
ICA-720 / IC-250
ICA-8 / IC-200
ICI-3240
Inflo-250
InFlo-250W / InFlo-250 Winterized
Iron Check / Iron Chek
Iron Sta IIC / Iron Sta II
Isopropyl Alcohol
J313 / Water Friction-Reducing Agen J313
J534 / Urea Ammonium Nitrate Solution J534
J580 / Water Gelling Agent J580
K-34
K-35
KCI
L058 / Iron Stabilizer L58
L064 / Temporary Clay Stabilizer L64
LGC-35 CBM
LGC-36 UC
LGC-VI UC
Losurf 300M
M003 / Soda Ash M3
MA-844W
Methanol

MO-67
Morflo III
MSA-II
Muriatic Acid 36%
Musol A
N002 / Nitrogen N2
NCL-100
Nitrogen
Para Clear D290 / ParaClean II
Paragon 100 E+
PLURADYNE TDA 6
PSA-2L
PSI-720
PSI-7208
SAS-2
Scalechek LP-55
Scalechek LP-65
Scalehib 100 / Super Scale Inhibitor / Scale Clear SI-112
SGA II
Shale Surf 1000
Shale Surf 1000 Winterized
Sodium Citrate
SP Breaker
STIM-50 / LT-32
Super OW 3
Super Pen 2000
SuperGel 15
U042 / Chelating Agent U42
U066 / Mutual Solvent U66
Unicide 100 / EC6116A
Unifoam
Unigel 5F
UniHibA / SP-43X
UnihibG / S-11
Unislik ST 50 / Stim Lube
Vicon NF
WG-11
WG-17
WG-18
WG-35

WG-36
WLC-6
XL-1
XL-8
XLW-32
Xylene

Table 5-4 Fracturing Additive Products – Partial Composition Disclosure to the Department

Product Name
20 Degree Baume Muriatic Acid
AcTivator / 78-ACTW
AMB-100
B885 / ClearFRAC LT B885 / ClearFRAC LT J551A
B892 / EZEFLO B892 / EZEFLO F110 Surfactant
CL-22UC
Clay Master 5C
Corrosion Inhibitor A261
FAW- 5
FDP-S798-05
FDP-S819-05
FE ACID
FR-48
FRW-16
FRW-18
FRW-25M
GA 8713
GBW-15C
GBW-15L
GW-3LDF
HVG-1, Fast Hydrating Guar Slurry
ICA 400
Inflo-102
J134L / Enzyme Breaker J134L
KCLS-2, KCL Substitute
L065 / Scale Inhibitor L065
LP-65
Magnacide 575 Microbiocide
MSA ACID

Multifunctional Surfactant F105
Nitrogen, Refrigerated Liquid
OptiKleen-WF
Parasperse Cleaner
Product 239
S-150
SandWedge WF
Scalechek SCP-2
SilkWater FR-A
Super Sol 10/20/30
Unislick 30 / Cyanaflo 105L
WC-5584
WCS 5177 Corrosion Scale Inhibitor
WCW219 Combination Inhibitor
WF-12B Foamer
WF-12B Salt Inhibitor Stix
WF-12B SI Foamer/Salt Inhibitor
WF12BH Foamer
WFR-C

Information in sections 5.4.1-3 below was compiled primarily by URS Corporation, under contract to NYSERDA.

5.4.1 Properties of Fracturing Fluids

Additives are used in hydraulic fracturing operations to elicit certain properties and characteristics that would aide and enhance the operation. The desired properties and characteristics include:

- Non-reactive
- Non-flammable
- Minimal residuals
- Minimal potential for scale or corrosion.
- Low entrained solids
- Neutral pH (pH 6.5 – 7.5) for maximum polymer hydration

- Limited formation damage
- Appropriately modify properties of water to carry proppant deep into the shale
- Economical to modify fluid properties
- Minimal environmental effects

5.4.2 Classes of Additives

Table 5.5 lists the types, purposes and examples of additives that have been proposed to date for use in hydraulic fracturing of gas wells in New York State.

Table 5-5 - Types and Purposes of Additives Proposed for Use in New York State

Additive Type	Description of Purpose	Examples of Chemicals[26]
Proppant	"Props" open fractures and allows gas / fluids to flow more freely to the well bore.	Sand [Sintered bauxite; zirconium oxide; ceramic beads]
Acid	Cleans up perforation intervals of cement and drilling mud prior to fracturing fluid injection, and provides accessible path to formation.	Hydrochloric acid (HCl, 3% to 28%)
Breaker	Reduces the viscosity of the fluid in order to release proppant into fractures and enhance the recovery of the fracturing fluid.	Peroxydisulfates
Bactericide / Biocide	Inhibits growth of organisms that could produce gases (particularly hydrogen sulfide) that could contaminate methane gas. Also prevents the growth of bacteria which can reduce the ability of the fluid to carry proppant into the fractures.	Gluteraldehyde; 2-Bromo-2-nitro-1,2-propanediol
Clay Stabilizer / Control	Prevents swelling and migration of formation clays which could block pore spaces thereby reducing permeability.	Salts (e.g., tetramethyl ammonium chloride) [Potassium chloride (KCl)]
Corrosion Inhibitor	Reduces rust formation on steel tubing, well casings, tools, and tanks (used only in fracturing fluids that contain acid).	Methanol
Crosslinker	The fluid viscosity is increased using phosphate esters combined with metals. The metals are referred to as crosslinking agents. The increased fracturing fluid viscosity allows	Potassium hydroxide

[26] Chemicals in brackets [ ] have not been proposed for use in the State of New York to date, but are known to be used in other states or shale formations.

Additive Type	Description of Purpose	Examples of Chemicals[26]
	the fluid to carry more proppant into the fractures.	
Friction Reducer	Allows fracture fluids to be injected at optimum rates and pressures by minimizing friction.	Sodium acrylate-acrylamide copolymer; polyacrylamide (PAM)
Gelling Agent	Increases fracturing fluid viscosity, allowing the fluid to carry more proppant into the fractures.	Guar gum
Iron Control	Prevents the precipitation of metal oxides which could plug off the formation.	Citric acid; thioglycolic acid
Scale Inhibitor	Prevents the precipitation of carbonates and sulfates (calcium carbonate, calcium sulfate, barium sulfate) which could plug off the formation.	Ammonium chloride; ethylene glycol; polyacrylate
Surfactant	Reduces fracturing fluid surface tension thereby aiding fluid recovery.	Methanol; isopropanol

5.4.3 Composition of Fracturing Fluids

The composition of the fracturing fluid used may vary from one geologic basin or formation to another in order to meet the specific needs of each operation; but the range of additive types available for potential use remains the same. There are a number of different chemical compositions for each additive type; however, only one product of each type is typically utilized in any given gas well. The selection may be driven by the formation and potential interactions between additives. Additionally not all additive types will be utilized in every fracturing job.

A sample composition by weight of fracture fluid is provided in Figure 5.3; this composition is based on data from the Fayetteville Shale.[27] Based on this data, approximately 90 percent of the fracture fluid is water; another approximately 9 percent is proppant (see Photo 5.17); the remainder, typically less than 0.5 percent consists of chemical additives listed above.

[27] Similar to the Marcellus Shale, the Fayetteville Shale is a marine shale rich in unoxidized carbon (i.e. a black shale). The two shales are at similar depths, and vertical and horizontal wells have been drilled/fractured at both shales.

Photo 5.17 - Sand used in hydraulic fracturing operation in Bradford County, PA.

Barnett Shale is considered to be the first instance of extensive high-volume hydraulic fracture technology use; the technology has since been applied in other areas such as the Fayetteville Shale and the Haynesville Shale. URS notes that data collected from applications to drill Marcellus Shale wells in New York indicate that the typical fracture fluid composition for operations in the Marcellus Shale is similar to the provided composition in the Fayetteville Shale.

Even though no horizontal wells have been drilled in the Marcellus Shale in New York, applications filed to date indicate that it is realistic to expect that the composition of fracture fluids used in the Marcellus Shale would be similar from one operation to the next. One potential exception is that additional data provided separately to the Department indicates that biocides have comprised up to 0.03% of fracturing fluid instead of 0.001% as noted in Figure 5.3.

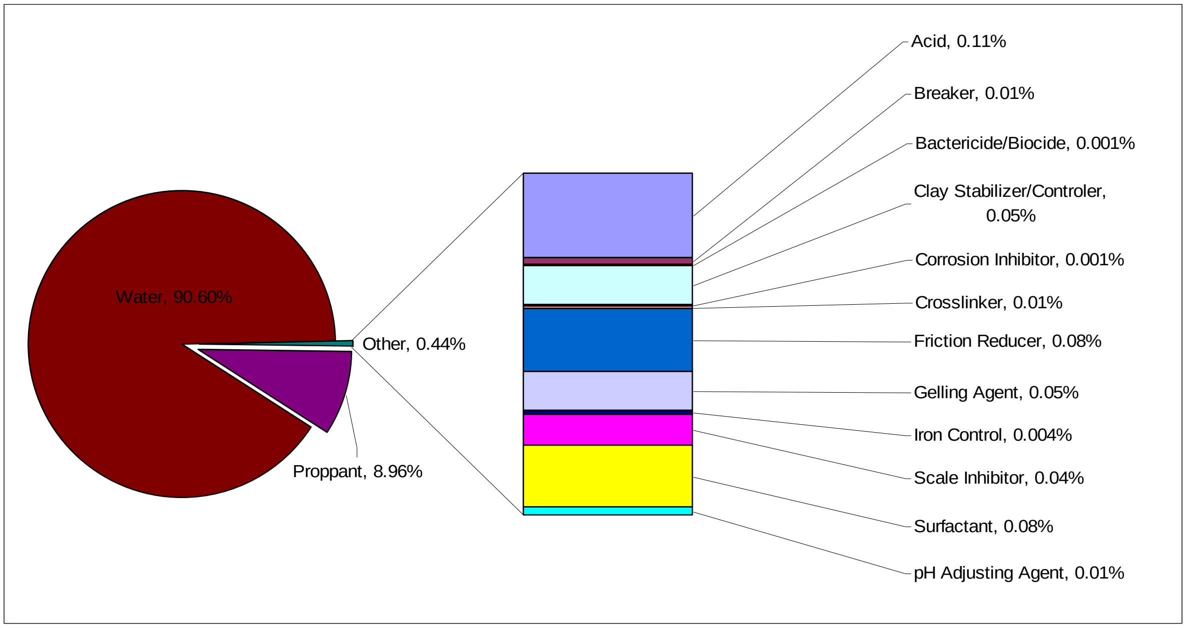

Figure 5-3 - Sample Fracture Fluid Composition by Weight

Each product within the twelve classes of additives may be made up of one or more chemical constituents. Table 5.6 is a list of chemical constituents and their CAS numbers, that have been extracted from complete product chemical compositional information and Material Safety Data Sheets submitted to the NYSDEC for nearly 200 products used or proposed for use in hydraulic fracturing operations in the Marcellus Shale area of New York. It is important to note that several manufacturers and suppliers provide similar chemicals (i.e. chemicals that would serve the same purpose) for any class of additive, and that not all types of additives are used in a single well. Table 5.6 represents constituents of all hydraulic-fracturing-related chemicals submitted to NYSDEC to date for potential use at shale wells in the State, only a handful of which would be utilized in a single well.

Data provided to NYSDEC to date indicates similar fracturing fluid compositions for vertically and horizontally drilled wells.

Table 5-6 - Chemical Constituents in Additives/Chemicals[28,29]

CAS Number[30]	Chemical Constituent
2634-33-5	1,2 Benzisothiazolin-2-one / 1,2-benzisothiazolin-3-one
95-63-6	1,2,4 trimethylbenzene
123-91-1	1,4 Dioxane
3452-07-1	1-eicosene
629-73-2	1-hexadecene
112-88-9	1-octadecene
1120-36-1	1-tetradecene
10222-01-2	2,2 Dibromo-3-nitrilopropionamide
27776-21-2	2,2'-azobis-{2-(imidazlin-2-yl)propane}-dihydrochloride
73003-80-2	2,2-Dobromomalonamide
15214-89-8	2-Acrylamido-2-methylpropanesulphonic acid sodium salt polymer
46830-22-2	2-acryloyloxyethyl(benzyl)dimethylammonium chloride
52-51-7	2-Bromo-2-nitro-1,3-propanediol
111-76-2	2-Butoxy ethanol
1113-55-9	2-Dibromo-3-Nitriloprionamide (2-Monobromo-3-nitriilopropionamide)
104-76-7	2-Ethyl Hexanol
67-63-0	2-Propanol / Isopropyl Alcohol / Isopropanol / Propan-2-ol
26062-79-3	2-Propen-1-aminium, N,N-dimethyl-N-2-propenyl-chloride, homopolymer
9003-03-6	2-propenoic acid, homopolymer, ammonium salt
25987-30-8	2-Propenoic acid, polymer with 2 p-propenamide, sodium salt / Copolymer of acrylamide and sodium acrylate
71050-62-9	2-Propenoic acid, polymer with sodium phosphinate (1:1)
66019-18-9	2-propenoic acid, telomer with sodium hydrogen sulfite
107-19-7	2-Propyn-1-ol / Progargyl Alcohol
51229-78-8	3,5,7-Triaza-1-azoniatricyclo[3.3.1.13,7]decane, 1-(3-chloro-2-propenyl)-chloride,
115-19-5	3-methyl-1-butyn-3-ol
127087-87-0	4-Nonylphenol Polyethylene Glycol Ether Branched / Nonylphenol ethoxylated / Oxyalkylated Phenol
64-19-7	Acetic acid
68442-62-6	Acetic acid, hydroxy-, reaction products with triethanolamine
108-24-7	Acetic Anhydride
67-64-1	Acetone
79-06-1	Acrylamide

[28] Table 5.6 is a list of chemical constituents and their CAS numbers that have been extracted from complete chemical compositions and Material Safety Data Sheets submitted to the NYSDEC.

[29] These are the chemical constituents of all chemical additives proposed to be used in New York for hydraulic fracturing operations at shale wells. Only a few chemicals will be used in a single well; the list of chemical constituents used in an individual well will be correspondingly smaller.

[30] Chemical Abstracts Service (CAS) is a division of the American Chemical Society. CAS assigns unique numerical identifiers to every chemical described in the literature. The intention is to make database searches more convenient, as chemicals often have many names. Almost all molecule databases today allow searching by CAS number.

CAS Number[30]	Chemical Constituent
38193-60-1	Acrylamide - sodium 2-acrylamido-2-methylpropane sulfonate copolymer
25085-02-3	Acrylamide - Sodium Acrylate Copolymer or Anionic Polyacrylamide
69418-26-4	Acrylamide polymer with N,N,N-trimethyl-2[1-oxo-2-propenyl]oxy Ethanaminium chloride
15085-02-3	Acrylamide-sodium acrylate copolymer
68551-12-2	Alcohols, C12-C16, Ethoxylated (a.k.a. Ethoxylated alcohol)
64742-47-8	Aliphatic Hydrocarbon / Hydrotreated light distillate / Petroleum Distillates / Isoparaffinic Solvent / Paraffin Solvent / Napthenic Solvent
64743-02-8	Alkenes
68439-57-6	Alkyl (C14-C16) olefin sulfonate, sodium salt
9016-45-9	Alkylphenol ethoxylate surfactants
1327-41-9	Aluminum chloride
73138-27-9	Amines, C12-14-tert-alkyl, ethoxylated
71011-04-6	Amines, Ditallow alkyl, ethoxylated
68551-33-7	Amines, tallow alkyl, ethoxylated, acetates
1336-21-6	Ammonia
631-61-8	Ammonium acetate
68037-05-8	Ammonium Alcohol Ether Sulfate
7783-20-2	Ammonium bisulfate
10192-30-0	Ammonium Bisulphite
12125-02-9	Ammonium Chloride
7632-50-0	Ammonium citrate
37475-88-0	Ammonium Cumene Sulfonate
1341-49-7	Ammonium hydrogen-difluoride
6484-52-2	Ammonium nitrate
7727-54-0	Ammonium Persulfate / Diammonium peroxidisulphate
1762-95-4	Ammonium Thiocyanate
7664-41-7	Aqueous ammonia
121888-68-4	Bentonite, benzyl(hydrogenated tallow alkyl) dimethylammonium stearate complex / organophilic clay
71-43-2	Benzene
119345-04-9	Benzene, 1,1'-oxybis, tetratpropylene derivatives, sulfonated, sodium salts
74153-51-8	Benzenemethanaminium, N,N-dimethyl-N-[2-[(1-oxo-2-propenyl)oxy]ethyl]-, chloride, polymer with 2-propenamide
10043-35-3	Boric acid
1303-86-2	Boric oxide / Boric Anhydride
71-36-3	Butan-1-ol
68002-97-1	C10 - C16 Ethoxylated Alcohol
68131-39-5	C12-15 Alcohol, Ethoxylated
10043-52-4	Calcium chloride
124-38-9	Carbon Dioxide
68130-15-4	Carboxymethylhydroxypropyl guar
9012-54-8	Cellulase / Hemicellulase Enzyme
9004-34-6	Cellulose
10049-04-4	Chlorine Dioxide
77-92-9	Citric Acid

CAS Number[30]	Chemical Constituent
94266-47-4	Citrus Terpenes
61789-40-0	Cocamidopropyl Betaine
68155-09-9	Cocamidopropylamine Oxide
68424-94-2	Coco-betaine
7758-98-7	Copper (II) Sulfate
31726-34-8	Crissanol A-55
14808-60-7	Crystalline Silica (Quartz)
7447-39-4	Cupric chloride dihydrate
1120-24-7	Decyldimethyl Amine
2605-79-0	Decyl-dimethyl Amine Oxide
3252-43-5	Dibromoacetonitrile
25340-17-4	Diethylbenzene
111-46-6	Diethylene Glycol
22042-96-2	Diethylenetriamine penta (methylenephonic acid) sodium salt
28757-00-8	Diisopropyl naphthalenesulfonic acid
68607-28-3	Dimethylcocoamine, bis(chloroethyl) ether, diquaternary ammonium salt
7398-69-8	Dimethyldiallylammonium chloride
25265-71-8	Dipropylene glycol
139-33-3	Disodium Ethylene Diamine Tetra Acetate
5989-27-5	D-Limonene
123-01-3	Dodecylbenzene
27176-87-0	Dodecylbenzene sulfonic acid
42504-46-1	Dodecylbenzenesulfonate isopropanolamine
50-70-4	D-Sorbitol / Sorbitol
37288-54-3	Endo-1,4-beta-mannanase, or Hemicellulase
149879-98-1	Erucic Amidopropyl Dimethyl Betaine
89-65-6	Erythorbic acid, anhydrous
54076-97-0	Ethanaminium, N,N,N-trimethyl-2-[(1-oxo-2-propenyl)oxy]-, chloride, homopolymer
107-21-1	Ethane-1,2-diol / Ethylene Glycol
9002-93-1	Ethoxylated 4-tert-octylphenol
68439-50-9	Ethoxylated alcohol
126950-60-5	Ethoxylated alcohol
67254-71-1	Ethoxylated alcohol (C10-12)
68951-67-7	Ethoxylated alcohol (C14-15)
68439-46-3	Ethoxylated alcohol (C9-11)
66455-15-0	Ethoxylated Alcohols
84133-50-6	Ethoxylated Alcohols (C12-14 Secondary)
68439-51-0	Ethoxylated Alcohols (C12-14)
78330-21-9	Ethoxylated branch alcohol
34398-01-1	Ethoxylated C11 alcohol
61791-12-6	Ethoxylated Castor Oil
61791-29-5	Ethoxylated fatty acid, coco
61791-08-0	Ethoxylated fatty acid, coco, reaction product with ethanolamine
68439-45-2	Ethoxylated hexanol

CAS Number[30]	Chemical Constituent
9036-19-5	Ethoxylated octylphenol
9005-67-8	Ethoxylated Sorbitan Monostearate
9004-70-3	Ethoxylated Sorbitan Trioleate
64-17-5	Ethyl alcohol / ethanol
100-41-4	Ethyl Benzene
97-64-3	Ethyl Lactate
9003-11-6	Ethylene Glycol-Propylene Glycol Copolymer (Oxirane, methyl-, polymer with oxirane)
75-21-8	Ethylene oxide
5877-42-9	Ethyloctynol
68526-86-3	Exxal 13
61790-12-3	Fatty Acids
68188-40-9	Fatty acids, tall oil reaction products w/ acetophenone, formaldehyde & thiourea
9043-30-5	Fatty alcohol polyglycol ether surfactant
7705-08-0	Ferric chloride
7782-63-0	Ferrous sulfate, heptahydrate
50-00-0	Formaldehyde
29316-47-0	Formaldehyde polymer with 4,1,1-dimethylethyl phenolmethyl oxirane
153795-76-7	Formaldehyde, polymers with branched 4-nonylphenol, ethylene oxide and propylene oxide
75-12-7	Formamide
64-18-6	Formic acid
110-17-8	Fumaric acid
65997-17-3	Glassy calcium magnesium phosphate
111-30-8	Glutaraldehyde
56-81-5	Glycerol / glycerine
9000-30-0	Guar Gum
9000-30-01	Guar Gum
64742-94-5	Heavy aromatic petroleum naphtha
9025-56-3	Hemicellulase
7647-01-0	Hydrochloric Acid / Hydrogen Chloride / muriatic acid
7722-84-1	Hydrogen Peroxide
79-14-1	Hydroxy acetic acid
35249-89-9	Hydroxyacetic acid ammonium salt
9004-62-0	Hydroxyethyl cellulose
5470-11-1	Hydroxylamine hydrochloride
39421-75-5	Hydroxypropyl guar
35674-56-7	Isomeric Aromatic Ammonium Salt
64742-88-7	Isoparaffinic Petroleum Hydrocarbons, Synthetic
64-63-0	Isopropanol
98-82-8	Isopropylbenzene (cumene)
68909-80-8	Isoquinoline, reaction products with benzyl chloride and quinoline
8008-20-6	Kerosene
64742-81-0	Kerosine, hydrodesulfurized

CAS Number[30]	Chemical Constituent
63-42-3	Lactose
64742-95-6	Light aromatic solvent naphtha
1120-21-4	Light Paraffin Oil
14807-96-6	Magnesium Silicate Hydrate (Talc)
1184-78-7	methanamine, N,N-dimethyl-, N-oxide
67-56-1	Methanol
68891-11-2	Methyloxirane polymer with oxirane, mono (nonylphenol) ether, branched
8052-41-3	Mineral spirits / Stoddard Solvent
141-43-5	Monoethanolamine
44992-01-0	N,N,N-trimethyl-2[1-oxo-2-propenyl]oxy Ethanaminium chloride
64742-48-9	Naphtha (petroleum), hydrotreated heavy
91-20-3	Naphthalene
38640-62-9	Naphthalene bis(1-methylethyl)
93-18-5	Naphthalene, 2-ethoxy-
68909-18-2	N-benzyl-alkyl-pyridinium chloride
68139-30-0	N-Cocoamidopropyl-N,N-dimethyl-N-2-hydroxypropylsulfobetaine
7727-37-9	Nitrogen, Liquid form
68412-54-4	Nonylphenol Polyethoxylate
121888-66-2	Organophilic Clays
64742-65-0	Petroleum Base Oil
64741-68-0	Petroleum naphtha
70714-66-8	Phosphonic acid, [[(phosphonomethyl)imino]bis[2,1-ethanediylnitrilobis(methylene)]]tetrakis-, ammonium salt
8000-41-7	Pine Oil
60828-78-6	Poly(oxy-1,2-ethanediyl), a-[3,5-dimethyl-1-(2-methylpropyl)hexyl]-w-hydroxy-
25322-68-3	Poly(oxy-1,2-ethanediyl), a-hydro-w-hydroxy / Polyethylene Glycol
24938-91-8	Poly(oxy-1,2-ethanediyl), α-tridecyl-ω-hydroxy-
51838-31-4	Polyepichlorohydrin, trimethylamine quaternized
56449-46-8	Polyethlene glycol oleate ester
62649-23-4	Polymer with 2-propenoic acid and sodium 2-propenoate
9005-65-6	Polyoxyethylene Sorbitan Monooleate
61791-26-2	Polyoxylated fatty amine salt
127-08-2	Potassium acetate
12712-38-8	Potassium borate
1332-77-0	Potassium borate
20786-60-1	Potassium Borate
584-08-7	Potassium carbonate
7447-40-7	Potassium chloride
590-29-4	Potassium formate
1310-58-3	Potassium Hydroxide
13709-94-9	Potassium metaborate
24634-61-5	Potassium Sorbate
112926-00-8	Precipitated silica / silica gel
57-55-6	Propane-1,2-diol, or Propylene glycol

CAS Number[30]	Chemical Constituent
107-98-2	Propylene glycol monomethyl ether
68953-58-2	Quaternary Ammonium Compounds
62763-89-7	Quinoline,2-methyl-, hydrochloride
15619-48-4	Quinolinium, 1-(phenylmethl),chloride
7631-86-9	Silica, Dissolved
5324-84-5	Sodium 1-octanesulfonate
127-09-3	Sodium acetate
95371-16-7	Sodium Alpha-olefin Sulfonate
532-32-1	Sodium Benzoate
144-55-8	Sodium bicarbonate
7631-90-5	Sodium bisulfate
7647-15-6	Sodium Bromide
497-19-8	Sodium carbonate
7647-14-5	Sodium Chloride
7758-19-2	Sodium chlorite
3926-62-3	Sodium Chloroacetate
68-04-2	Sodium citrate
6381-77-7	Sodium erythorbate / isoascorbic acid, sodium salt
2836-32-0	Sodium Glycolate
1310-73-2	Sodium Hydroxide
7681-52-9	Sodium hypochlorite
7775-19-1	Sodium Metaborate .8H_2O
10486-00-7	Sodium perborate tetrahydrate
7775-27-1	Sodium persulphate
9003-04-7	Sodium polyacrylate
7757-82-6	Sodium sulfate
1303-96-4	Sodium tetraborate decahydrate
7772-98-7	Sodium Thiosulfate
1338-43-8	Sorbitan Monooleate
57-50-1	Sucrose
5329-14-6	Sulfamic acid
112945-52-5	Syntthetic Amorphous / Pyrogenic Silica / Amorphous Silica
68155-20-4	Tall Oil Fatty Acid Diethanolamine
8052-48-0	Tallow fatty acids sodium salt
72480-70-7	Tar bases, quinoline derivs., benzyl chloride-quaternized
68647-72-3	Terpene and terpenoids
68956-56-9	Terpene hydrocarbon byproducts
533-74-4	Tetrahydro-3,5-dimethyl-2H-1,3,5-thiadiazine-2-thione (a.k.a. Dazomet)
55566-30-8	Tetrakis(hydroxymethyl)phosphonium sulfate (THPS)
75-57-0	Tetramethyl ammonium chloride
64-02-8	Tetrasodium Ethylenediaminetetraacetate
68-11-1	Thioglycolic acid
62-56-6	Thiourea
68527-49-1	Thiourea, polymer with formaldehyde and 1-phenylethanone
108-88-3	Toluene

CAS Number[30]	Chemical Constituent
81741-28-8	Tributyl tetradecyl phosphonium chloride
68299-02-5	Triethanolamine hydroxyacetate
112-27-6	Triethylene Glycol
52624-57-4	Trimethylolpropane, Ethoxylated, Propoxylated
150-38-9	Trisodium Ethylenediaminetetraacetate
5064-31-3	Trisodium Nitrilotriacetate
7601-54-9	Trisodium ortho phosphate
57-13-6	Urea
25038-72-6	Vinylidene Chloride/Methylacrylate Copolymer
7732-18-5	Water
1330-20-7	Xylene

Chemical Constituent
Aliphatic acids
Aliphatic alcohol glycol ether
Alkyl Aryl Polyethoxy Ethanol
Alkylaryl Sulfonate
Aromatic hydrocarbons
Aromatic ketones
Oxyalkylated alkylphenol
Petroleum distillate blend
Polyethoxylated alkanol
Polymeric Hydrocarbons
Salt of amine-carbonyl condensate
Salt of fatty acid/polyamine reaction product
Sugar
Surfactant blend

Chemical constituents are not linked to product names in Table 5.6 because a significant number of product composition and formulas have been justified as trade secrets as defined and provided by Public Officers Law §87.2(d) and the Department's implementing regulation, 6 NYCRR 616.7.

5.4.3.1 Chemical Categories and Health Information

DEC requested assistance from NYSDOH in identifying potential exposure pathways and constituents of concern associated with high-volume hydraulic fracturing for low-permeability gas reservoir development. DEC provided DOH with fracturing additive product constituents based on Material Safety Data Sheets (MSDSs) and product-composition disclosures for hydraulic fracturing additive products that were provided by well-service companies and the chemical supply companies that manufacture the products.

Compound-specific toxicity data are very limited for many chemical additives to fracturing fluids, so chemicals potentially present in fracturing fluids were grouped together into categories according to their chemical structure (or function in the case of microbiocides) in Table 5.7, compiled by NYSDOH. As explained above, any given individual fracturing job will only involve a handful of chemicals and may not include every category of chemicals.

Table 5-7 - Categories based on chemical structure of potential fracturing fluid constituents. Chemicals are grouped in order of ascending CAS Number by category.

Chemical	CAS Number
Amides	
Formamide	75-12-7
acrylamide	79-06-1
Amines	
urea	57-13-6
thiourea	62-56-6
tetramethyl ammonium chloride	75-57-0
monoethanolamine	141-43-5
Decyldimethyl Amine	1120-24-7
methanamine, N,N-dimethyl-, N-oxide	1184-78-7
Decyl-dimethyl Amine Oxide	2605-79-0
dimethyldiallylammonium chloride	7398-69-8
polydimethyl dially ammonium chloride	26062-79-3
dodecylbenzenesulfonate isopropanolamine	42504-46-1
N,N,N-trimethyl-2[1-oxo-2-propenyl]oxy ethanaminium chloride	44992-01-0
2-acryloyloxyethyl(benzyl)dimethylammonium chloride	46830-22-2
ethanaminium, N,N,N-trimethyl-2-[(1-oxo-2-propenyl)oxy]-, chloride, homopolymer	54076-97-0
Cocamidopropyl Betaine	61789-40-0
polyoxylated fatty amine salt	61791-26-2
quinoline, 2-methyl, hydrochloride	62763-89-7
N-cocoamidopropyl-N,N-dimethyl-N-2-hydroxypropylsulfobetaine	68139-30-0
tall oil fatty acid diethanolamine	68155-20-4
N-cocoamidopropyl-N,N-dimethyl-N-2-hydroxypropylsulfobetaine	68424-94-2
amines, tallow alkyl, ethoxylated, acetates	68551-33-7

Chemical	CAS Number
quaternary ammonium compounds, bis(hydrogenated tallow alkyl) dimethyl, salts with bentonite	68953-58-2
amines, ditallow alkyl, ethoxylated	71011-04-6
amines, C-12-14-tert-alkyl, ethoxylated	73138-27-9
benzenemethanaminium, N,N-dimethyl-N-[2-[(1-oxo-2-propenyl)oxy]ethyl]-, chloride, polymer with 2-propenamide	74153-51-8
Erucic Amidopropyl Dimethyl Betaine	149879-98-1
Petroleum Distillates	
light paraffin oil	1120-21-4
kerosene	8008-20-6
stoddard solvent	8052-41-3
petroleum naphtha	64741-68-0
<u>Multiple names listed under same CAS#:</u> LVP aliphatic hydrocarbon, hydrotreated light distillate, low odor paraffin solvent, paraffin solvent, paraffinic napthenic solvent, isoparaffinic solvent, distillates (petroleum) hydrotreated light, petroleum light distillate, aliphatic hydrocarbon, petroleum distillates	64742-47-8
naphtha, hydrotreated heavy	64742-48-9
petroleum base oil	64742-65-0
kerosine (petroleum, hydrodesulfurized)	64742-81-0
kerosine (petroleum, hydrodesulfurized)	64742-88-7
<u>Multiple names listed under same CAS#:</u> heavy aromatic petroleum naphtha, light aromatic solvent naphtha	64742-94-5
light aromatic solvent naphtha	64742-95-6
alkenes, C> 10 α-	64743-02-8
Aromatic Hydrocarbons	
benzene	71-43-2
naphthalene	91-20-3
naphthalene, 2-ethoxy	93-18-5
1,2,4-trimethylbenzene	95-63-6
cumene	98-82-8
ethyl benzene	100-41-4
toluene	108-88-3
dodecylbenzene	123-01-3
xylene	1330-20-7

Chemical	CAS Number
diethylbenzene	25340-17-4
naphthalene bis(1-methylethyl)	38640-62-9
Alcohols	
sorbitol (or) D-sorbitol	50-70-4
Glycerol	56-81-5
propylene glycol	57-55-6
ethanol	64-17-5
isopropyl alcohol	67-63-0
methanol	67-56-1
isopropyl alcohol	67-63-0
butanol	71-36-3
2-ethyl-1-hexanol	104-76-7
propargyl alcohol	107-19-7
ethylene glycol	107-21-1
Diethylene Glycol	111-46-6
3-methyl-1-butyn-3-ol	115-19-5
Ethyloctynol	5877-42-9
Glycol Ethers & Ethoxylated Alcohols	
propylene glycol monomethyl ether	107-98-2
ethylene glycol monobutyl ether	111-76-2
triethylene glycol	112-27-6
oxylated 4-tert-octylphenol	9002-93-1
ethoxylated sorbitan trioleate	9005-70-3
Polysorbate 80	9005-65-6
ethoxylated sorbitan monostearate	9005-67-8
Polyethylene glycol-(phenol) ethers	9016-45-9
Polyethylene glycol-(phenol) ethers	9036-19-5
fatty alcohol polyglycol ether surfactant	9043-30-5
Poly(oxy-1,2-ethanediyl), α-tridecyl-ω-hydroxy-	24938-91-8
Dipropylene glycol	25265-71-8
Nonylphenol Ethoxylate	26027-38-3
crissanol A-55	31726-34-8
Polyethylene glycol-(alcohol) ethers	34398-01-1
Trimethylolpropane, Ethoxylated, Propoxylated	52624-57-4
Polyethylene glycol-(alcohol) ethers	60828-78-6
Ethoxylated castor oil [PEG-10 Castor oil]	61791-12-6

Chemical	CAS Number
ethoxylated alcohols	66455-15-0
ethoxylated alcohol	67254-71-1
Ethoxylated alcohols (9 – 16 carbon atoms)	68002-97-1
ammonium alcohol ether sulfate	68037-05-8
Polyethylene glycol-(alcohol) ethers	68131-39-5
Polyethylene glycol-(phenol) ethers	68412-54-4
ethoxylated hexanol	68439-45-2
Polyethylene glycol-(alcohol) ethers	68439-46-3
Ethoxylated alcohols (9 – 16 carbon atoms)	68439-50-9
C12-C14 ethoxylated alcohols	68439-51-0
Exxal 13	68526-86-3
Ethoxylated alcohols (9 – 16 carbon atoms)	68551-12-2
alcohols, C-14-15, ethoxylated	68951-67-7
Ethoxylated Branched C11-14, C-13-rich Alcohols	78330-21-9
Ethoxylated alcohols (9 – 16 carbon atoms)	84133-5-6
alcohol ethoxylated	126950-60-5
Polyethylene glycol-(phenol) ethers	127087-87-0
Microbiocides	
bronopol	52-51-7
glutaraldehyde	111-30-8
2-monobromo-3-nitrilopropionamide	1113-55-9
1,2-benzisothiazolin-3-one	2634-33-5
dibromoacetonitrile	3252-43-5
dazomet	533-74-4
Hydrogen Peroxide	7722-84-1
2,2-dibromo-3-nitrilopropionamide	10222-01-2
tetrakis	55566-30-8
2,2-dibromo-malonamide	73003-80-2
Organic Acids and Related Chemicals	
tetrasodium EDTA	64-02-8
formic acid	64-18-6
acetic acid	64-19-7
sodium citrate	68-04-2
thioglycolic acid	68-11-1
hydroxyacetic acid	79-14-1
erythorbic acid, anhydrous	89-65-6

Chemical	CAS Number
ethyl lactate	97-64-3
acetic anhydride	108-24-7
fumaric acid	110-17-8
potassium acetate	127-08-2
sodium acetate	127-09-3
Disodium Ethylene Diamine Tetra Acetate	139-33-3
Trisodium Ethylenediamine tetraacetate	150-38-9
sodium benzoate	532-32-1
potassium formate	590-29-4
ammonium acetate	631-61-8
Sodium Glycolate	2836-32-0
Sodium Chloroacetate	3926-62-3
trisodium nitrilotriacetate	5064-31-3
sodium 1-octanesulfonate	5324-84-5
Sodium Erythorbate	6381-77-7
ammonium citrate	7632-50-0
tallow fatty acids sodium salt	8052-48-0
quinolinium, 1-(phenylmethyl), chloride	15619-48-4
diethylenetriamine penta (methylenephonic acid) sodium salt	22042-96-2
potassium sorbate	24634-61-5
dodecylbenzene sulfonic acid	27176-87-0
diisopropyl naphthalenesulfonic acid	28757-00-8
hydroxyacetic acid ammonium salt	35249-89-9
isomeric aromatic ammonium salt	35674-56-7
ammonium cumene sulfonate	37475-88-0
Fatty Acids	61790-12-3
fatty acid, coco, ethoxylated	61791-29-5
2-propenoic acid, telomer with sodium hydrogen sulfite	66019-18-9
carboxymethylhydroxypropyl guar	68130-15-4
fatty acids, tall oil reaction products w/ acetophenone, formaldehyde & thiourea	68188-40-9
triethanolamine hydroxyacetate	68299-02-5
alkyl (C14-C16) olefin sulfonate, sodium salt	68439-57-6
triethanolamine hydroxyacetate	68442-62-6
N-benzyl-alkyl-pyridinium chloride	68909-18-2
phosphonic acid, [[(phosphonomethyl)imino]bis[2,1-ethanediylnitrilobis (methylene)]]tetrakis-ammonium salt	70714-66-8
tributyl tetradecyl phosphonium chloride	81741-28-8
sodium alpha-olefin sulfonate	95371-16-7

Chemical	CAS Number
benzene, 1,1'-oxybis, tetratpropylene derivatives, sulfonated, sodium salts	119345-04-9
Polymers	
guar gum	9000-30-0
guar gum	9000-30-01
2-propenoic acid, homopolymer, ammonium salt	9003-03-6
low mol wt polyacrylate	9003-04-7
Low Mol. Wt. Polyacrylate	9003-04-7
Multiple names listed under same CAS#: oxirane, methyl-, polymer with oxirane, Ethylene Glycol-Propylene Glycol Copolymer	9003-11-6
cellulose	9004-34-6
hydroxyethyl cellulose	9004-62-0
cellulase/hemicellulase enzyme	9012-54-8
hemicellulase	9025-56-3
acrylamide-sodium acrylate copolymer	25085-02-3
Vinylidene Chloride/Methylacrylate Copolymer	25038-72-6
polyethylene glycol	25322-68-3
copolymer of acrylamide and sodium acrylate	25987-30-8
formaldehyde polymer with 4,1,1-dimethylethyl phenolmethyl oxirane	29316-47-0
hemicellulase	37288-54-3
acrylamide - sodium 2-acrylamido-2-methylpropane sulfonate copolymer	38193-60-1
oxiranemthanaminium, N,N,N-trimethyl-, chloride, homopolymer (aka: polyepichlorohydrin, trimethylamine quaternized)	51838-31-4
polyethlene glycol oleate ester	56449-46-8
polymer with 2-propenoic acid and sodium 2-propenoate	62649-23-4
modified thiourea polymer	68527-49-1
methyloxirane polymer with oxirane, mono (nonylphenol) ether, branched	68891-11-2
acrylamide polymer with N,N,N-trimethyl-2[1-oxo-2-propenyl]oxy ethanaminium chloride	69418-26-4
2-propenoic acid, polymer with sodium phosphinate (1:1)	71050-62-9
formaldehyde, polymers with branched 4-nonylphenol, ethylene oxide and propylene oxide	153795-76-7
Minerals, Metals and other Inorganics	
carbon dioxide	124-38-9
sodium bicarbonate	144-55-8
Sodium Carbonate	497-19-8
Potassium Carbonate	584-08-7
Boric Anhydride (a.k.a. Boric Oxide)	1303-86-2
sodium tetraborate decahydrate	1303-96-4
Potassium Hydroxide	1310-58-3

Chemical	CAS Number
sodium hydroxide	1310-73-2
aluminum chloride, basic	1327-41-9
sodium tetraborate decahydrate	1332-77-0
aqua ammonia 29.4%	1336-21-6
ammonium hydrogen-difluoride	1341-49-7
ammonium thiocyanate	1762-95-4
sulfamic acid	5329-14-6
hydroxylamine hydrochloride	5470-11-1
ammonium nitrate	6484-52-2
cupric chloride dihydrate	7447-39-4
potassium chloride	7447-40-7
Trisodium ortho phosphate	7601-54-9
Non-Crystaline Silica	7631-86-9
sodium bisulfate	7631-90-5
hydrochloric acid	7647-01-0
sodium chloride	7647-14-5
sodium bromide	7647-15-6
aqueous ammonia	7664-41-7
sodium hypochlorite	7681-52-9
ferric chloride	7705-08-0
nitrogen	7727-37-9
ammonium persulfate	7727-54-0
water	7732-18-5
sodium sulfate	7757-82-6
sodium chlorite	7758-19-2
sodium thousulfate	7772-98-7
Sodium Metaborate.8H2O	7775-19-01
Sodium Persulphate	7775-27-1
ferrous sulfate, heptahydrate	7782-63-0
ammonium bisulfate	7783-20-2
boric acid	10043-35-3
Calcium Chloride	10043-52-4
Chlorine Dioxide	10049-04-4
ammonium bisulphite	10192-30-0
sodium perborate tetrahydrate	10486-00-7
ammonium chloride	12125-02-9
potassium borate	12714-38-8
potassium metaborate	13709-94-9

Chemical	CAS Number
Magnesium Silicate Hydrate (Talc)	14807-96-6
crystalline silica (quartz)	14808-60-7
glassy calcium magnesium phosphate	65997-17-3
silica gel	112926-00-8
synthetic amorphous, pyrogenic silica	112945-52-5
synthetic amorphous, pyrogenic silica	121888-66-2
Miscellaneous	
formaldehyde	50-00-0
Sucrose	57-50-1
lactose	63-42-3
acetone	67-64-1
ethylene oxide	75-21-8
1-octadecene	112-88-9
1,4-dioxane	123-91-1
1-hexadecene	629-73-2
1-tetradecene	1120-36-1
sorbitan monooleate	1338-43-8
1-eicosene	3452-07-1
D-Limonene	5989-27-5
Pine Oil	8000-41-7
2,2'-azobis-{2-(imidazlin-2-yl)propane}-dihydrochloride	27776-21-2
3,5,7-triaza-1-azoniatricyclo[3.3.1.13,7]decane, 1-(3-chloro-2-propenyl)-chloride	51229-78-8
alkenes	64743-02-8
Cocamidopropyl Oxide	68155-09-9
terpene and terpenoids	68647-72-3
terpene hydrocarbon byproducts	68956-56-9
tar bases, quinoline derivs., benzyl chloride-quaternized	72780-70-7
citrus terpenes	94266-47-4
organophilic clays	121888-68-4
Listed without CAS Number[31]	
belongs with amines	
proprietary quaternary ammonium compounds	NA
quaternary ammonium compound	NA

[31] Constituents listed without CAS #'s were tentatively placed in chemical categories based on the name listed on the MSDS or within confidential product composition disclosures. Many of the constituents reported without CAS #s, are mixtures which require further disclosure to DEC.

Chemical	CAS Number
triethanolamine (tea) 85%, drum	NA
Quaternary amine	NA
Fatty amidoalkyl betaine	NA
belongs with petroleum distillates	
petroleum distillate blend	NA
belongs with aromatic hydrocarbons	
aromatic hydrocarbon	NA
aromatic ketones	NA
belongs with glycol ethers and ethoxylated alcohols	
Acetylenic Alcohol	NA
Aliphatic Alcohols, ethoxylated	NA
Aliphatic Alcohol glycol ether	NA
Ethoxylated alcohol linear	NA
Ethoxylated alcohols	NA
aliphatic alcohol polyglycol ether	NA
alkyl aryl polyethoxy ethanol	NA
misture of ethoxylated alcohols	NA
nonylphenol ethoxylate	NA
oxyalkylated alkylphenol	NA
polyethoxylated alkanol	NA
Oxyalkylated alcohol	NA
belongs with organic acids	
Aliphatic acids derivative	NA
Aliphatic Acids	NA
hydroxy acetic acid	NA
citric acid 50%, base formula	NA
Alkylaryl Sulfonate	NA
belongs with polymers	
hydroxypropyl guar	NA
2-acrylamido-2-methylpropanesulphonic acid sodium salt polymer	NA
belongs with minerals, metals and other inorganics	
precipitated silica	NA
sodium hydroxide	NA
belongs with miscellaneous	
epa inert ingredient	NA
non-hazardous ingredients	NA
proprietary surfactant	NA
salt of fatty acid/polyamine reaction product	NA

Chemical	CAS Number
salt of amine-carbonyl condensate	NA
surfactant blend	NA
sugar	NA
polymeric hydrocarbon mixture	NA

Although exposure to fracturing additives would require a failure of operational controls such as an accident, a spill or other non-routine incident, the health concerns noted by NYSDOH for each chemical category are discussed below. The discussion is based on available qualitative hazard information for chemicals from each category. Qualitative descriptions of potential health concerns discussed below generally apply to all exposure routes (i.e., ingestion, inhalation or skin contact) unless a specific exposure route is mentioned. For most chemical categories, health information is available for only some of the chemicals in the category. More specific assessment of health risks associated with a contamination event would entail an analysis based on the specific additives being used and site-specific information about exposure pathways and environmental contaminant levels. Potential human health risks of a specific event would be assessed by comparison of case-specific exposure data with existing drinking standards or ambient air guidelines.[32] If needed, other chemical-specific health comparison values would be developed, based on a case-specific review of toxicity literature for the chemicals involved. A case-specific assessment would include information on how potential health effects might differ (both qualitatively and quantitatively) depending on the route of exposure.

Petroleum Distillate Products

Petroleum-based constituents are included in some fracturing fluid additive products. They are listed in MSDSs as various petroleum distillate fractions including kerosene, petroleum naphtha, aliphatic hydrocarbon, petroleum base oil, heavy aromatic petroleum naphtha, mineral spirits, hydrotreated light petroleum distillates, stoddard solvent or aromatic hydrocarbon. These can be found in a variety of additive products including corrosion inhibitors, friction reducers and solvents. Petroleum distillate products are mixtures that vary in their composition, but they have similar adverse health effects. Accidental ingestion that results in exposure to large amounts of

[32] 10 NYCRR Part 5: Drinking Water Supplies; Subpart 5-1: Public Water Systems, Maximum Contaminant Levels;
NYS DEC Policy DAR-1: Guidelines for the Control of Toxic Ambient Air Contaminants

petroleum distillates is associated with adverse effects on the gastrointestinal system and central nervous system. Skin contact with kerosene for short periods can cause skin irritation, blistering or peeling. Breathing petroleum distillate vapors can adversely affect the central nervous system.

Aromatic Hydrocarbons

Some fracturing additive products contain specific aromatic hydrocarbon compounds that can also occur in petroleum distillates (benzene, toluene, ethylbenzene and xylene or BTEX; naphthalene and related derivatives, trimethylbenzene, diethylbenzene, dodecylbenzene, cumene). BTEX compounds are associated with adverse effects on the nervous system, liver, kidneys and blood-cell-forming tissues. Benzene has been associated with an increased risk of leukemia in industrial workers who breathed elevated levels of the chemical over long periods of time in workplace air. Exposure to high levels of xylene has damaged the unborn offspring of laboratory animals exposed during pregnancy. Naphthalene is associated with adverse effects on red blood cells when people consumed naphthalene mothballs or when infants wore cloth diapers stored in mothballs. Laboratory animals breathing naphthalene vapors for their lifetimes had damage to their respiratory tracts and increased risk of nasal and lung tumors.

Glycols

Glycols occur in several fracturing fluid additives including crosslinkers, breakers, clay and iron controllers, friction reducers and scale inhibitors. Propylene glycol has low inherent toxicity and is used as an additive in food, cosmetic and drug products. High exposure levels of ethylene glycol adversely affect the kidneys and reproduction in laboratory animals.

Glycol Ethers

Glycol ethers and related ethoxylated alcohols and phenols are present in fracturing fluid additives, including corrosion inhibitors, surfactants and friction reducers. Some glycol ethers (e.g., monomethoxyethanol, monoethoxyethanol, propylene glycol monomethyl ether, ethylene glycol monobutyl ether) can affect the male reproductive system and red blood cell formation in laboratory animals at high exposure levels.

Alcohols

Alcohols are present in some fracturing fluid additive products, including corrosion inhibitors, foaming agents, iron and scale inhibitors and surfactants. Exposure to high levels of some alcohols (e.g., ethanol, methanol) affect the central nervous system.

Amides

Acrylamide is used in some fracturing fluid additives to create polymers during the stimulation process. These polymers are part of some friction reducers and scale inhibitors. Although the reacted polymers that form during fracturing are of low inherent toxicity, unreacted acrylamide may be present in the fracturing fluid, or breakdown of the polymers could release acrylamide back into the flowback water. High levels of acrylamide damage the nervous system and reproductive system in laboratory animals and also cause cancer in laboratory animals.

Formamide may be used in some corrosion inhibitors products. Ingesting high levels of formamide adversely affects the female reproductive system in laboratory animals.

Amines

Amines are constituents of fracturing fluid products including corrosion inhibitors, cross-linkers, friction reducers, iron and clay controllers and surfactants. Chronic ingestion of mono-, di- or tri-ethanolamine adversely affects the liver and kidneys of laboratory animals.

Some quaternary ammonium compounds, such as dimethyldiallyl ammonium chloride, can react with chemicals used in some systems for drinking water disinfection to form nitrosamines. Nitrosamines cause genetic damage and cancer when ingested by laboratory animals.

Organic Acids, Salts and Related Chemicals

Organic acids and related chemicals are constituents of fracturing fluid products including acids, buffers, corrosion and scale inhibitors, friction reducers, iron and clay controllers, solvents and surfactants. Some short-chain organic acids such as formic, acetic and citric acids can be corrosive or irritating to skin and mucous membranes at high concentrations. However, acetic and citric acids are regularly consumed in foods (such as vinegar and citrus fruits) where they occur naturally at lower levels that are not harmful.

Some foaming agents and surfactant products contain organic chemicals included in this category that contain a sulfonic acid group (sulfonates). Exposure to elevated levels of sulfonates is irritating to the skin and mucous membranes.

Microbiocides

Microbiocides are antimicrobial pesticide products intended to inhibit the growth of various types of bacteria in the well. A variety of different chemicals are used in different microbiocide products that are proposed for Marcellus wells. Toxicity information is limited for several of the microbiocide chemicals. However, for some, high exposure has caused effects in the respiratory and gastrointestinal tracts, the kidneys, the liver and the nervous system in laboratory animals.

Other Constituents

The remaining chemicals listed in MSDSs and confidential product composition disclosures provided to DEC are included in Table 5.7 under the following categories: polymers, miscellaneous chemicals that did not fit another chemical category and product constituents that were not identified by a Chemical Abstract Service (CAS) number. Readily available health effects information is lacking for many of these constituents, but two that are relatively well studied are discussed here. In the event of environmental contamination involving chemicals lacking readily available health effects information, the toxicology literature would have to be researched for chemical-specific toxicity data.

Formaldehyde is listed as a constituent in some corrosion inhibitors, scale inhibitors and surfactants. In most cases, the concentration listed in the product is relatively low (< 1%) and is listed alongside a formaldehyde-based polymer constituent. Formaldehyde is irritating to tissues when it comes into direct contact with them. The most common symptoms include irritation of the skin, eyes, nose, and throat, along with increased tearing. Severe pain, vomiting, coma, and possible death can occur after drinking large amounts of formaldehyde. Several studies of laboratory rats exposed for life to high amounts of formaldehyde in air found that the rats developed nose cancer. Some studies of humans exposed to lower amounts of formaldehyde in workplace air found more cases of cancer of the nose and throat (nasopharyngeal cancer) than expected, but other studies have not found nasopharyngeal cancer in other groups of workers exposed to formaldehyde in air.

1,4-dioxane may be used in some surfactant products. 1,4-Dioxane is irritating to the eyes and nose when vapors are breathed. Exposure to very high levels may cause severe kidney and liver effects and possibly death. Studies in animals have shown that breathing vapors of 1,4-dioxane, swallowing liquid 1,4-dioxane or contaminated drinking water, or having skin contact with liquid 1,4-dioxane affects mainly the liver and kidneys. Laboratory rats and mice that drank water containing 1,4-dioxane during most of their lives developed liver cancer; the rats also developed cancer inside the nose.

Conclusions

The hydraulic fracturing product additives proposed for use in NYS and used for fracturing horizontal Marcellus shale wells in other states contain similar types of chemical constituents as the products that have been used for many years for hydraulic fracturing of traditional vertical wells in NYS. Some of the same products are used in both well types. The total amount of fracturing additives and water used in hydraulic fracturing of horizontal wells is considerably larger than for traditional vertical wells. This suggests the potential environmental consequences of an upset condition could be proportionally larger for horizontal well drilling and fracturing operations. As mentioned earlier, the 1992 GEIS addressed hydraulic fracturing in Chapter 9, and NYSDOH's review did not identify any potential exposure situations associated with horizontal drilling and high-volume hydraulic fracturing that are qualitatively different from those addressed in the GEIS.

5.5 Transport of Hydraulic Fracturing Additives

Fracturing additives are transported in "DOT-approved" trucks or containers. The trucks are typically flat-bed trucks that carry a number of strapped-on plastic totes which contain the liquid additive products. (Totes are further described in Section 5.6.) Liquid products used in smaller quantities are transported in one-gallon sealed jugs carried in the side boxes of the flat-bed. Some liquid constituents, such as hydrochloric acid, are transferred in tank trucks.

Dry additives are transported on flat-beds in 50- or 55-pound bags which are set on pallets containing 40 bags each and shrink-wrapped, or in five-gallon sealed plastic buckets. When smaller quantities of some dry products such as powdered biocides are used, they are contained in a double-bag system and may be transported in the side boxes of the truck that constitutes the blender unit.

Regulations that reference "DOT-approved" trucks or containers that are applicable to the transportation and storage of hazardous frac additives refer to federal (USDOT) regulations for registering and permitting commercial motor carriers and drivers, and established standards for hazardous containers. The United Nations (UN) also has established standards and criteria for containers. New York is one of many states where the state agency (NYSDOT) has adopted the federal regulations for transporting hazardous materials interstate. The NYSDOT has its own requirements for intrastate transportation. [33]

Transporting frac additives that are hazardous is comprehensively regulated under existing regulations. The regulated materials include the hazardous additives and mixtures containing thresholds of hazardous materials. These transported materials are maintained in the USDOT or UN-approved storage containers until the materials are consumed at the drill sites.[34]

5.5.1 USDOT Transportation Regulations[35]

The federal Hazardous Material Transportation Act (HMTA, 1975) and the Hazardous Materials Transportation Uniform Safety Act (HMTUSA, 1990) are the basis for federal hazardous materials transportation law (49 U.S.C.) and give regulatory authority to the Secretary of the USDOT to:

- "Designate material (including an explosive, radioactive, infectious substance, flammable or combustible liquid, solid or gas, toxic, oxidizing, or corrosive material, and compressed gas) or a group or class of material as hazardous when the Secretary determines that transporting the material in commerce in a particular amount and form may pose an unreasonable risk to health and safety or property; and

- "Issue regulations for the safe transportation, including security, of hazardous material in intrastate, interstate, and foreign commerce" (PHMSA, 2009).

[33] Alpha Environmental Consultants, Inc., 2009. *Technical Contributions to the Draft Supplemental Generic Environmental Impact Satement (dSGEIS) for the NYSDEC Oil, Gas and Solution Mining Regulatory Program.*

[34] Ibid.

[35] Ibid.

The Code of Federal Regulations (CFR), Title 49, includes the Hazardous Materials Transportation Regulations, Parts 100 through 199. Federal hazardous materials regulations include:

- Hazardous materials classification (Parts 171 and 173)
- Hazard communication (Part 172)
- Packaging requirements (Parts 173, 178, 179, 180)
- Operational rules (Parts 171, 172, 173, 174, 175, 176, 177)
- Training and security (part 172)
- Registration (Part 171)

The extensive regulations address the potential concerns involved in transporting hazardous fracturing additives, such as Loading and Unloading (Part 177), General Requirements for Shipments and Packaging (Part 173), Specifications for Packaging (Part 178), and Continuing Qualification and Maintenance of Packaging (Part 180).

Regulatory functions are carried out by the following USDOT agencies:

- Pipeline and Hazardous Materials Safety Administration (PHMSA)
- Federal Motor Carrier Safety Administration (FMCSA)
- Federal Aviation Administration (FAA)
- United States Coast Guard (USCG)

Each of these agencies shares in promulgating regulations and enforcing the federal hazmat regulations. State, local, or tribal requirements may only preempt federal hazmat regulations if one of the federal enforcing agencies issues a waiver of preemption based on accepting a regulation that offers an equal or greater level of protection to the public and does not unreasonably burden commerce.

The interstate transportation of hazardous materials for motor carriers is regulated by FMCSA and PHMSA. FMCSA establishes standards for commercial motor vehicles, drivers, and companies, and enforces 49 CFR Parts 350-399. FMCSA's responsibilities include monitoring and enforcing regulatory compliance, with focus on safety and financial responsibility. PHMSA's enforcement activities relate to "the shipment of hazardous materials, fabrication, marking, maintenance, reconditioning, repair or testing of multi-modal containers that are represented, marked, certified, or sold for use in the transportation of hazardous materials." PHMSA's regulatory functions include issuing Hazardous Materials Safety Permits; issuing rules and regulations for safe transportation; issuing, renewing, modifying, and terminating special permits and approvals for specific activities; and receiving, reviewing, and maintaining records, among other duties.

5.5.2 New York State DOT Transportation Regulations[36]

New York State requires all registrants of commercial motor vehicles to obtain a USDOT number. New York has adopted the FMCSA regulations CFR 49, Parts 390, 391, 392, 393, 395, and 396, and the Hazardous Materials Transportation Regulations, Parts 100 through 199, as those regulations apply to interstate highway transportation (NYSDOT, 6/2/09). There are minor exemptions to these federal regulations in NYCRR Title17 Part 820, "New York State Motor Carrier Safety Regulations"; however, the exemptions do not directly relate to the objectives of this review.

The NYS regulations include motor vehicle carriers that operate solely on an intrastate basis. Those carriers and drivers operating in intrastate commerce must comply with 17 NYCRR Part 820, in addition to the applicable requirements and regulations of the NYS Vehicle and Traffic Law and the NYS Department of Motor Vehicles (DMV), including the regulations requiring registration or operating authority for transporting hazardous materials from the USDOT or the NYSDOT Commissioner.

Part 820.8 (Transportation of hazardous materials) states "Every person … engaged in the transportation of hazardous materials within this State shall be subject to the rules and regulations contained in this Part." The regulations require that the material be "properly classed, described, packaged, clearly marked, clearly labeled, and in the condition for shipment…" [820.8(b)]; that the material "is handled and transported in accordance with this

[36] Ibid.

Part" [(820.8(c)]; "require a shipper of hazardous materials to have someone available at all times, 24 hours a day, to answer questions with respect to the material being carried and the hazards involved" [(820.8.(f)]; and provides for immediately reporting to "the fire or police department of the local municipality or to the Division of State Police any incident that occurs during the course of transportation (including loading, unloading and temporary storage) as a direct result of hazardous materials" [820.8 (h)].

Part 820 specifies that "In addition to the requirements of this Part, the Commissioner of Transportation adopts the following sections and parts of Title 49 of the Code of Federal Regulations with the same force and effect… for classification, description, packaging, marking, labeling, preparing, handling and transporting all hazardous materials, and procedures for obtaining relief from the requirements, all of the standards, requirements and procedures contained in sections 107.101, 107.105, 107.107, 107.109, 107.111, 107.113, 107.117, 107.121, 107.123, Part 171, except section 171.1, Parts 172 through 199, including appendices, inclusive and Part 397.

5.6 On-Site Storage and Handling of Hydraulic Fracturing Additives

Prior to use, additives remain at the wellsite in the containers and on the trucks in which they are transported and delivered. Storage time is generally less than a week for economic and logistical reasons, materials are not delivered until fracturing operations are set to commence, and only the amount needed for scheduled continuous fracturing operations is delivered at any one time.

As detailed in Section 5.4.3, there are 12 classes of additives, based on their purpose or use; not all classes would be used at every well; and only one product in each class would typically be used per job. Therefore, although the chemical lists in Tables 5.5 and 5.6 reflect nearly 200 products, no more than 12 products and far fewer chemicals than listed would be present at one time at any given site.

When the hydraulic fracturing procedure commences, hoses are used to transfer liquid additives from storage containers to a truck-mounted blending unit. The flat-bed trucks that deliver liquid totes to the site may be equipped with their own pumping systems for transferring the liquid additive to the blending unit when fracturing operations are in progress. Flat-beds that do not have their own pumps rely on pumps attached to the blending unit. Additives delivered in tank trucks are pumped to the blending unit or the well directly from the tank truck. Dry additives are poured by hand into a feeder system on the blending unit. The blended fracturing solution is not stored, but is immediately mixed with proppant and pumped into the cased and cemented wellbore. This process is conducted and monitored by qualified personnel, and devices such as manual valves provide additional controls when liquids are transferred. Common observed practices during visits to drill sites in the northern tier of Pennsylvania included lined containments and protective barriers where chemicals were stored and blending took place.[37]

5.6.1 Summary of Additive Container Types

The most common containers are 220-gallon to 375-gallon high-density polyethylene (HDPE) totes, which are generally cube-shaped and encased in a metal cage. These totes have a bottom release port to transfer the chemicals, which is closed and capped during transport, and a top fill port with a screw-on cap and temporary lock mechanism. Photo 5.18 depicts a transport truck with totes.

[37] Alpha Environmental Consultants, Inc., 2009. *Technical Contributions to the Draft Supplemental Generic Environmental Impact Satement (dSGEIS) for the NYSDEC Oil, Gas and Solution Mining Regulatory Program.*

Photo 5.18 - Transport trucks with totes

To summarize, the storage containers at any given site during the short period of time between delivery and completion of continuous fracturing operations will consist of all or some of the following:

- Plastic totes encased in metal cages, ranging in volume from 220 gallons to 375 gallons, which are strapped on to flat bed trucks pursuant to USDOT and NYSDOT regulations
- Tank trucks (see Photo 5.19)
- Palletized 50-55 gallon bags, made of coated paper or plastic (40 bags per pallet, shrink-wrapped as a unit and then wrapped again in plastic)
- One-gallon jugs with perforated sealed twist lids stored in side boxes on the flat-bed
- Smaller double-bag systems stored in side boxes on the blending unit

5.6.2 *NYSDEC Programs for Bulk Storage*[38]

The Department regulates bulk storage of petroleum and hazardous chemicals under 6 NYCRR Parts 612-614 for Petroleum Bulk Storage (PBS) and Parts 595-597 for Chemical Bulk Storage (CBS). The PBS regulations do not apply to non-stationary tanks; however, all petroleum spills, leaks, and discharges must be reported to the Department (613.8).

Photo 5.19 - Transport trucks for water (above) and hydraulic fracturing acid (HCl) (below)

The CBS regulations that potentially may apply to fracturing fluids include non-stationary tanks, barrels, drums or other vessels that store 1000-Kg or greater for a period of 90 consecutive days. Liquid fracturing chemicals are stored in non-stationary containers but most likely will not be stored on-site for 90 consecutive days; therefore, those chemicals are exempt from Part 596,

[38] Alpha, 2009.

"Registration of Hazardous Substance Bulk Storage Tanks" unless the storage period criteria is exceeded. These liquids typically are trucked to the drill site in volumes required for consumptive use and only days before the fracturing process. Dry chemical additives, even if stored on site for 90 days, would be exempt from 6 NYCRR because the dry materials are stored in 55-lb bags secured on plastic-wrapped pallets.

The facility must maintain inventory records for all applicable non-stationary tanks including those that do not exceed the 90-day storage threshold. The CBS spill regulations and reporting requirements also apply regardless of the storage thresholds or exemptions. Any spill of a "reportable quantity" listed in Part 597.2(b), must be reported within 2 hours unless the spill is contained by secondary containment within 24 hours and the volume is completely recovered. Spills of any volume must be reported within two (2) hours if the release could cause a fire, explosion, contravention of air or water quality standards, illness, or injury. Forty-two of the chemicals listed in Table 5.6 are listed in Part 597.2(b).

5.7 Source Water for High-Volume Hydraulic Fracturing

As described below, it is estimated that 2.4 million to 7.8 million gallons of water may be used for a multi-stage hydraulic fracturing procedure in a 4,000-foot lateral wellbore. Operators may withdraw water from surface or ground water sources themselves or may purchase it from suppliers. The suppliers may be municipalities with excess capacity in their public supply systems, or industrial entities with wastewater effluent streams that meet usability criteria for hydraulic fracturing. Potential environmental impacts of water sourcing are discussed in Chapter 6, and mitigation measures including jurisdictional regulatory programs and potential alternate water sources are discussed in Chapter 7. Photos 5.20 a, b & c depict a water withdrawal facility along the Chemung River in the northern tier of Pennsylvania.

Factors affecting usability of a given source include:[39]

Availability – The "owner" of the source needs to be identified, contact made, and agreements negotiated.

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[39] URS Corporation, 2009. *A Survey of a Few Water Resources Issues Associated with Gas Production in the Marcellus Shale.* Water Consulting Services in Support of the Supplemental Generic Environmental Impact Statement for Natural Gas Production, NYSERDA Contract PO Number 10666.

Distance/route from the source to the point of use – The costs of trucking large quantities of water increases and water supply efficiency decreases when longer distances and travel times are involved. Also, the selected routes need to consider roadway wear, bridge weight limits, local zoning limits, impacts on residents, and related traffic concerns.

Available quantity – Use of fewer, larger water sources avoids the need to utilize multiple smaller sources.

Reliability – A source that is less prone to supply fluctuations or periods of unavailability would be more highly valued than an intermittent and less steady source.

Accessibility –Water from deep mines and saline aquifers may be more difficult to access than a surface water source unless adequate infrastructure is in place. Access to a municipal or industrial plant or reservoir may be inconvenient due to security or other concerns. Access to a stream may be difficult due to terrain, competing land uses, or other issues.

Quality of water – The fracturing fluid serves a very specific purpose at different stages of the fracturing process. The composition of the water could affect the efficacy of the additives and equipment used. The water may require pre-treatment or additional additives may be needed to overcome problematic characteristics.

Potential concerns with water quality include scaling from precipitation of barium sulfate and calcium sulfate; high concentrations of chlorides, which could increase the need for friction reducers; very high or low pH (e.g. water from mines); high concentrations of iron (water from quarries or mines) which could potentially plug fractures; microbes that can accelerate corrosion, scaling or other gas production; and high concentrations of sulfur (e.g. water from flu gas desulfurization impoundments), which could contaminate natural gas. In addition, water sources of variable quality could present difficulties.

Permittability – Applicable permits and approvals would need to be identified and assessed as to feasibility and schedule for obtaining approvals, conditions and limitations on approval that could impact the activity or require mitigation, and initial and ongoing fees and charges.

Preliminary discussions with regulating authorities would be prudent to identify fatal flaws or obstacles.

Disposal – Proper disposal of flowback from hydraulic fracturing will be necessary, or appropriate treatment for re-use provided. Utilizing an alternate source with sub-standard quality water could add to treatment and disposal costs.

Cost – Sources that have a higher associated cost to acquire, treat, transport, permit, access or dispose, typically will be less desirable.

5.7.1 Delivery of Source Water to the Well Pad

Water may be delivered by truck or pipeline directly from the source to the well pad, or may be delivered by trucks or pipeline from centralized water storage or staging facilities consisting of tanks or engineered impoundments. Photo 5.21 shows a fresh water pipeline in Bradford County, Pennsylvania, to move fresh water from an impoundment to a well pad.

At the well pad, water is typically stored in 500-barrel steel tanks.

Potential environmental impacts related to water transportation, including the number and duration of truck trips for moving both fluid and temporary storage tanks, are addressed in Chapter 6. Mitigation measures are described in Chapter 7.

5.7.2 Use of Centralized Impoundments for Fresh Water Storage

Operators have indicated that centralized water storage impoundments will likely be utilized as part of a water management plan. Such facilities would allow the operators to withdraw water from surface water bodies during periods of high flow and store the water for use in future hydraulic fracturing activities, thus avoiding or reducing the need to withdraw water during lower flow periods when the potential for negative impacts to aquatic environments and municipal drinking water suppliers is greater.

The proposed engineered impoundments would likely be constructed from compacted earth excavated from the impoundment site and then compressed to form embankments around the excavated area. Typically, such impoundments would then be lined to minimize the loss of water due to infiltration.

It is likely that an impoundment would service well pads within a radius of up to four miles, and that impoundment volume could be several million gallons with surface acreage of up to five acres. The siting and sizing of such impoundments would be affected by factors such as terrain, environmental conditions, natural barriers, and population density, as well as by the operators' lease positions. It is not anticipated that a single centralized impoundment would service wells from more than one well operator.

Photo 5.23 depicts a centralized freshwater impoundment and its construction.

5.7.2.1 Impoundment Regulation

Water stored within an impoundment represents potential energy which, if released, could cause personal injury, property damage and natural resource damage. In order for an impoundment to safely fulfill its intended function, the impoundment must be properly designed, constructed, operated and maintained.

As defined by Section 3 Title 5 of Article 15 of the Environmental Conservation Law (ECL), a dam is any artificial barrier, including any earthen barrier or other structure, together with its appurtenant works, which impounds or will impound waters. As such, any engineered impoundment designed to store water for use in hydraulic fracturing operations is considered to be a dam and is therefore subject to regulation in accordance with the ECL, NYSDEC's Dam Safety Regulations and the associated Protection of Waters permitting program.

Photos 5.20 a & b Fortuna SRBC-approved Chemung River water withdrawal facility, Towanda PA. Source:

Photo 5.20 c Fresh water supply pond. Black pipe in pond is a float to keep suction away from pond bottom liner. Ponds are completely enclosed by wire fence. Source: NYS DEC 2009.

Photo 5.21 Water pipeline from Fortuna central freshwater impoundments, Troy PA. Source: NYS DEC 2009.

Photo 5.23 Construction of freshwater impoundment in Upshur Co. WV. Source: Chesapeake Energy

Statutory Authority

Chapter 364, Laws of 1999 amended ECL Sections 15-0503, 15-0507 and 15-0511 to revise the applicability criteria for the dam permit requirement and provide the Department the authority to regulate dam operation and maintenance for safety purposes. Additionally the amendments established the dam owners' responsibility to operate and maintain dams in a safe condition.

Although the revised permit criteria, which are discussed below, became effective in 1999, implementing the regulation of dam operation and maintenance for all dams (regardless of the applicability of the permit requirement) necessitated the promulgation of regulations. As such, the Department issued proposed dam safety regulations in February 2008, followed by revised draft regulations in May 2009 and adopted the amended regulations in August 2009.These adopted regulations contain amendments to Part 673 and to portions of Parts 608 and 621 of Title 6 of the Official Compilation of Codes, Rules and Regulations of the State of New York.[40]

Permit Applicability

In accordance with ECL §15-0503 (1)(a), a Protection of Waters Permit is required for the construction, reconstruction, repair, breach or removal of an impoundment provided the impoundment has:

(1) a height equal to or greater than fifteen feet[41], or

(2) a maximum impoundment capacity equal to or greater than three million gallons[42].

If, however, either of the following exemption criteria apply, no permit is required:

(1) a height equal to or less than six feet regardless of the structure's impoundment capacity, or

(2) an impoundment capacity not exceeding one million gallons regardless of the structure's height

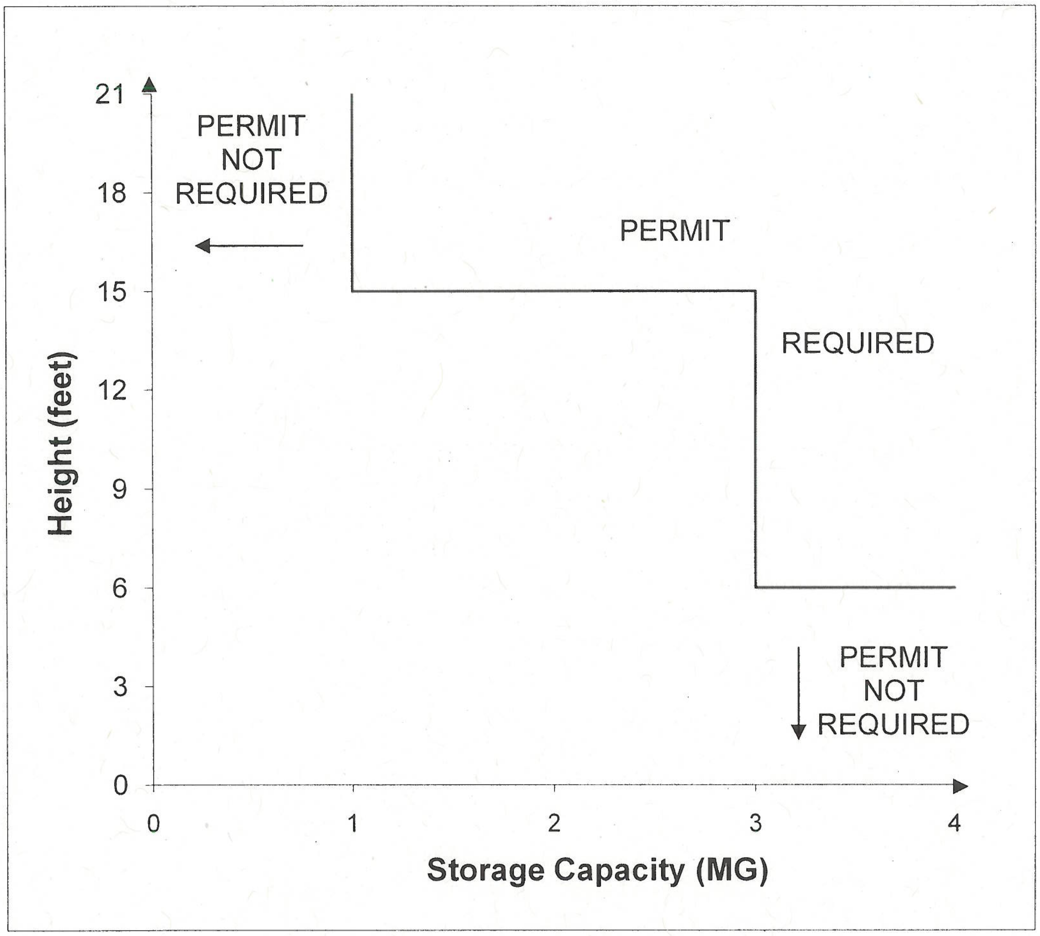
[40] NYSDEC Notice of Adoption of Amendments to Dam Safety Regulations

[41] Maximum height is measured as the height from the downstream [outside] toe of the dam at its lowest point to the highest point at the top of the dam.

[42] Maximum impounding capacity is measured as the volume of water impounded when the water level is at the top of the dam.

Figure 5.4 depicts the aforementioned permitting criteria and demonstrates that a permit is required for any impoundment whose height and storage capacity plot above or to the right of the solid line, while those impoundments whose height and storage capacity plot below or to the left of the solid line, do not require a permit.

Figure 5-4- Protection of Waters – Dam Safety Permitting Criteria



Protection of Waters - Dam Safety Permitting Process

If a proposed impoundment meets or exceeds the permitting thresholds discussed above, the well operator proposing use of the impoundment is required to apply for a Protection of Waters Permit though the Department's Division of Environmental Permits.

A pre-application conference is recommended and encouraged for permit applicants, especially those who are first-time applicants. Such a conference allows the applicant to explain the proposed project and to get preliminary answers to any questions concerning project plans, application procedures, standards for permit issuance and information on any other applicable permits pertaining to the proposed impoundment. It is also recommended that this conference occur early in the planning phase, prior to detailed design and engineering work, so that Department staff can review the proposal and comment on its conformance with permit issuance standards, which may help to avoid delays later in the process.

Application forms, along with detailed application instructions are available on the Department's website[43] and from the Regional Permit Administrator[44] for the county where the impoundment project is proposed. A complete application package[45] must include the following items:

- A completed Joint Application for Permit
- A completed Application Supplement D-1, which is specific to the construction, reconstruction or repair of a dam or other impoundment structure
- A location map showing the precise location of the project
- A plan of the proposed project
- Hydrological, hydraulic, and soils information, as required on the application form prescribed by the Department
- An Engineering Design Report sufficiently detailed for Department evaluation of the safety aspects of the proposed impoundment that shall include:
    - A narrative description of the proposed project;
    - The proposed Hazard Classification of the impoundment as a result of the proposed activities or project;
    - A hydrologic investigation of the watershed and an assessment of the hydraulic adequacy of the impoundment;

[43] Downloadable permit application forms are available at Hhttp://www.dec.ny.gov/permits/6338.htmlH.

[44] Contact information for the Department's Regional Permit Administrators is available on the Department's website at Hhttp://www.dec.ny.gov/about/558.htmlH.

[45] Further details regarding the permit application requirement are available on the instructions which accompany the Supplement D-1 application form which is available at Hhttp://www.dec.ny.gov/docs/permits_ej_operations_pdf/spplmntd1.pdfH.

- An evaluation of the foundation and surrounding conditions, and materials involved in the structure of the dam, in sufficient detail to accurately define the design of the dam and assess its safety, including its structural stability;

- Structural and hydraulic design studies, calculation and procedures, which shall, at a minimum, be consistent with generally accepted sound engineering practice in the field of dam design and safety; and

- A description of any proposed permanent instrument installations in the impoundment

- Construction plans and specifications that are sufficiently detailed for Department evaluation of the safety aspects of the dam

Additionally the following information may also be required as part of the permit application:

- Recent clear photographs of the project site mounted on a separate sheet labeled with the view shown and the date of the photographs.

- Information necessary to satisfy the requirements of the State Environmental Quality Review Act (SEQR), including: a completed Environmental Assessment Form (EAF) and, in certain cases, a Draft Environmental Impact Statement (DEIS)

- Information necessary to satisfy the requirements of the State Historic Preservation Act (SHPA) including a completed structural and archaeological assessment form and, in certain cases, an archaeological study as described by SHPA

- Written permission from the landowner for the filing of the project application and undertaking of the proposed activity.

- Other information which Department staff may determine is necessary to adequately review and evaluate the application.

In order to ensure that an impoundment is properly designed and constructed, the design, preparation of plans, estimates and specifications, and the supervision of the erection, reconstruction, or repair of an impoundment must be conducted by a licensed professional engineer. This individual should utilize the Department's technical guidance document "Guidelines for Design of Dams"[46], which conveys sound engineering practices and outlines

[46] "Guidelines for Design of Dams" is available on the Department's website at http://www.dec.ny.gov/docs/water_pdf/damguideli.pdf or upon request from the DEC Regional Permit Administrator.

hydrologic and other criteria that should be utilized in designing and constructing an engineered impoundment.

All application materials should be submitted to the appropriate Regional Permit Administrator for the county in which the project is proposed. Once the application is declared complete, the Department will review the applications, plans and other supporting information submitted and, in accordance with 6 NYCRR §608.7, may (1) grant the permit; (2) grant the permit with conditions as necessary to protect the health, safety, or welfare of the people of the state, and its natural resources; or (3) deny the permit.

The Department's review will determine whether the proposed impoundment is consistent with the standards contained within 6 NYCRR §608.8, considering such issues as:

(1) the environmental impacts of the proposal, including effects on aquatic, wetland and terrestrial habitats; unique and significant habitats; rare, threatened and endangered species habitats; water quality[47]; hydrology[48]; water course and waterbody integrity;

(2) the adequacy of design and construction techniques for the structure;

(3) operation and maintenance characteristics;

(4) the safe commercial and recreational use of water resources;

(5) the water dependent nature of a use;

(6) the safeguarding of life and property; and

(7) natural resource management objectives and values.

Additionally, the Department's review of the proposed impoundment will include the assignment of a Hazard Classification in accordance with 6 NYCRR§673.5. Hazard Classifications are assigned to dams and impoundments according to the potential impacts of a dam failure, the particular physical characteristics of the impoundment and its location, and may be irrespective of the size of the impoundment, as appropriate. The 4 potential Hazard Classifications, as defined by subdivision (b) of Section 673.5, are as follows:

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[47] Water Quality may include criteria such as temperature, dissolved oxygen, and suspended solids.

[48] Hydrology may include such criteria as water velocity, depth, discharge volume, and flooding potential

- Class “A” or “Low Hazard”: A failure is unlikely to result in damage to anything more than isolated or unoccupied buildings, undeveloped lands, minor roads such as town or country roads; is unlikely to result in the interruption of important utilities, including water supply, sewage treatment, fuel, power, cable or telephone infrastructure; and/or is otherwise unlikely to pose the threat of personal injury, substantial economic loss or substantial environmental damage.

- Class “B” or “Intermediate Hazard”: A failure may result in damage to isolate homes, main highways, and minor railroads; may result in the interruption of important utilities, including water supply, sewage treatment, fuel, power, cable or telephone infrastructure; and/or is otherwise likely to pose the threat of personal injury and/or substantial economic loss or substantial environmental damage. Loss of human life is not expected.

- Class “C” or “High Hazard”: A failure may result in widespread or serious damage to home(s); damage to main highways, industrial or commercial buildings, railroads, and/or important utilities, including water supply, sewage treatment, fuel, power, cable or telephone infrastructure; or substantial environmental damage; such that the loss of human life or widespread substantial economic loss is likely.

- Class “D” or “Negligible or No Hazard”: A dam or impoundment that has been breached or removed, or has failed or otherwise no longer materially impounds waters, or a dam that was planned but never constructed. Class “D” dams are considered to be defunct dams posing negligible or no hazard. The Department may retain pertinent records regarding such dams.

The basis for the issuance of a permit will be a determination that the proposal is in the public interest in that the proposal is reasonable and necessary, will not endanger the health, safety or welfare of the people of the State of New York, and will not cause unreasonable, uncontrolled or unnecessary damage to the natural resources of the state.

Timing of Permit Issuance

Application submission, time frames and processing procedures for the Protection of Waters Permit are all governed by the provisions of Article 70 of the ECL – the Uniform Procedures Act (UPA) – and its implementing regulations, 6 NYCRR § 621. In accordance with subdivision (a)(2)(iii) of Section 621 as recently amended, only repairs of existing dams inventoried by the Department are considered minor projects under the UPA and therefore the construction, reconstruction or removal of an impoundment is considered to be a major project and is thus subject to the associated UPA timeframes.

Failure to obtain the required permit before commencing work subjects the well operator and any contractors engaged in the work to DEC enforcement action which may include civil or criminal court action, fines, an order to remove structures or materials or perform other remedial action, or both a fine and an order.

Operation and Maintenance of Any Impoundment

The Department's document ""An Owners Guidance Manual for the Inspection and Maintenance of Dams in New York State" should be utilized by all impoundment owners, as it provides important, direct and indirect steps they can take to reduce the consequences of an impoundment failure.

The Dam Safety Regulations, as set forth in 6 NYCRR § 673 and amended August 2009, apply to any owner of any impoundment, regardless of whether the impoundment meets the permit applicability criteria previously discussed (unless otherwise specified). In accordance with the general provisions of Section 673.3, any owner of an impoundment must operate and maintain the impoundment and all appurtenant works in a safe condition. The owner of any impoundment found to be in violation of this requirement is subject to the provisions of ECL 15-0507 and 15-0511.

In order to ensure the safe operation and maintenance of an impoundment, a written Inspection and Maintenance Plan is required under 6 NYCRR §673.6 for any impoundment that (1) requires a Protection of Waters Permit due to its height and storage capacity as previously discussed, (2) has been assigned a Hazard Classification of Class "B" or "C", or (3) impounds waters which pose a threat of personal injury, substantial property damage or substantial natural resources damage in the event of a failure, as determined by the Department. Such a plan shall be retained by the impoundment owner and updated as necessary, must be made available to the Department upon request, and must include:

- detailed descriptions of all procedures governing: the operation, monitoring, and inspection of the dam, including those governing the reading of instruments and the recording of instrument readings; the maintenance of the dam; and the preparation and circulation of notifications of deficiencies and potential deficiencies;

- a schedule for monitoring, inspections, and maintenance; and

- any other elements as determined by the Department based on its consideration of public safety and the specific characteristics of the dam and its location

Additionally, the owner of any impoundment assigned a Hazard Classification of Class "B" or "C" must, in accordance with 6 NYCRRR §673, prepare an Emergency Action Plan and annual updates thereof , provide a signed Annual Certification to the Department's Dam Safety Section, conduct and report on Safety Inspections on a regular basis, and provide regular Engineering Assessments. Furthermore, all impoundment structures are subject to the Recordkeeping and Response to Request for Records provision of 6 NYCRR.

All impoundment structures, regardless of assigned Hazard Classification or permitting requirements, are subject to field inspections by the Department at its discretion and without prior notice. During such an inspection, the Department may document existing conditions through the use of photographs or videos without limitation. Based on the Field Inspection, the Department may create a Field Inspection Report and, if such a report is created for an impoundment with a Class "B" or "C" Hazard Classification, the Department will provide a copy of the report to the chief executive officer of the municipality or municipalities in which the impoundment is located.

To further ensure the safe operation and maintenance of all impoundments, 6 NYCRR §673.17 allows the Department to direct an impoundment owner to conduct studies, investigations and analyses necessary to evaluate the safety of the impoundment, or to remove, reconstruct or repair the impoundment within a reasonable time and in a manner specified by the Department.

5.8 Hydraulic Fracturing Design

Service companies design hydraulic fracturing procedures based on the rock properties of the prospective hydrocarbon reservoir. For any given area and formation, hydraulic fracturing design is an iterative process, i.e., it is continually improved and refined as development progresses and more data is collected. In a new area, it may begin with computer modeling to simulate various fracturing designs and their effect on the height, length and orientation of the induced fractures.[49] After the procedure is actually performed, the data gathered can be used to

[49] GWPC, 2009a. *Modern Shale Gas Development in the United States: A Primer*. p. 57.

optimize future treatments.[50] Data to define the extent and orientation of fracturing may be gathered during fracture treatments by use of microseismic fracture mapping, tilt measurements, tracers, or proppant tagging.[51,52] ICF International, under contract to NYSERDA to provide research assistance for this document, notes that fracture monitoring by these methods is not regularly used because of cost, but is commonly reserved for evaluating new techniques, determining the effectiveness of fracturing in newly developed areas, or calibrating hydraulic fracturing models.[53] Comparison of production pressure and flow-rate analysis to pre-fracture modeling is a more common method for evaluating the results of a hydraulic fracturing procedure.[54]

The objective in any hydraulic fracturing procedure is to limit fractures to the target formation. Excessive fracturing is undesirable from a cost standpoint because of the expense associated with unnecessary use of time and materials.[55] Economics would dictate limiting the use of water, additives and proppants, as well as the need for fluid storage and handling equipment, to what is needed to treat the target formation.[56] In addition, if adjacent rock formations contain water, then fracturing into them would bring water into the reservoir formation and the well. This could result in added costs to handle produced water, or could result in loss of economic hydrocarbon production from the well.[57]

5.8.1 Fracture Development

ICF reviewed how hydraulic fracturing is affected by the rock's natural compressive stresses.[58] The dimensions of a solid material are controlled by major, intermediate and minor principal stresses within the material. In rock layers in their natural setting, these stresses are vertical and

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[50] Ibid.

[51] Ibid.

[52] ICF, 2009., pp. 5-6.

[53] Ibid., p. 6.

[54] Ibid., pp. 6-8.

[55] GWPC, 2009a., p. 58.

[56] ICF International, 2009. *Technical Assistance for the Draft Supplemental Generic IES: Oil, Gas and Solution Mining Regulatory Program.* NYSERDA Agreement No. 9679., p. 14.

[57] GWPC, 2009a.. p. 58.

[58] ICF, 2009., pp. 14-15.

horizontal. Vertical stress increases with the thickness of overlying rock and exerts pressure on a rock formation to compress it vertically and expand it laterally. However, because rock layers are near infinite in horizontal extent relative to their thickness, lateral expansion is constrained by the pressure of the horizontally adjacent rock mass.[59]

Rock stresses may decrease over geologic time as a result of erosion acting to decrease vertical rock thickness. Horizontal stress decreases more slowly than vertical stress, so rock layers that are closer to the surface have a higher ratio of horizontal stress to vertical stress.[60]

Fractures form perpendicular to the direction of least stress. If the minor principal stress is horizontal, fractures will be vertical. The vertical fractures would then propagate horizontally in the direction of the major and intermediate principal stresses.[61]

ICF notes that the initial stress field created during deposition and uniform erosion may become more complex as a result of geologic processes such as non-uniform erosion, folding and uplift. These processes result in topographic features that create differential stresses, which tend to die out at depths approximating the scale of the topographic features.[62] ICF – citing PTTC, 2006 – concludes that: "In the Appalachian Basin, the stress state would be expected to lead to predominantly vertical fractures below about 2500 feet, with a tendency towards horizontal fractures at shallower depths."[63]

5.8.2 Methods for Limiting Fracture Growth

ICF reports that, despite ongoing laboratory and field experimentation, the mechanisms that limit vertical fracture growth are not completely understood.[64] Pre-treatment modeling, as discussed

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[59] Ibid.

[60] Ibid.

[61] Ibid.

[62] Ibid.

[63] Ibid.

[64] Ibid., p. 16

above, is one tool for designing fracture treatments based on projected fracture behavior. Other control techniques identified by ICF include:[65]

- Use of a friction reducer, which helps to limit fracture height by reducing pumping loss within fractures, thereby maintaining higher fluid pressure at the fracture tip;
- Measuring fracture growth in real time by microseismic analysis, allowing the fracturing process to be stopped upon achieving the desired fracturing extent; and
- Reducing the length of wellbore fractured in each stage of the procedure, thereby focusing the applied pressure and proppant placement, and allowing for modifications to the procedure in subsequent stages based on monitoring the results of each stage.

5.8.3 Hydraulic Fracturing Design – Summary

ICF provided the following summary of the current state of hydraulic fracturing design to contain induced fractures in the target formation:

> Hydraulic fracturing analysis, design, and field practices have advanced dramatically in the last quarter century. Materials and techniques are constantly evolving to increase the efficiency of the fracturing process and increase reservoir production. Analytical techniques to predict fracture development, although still imperfect, provide better estimates of the fracturing results. Perhaps most significantly, fracture monitoring techniques are now available that provide confirmation of the extent of fracturing, allowing refinement of the procedures for subsequent stimulation activities to confine the fractures to the desired production zone. [66]

Photo 5.23 shows personnel monitoring a hydraulic fracturing procedure.

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[65] Ibid., p.17

[66] Ibid., p. 19

Photo 5.23 Personnel monitoring a hydraulic fracturing procedure. Source: Fortuna Energy.

5.9 Hydraulic Fracturing Procedure

The fracturing procedure involves the controlled use of water and chemical additives, pumped under pressure into the cased and cemented wellbore. Composition, purpose, transportation, storage and handling of additives are addressed in previous sections of this document. Water and fluid management, including source, transportation, storage and disposition, are also discussed elsewhere in this document. Potential impacts, mitigation measures and the permit process are addressed in Chapters 6, 7 and 8. The discussion in this section describes only the specific physical procedure of high-volume hydraulic fracturing. Except where other references are specifically noted, operational details are derived from permit applications on file with the Department's Division of Mineral Resources and responses to the Department's information requests provided by several operators and service companies about their planned operations in New York.

Hydraulic fracturing occurs after the well is cased and cemented to protect fresh water zones and isolate the target hydrocarbon-bearing zone, and after the drilling rig and its associated equipment are removed. There will be at least two strings of cemented casing in the well during fracturing operations. The outer string (i.e., surface casing) extends below fresh ground water and would have been cemented to the surface before the well was drilled deeper. The inner string (i.e., production casing) typically extends from the ground surface to the toe of the horizontal well. Depending on the depth of the well and local geological conditions, there may be one or more intermediate casing strings between the surface and production strings. The inner production casing is the only casing string that will experience the high pressures associated with the fracturing treatment.[67] Anticipated Marcellus Shale fracturing pressures range from 5,000 pounds per square inch to 10,000 pounds per square inch, so production casing with a greater internal yield pressure than the anticipated fracturing pressure must be installed.

Before perforating the casing and pumping fracturing fluid into the well, the operator pumps fresh water or drilling mud to test the production casing. Test pumping is performed to at least the maximum anticipated treatment pressure, which is maintained for a period of time while the operator monitors pressure gauges. The purpose of this test is to verify, prior to pumping fracturing fluid, that the casing will successfully hold pressure and contain the treatment. Test pressure may exceed the maximum anticipated treatment pressure, but must remain below the casing's internal yield pressure.

The last step prior to fracturing is installation of a wellhead (referred to as a "frac tree") that is designed and pressure-rated specifically for the fracturing operation. Photo 5.24 depicts a frac tree that is pressure-rated for 10,000 pounds per square inch. Flowback equipment, including pipes, manifolds, a gas-water separator and tanks are connected to the frac tree and the system is pressure tested again.

[67] For more details on wellbore casing and cement: see Appendix 8 for current casing and cementing practices required for all wells in New York, Appendix 9 for additional permit conditions for wells drilled within the mapped areas of primary and principal aquifers, and Chapter 7 and Appendix 10 for proposed new permit conditions to address high-volume hydraulic fracturing.

Photo 5.24 - Three Fortuna Energy wells being prepared for hydraulic fracturing, with 10,000 psi well head and goat head attached to lines. Troy PA. Source: NYS DEC 2009

The hydraulic fracturing process itself is conducted in stages by successively isolating, perforating and fracturing portions of the horizontal wellbore starting with the far end, or toe. Reasons for conducting the operation in stages are to maintain sufficient pressure to fracture the entire length of the wellbore,[68] to achieve better control of fracture placement and to allow changes from stage to stage to accommodate varying geological conditions along the wellbore if necessary.[69] The length of wellbore treated in each stage will vary based on site-specific geology and the characteristics of the well itself, but may typically be 300 to 500 feet. In that case, the multi-stage fracturing operation for a 4,000 foot lateral would consist of eight to 13 fracturing stages. Each stage may require 300,000 to 600,000 gallons of water, so that the entire multi-stage fracturing operation for a single well would require 2.4 million to 7.8 million gallons

[68] GPWC, 2009a. *Modern Shale Gas Development in the United States: A Primer.*, p. 58

[69] Ibid.

of water.[70] More or less water may be used depending on local conditions, evolution in fracturing technology, or other factors which influence the operator's and service company's decisions.

The entire multi-stage fracturing operation for a single horizontal well typically takes two to five days, but may take longer for longer lateral wellbores, for many-stage jobs or if unexpected delays occur. Not all of this time is spent actually pumping fluid under pressure, as intervals are required between stages for preparing the hole and equipment for the next stage. Pumping rate may be as high as 1,260 to 3,000 gallons per minute.[71,72] At these rates, all the stages in the largest volume fracturing job described in the previous paragraph would require between approximately 40 and 100 hours of pumping.

The time spent pumping is the only time, except for when the well is shut-in, that wellbore pressure exceeds pressure in the surrounding rocks. Therefore, the hours spent pumping is the only time that fluid in fractures and in the rocks surrounding the fractures would move away from the wellbore instead of towards it. ICF International, under contract to NYSERDA, estimated the maximum rate of seepage in strata lying above the target Marcellus zone. Under most conditions evaluated by ICF, the seepage rate would be substantially less than 10 feet per day, or 5 inches per hour of pumping time. [73] More information about ICF's analysis is provided below in Section 5.11 and in Appendix 11.

Within each fracturing stage is a series of sub-stages, or steps.[74, 75] The first step is typically an acid treatment, which may also involve corrosion inhibitors and iron controls. Acid cleans the near-wellbore area accessed through the perforated casing and cement, while the other additives

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[70] Applications on file with the Department propose volumes on the lower end of this range. The higher end of the range is based on GWPC (2009a), pp. 58-59, where an example of a single-stage Marcellus frac treatment using 578,000 gallons of fluid is presented. Stage lengths used in the above calculation (300 – 500 feet) were provided by Fortuna Energy and Chesapeake Energy in presentations to Department staff during field tours of operations in the northern tier of Pennsylvania.

[71] ICF International, 2009, p. 3

[72] GPWC, 2009a. *Modern Shale Gas Development in the United States: A Primer.*, p. 59

[73] ICF International, 2009, pp. 27-28

[74] URS Corporation, 2009. *A Survey of a Few Water Resources Issues Associated With Gas Production in the Marcellus Shale.*, p. 2-12

[75] GWPC, 2009a. *Modern Shale Gas Development in the United States: A Primer,* pp. 58-60.

that may be used in this phase reduce rust formation and prevent precipitation of metal oxides that could plug the shale. The acid treatment is followed by the "slickwater pad," comprised primarily of water and a friction-reducing agent which helps optimize the pumping rate. Fractures form during this stage when the fluid pressure exceeds the minimum normal stress in the rock mass plus whatever minimal tensile stress exists.[76] The fractures are filled with fluid, and as the fracture width grows, more fluid must be pumped at the same or greater pressure to maintain and propagate the fractures.[77] As proppant is added, other additives such as a gelling agent and crosslinker may be used to increase viscosity and improve the fluid's capacity to carry proppant. Fine-grained proppant is added first, and carried deepest into the newly induced fractures, followed by coarser-grained proppant. Breakers may be used to reduce the fluid viscosity and help release the proppant into the fractures. Biocides may also be added to inhibit the growth of bacteria that could interfere with the process and produce hydrogen sulfide. Clay stabilizers may be used to prevent swelling and migration of formation clays. The final step is a freshwater flush to clean out the wellbore and equipment.

Photos 5.25 – 5.26 depict wellsites during hydraulic fracturing operations, labeled to identify the equipment that is present onsite.

[76] ICF, 2009. p. 16

[77] Ibid.


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Photo 5.25 (Above) Hydraulic Fracturing Operation

These photos show a hydraulic fracturing operation at a Fortuna Energy multi-well site in Troy PA. At the time the photos were taken, preparations for fracturing were underway but fracturing had not yet occurred for any of the wells.

Hydraulic Fracturing Operation Equipment

1. Well head and frac tree with 'Goat Head' (See Figure 5.x for more detail)
2. Flow line (for flowback & testing)
3. Sand separator for flowback
4. Flowback tanks
5. Line heaters
6. Flare stack
7. Pump trucks
8. Sand hogs
9. Sand trucks
10. Acid trucks
11. Frac additive trucks
12. Blender
13. Frac control and monitoring center
14. Fresh water impoundment
15. Fresh water supply pipeline
16. Extra tanks

Production equipment

17. Line heaters
18. Separator-meter skid
19. Production manifold

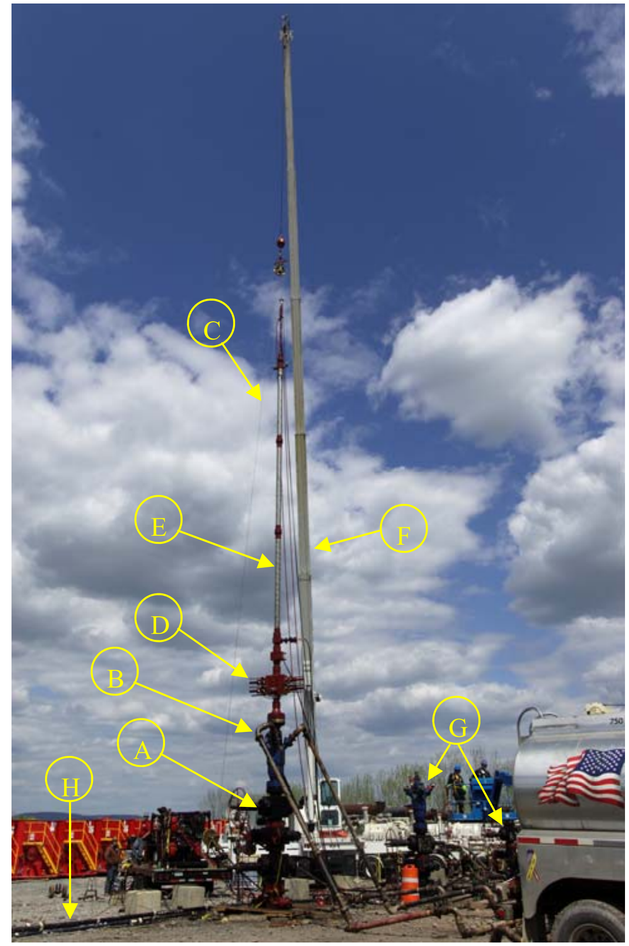

Photo 5.27 Wellhead and Frac Equipment
A. Well head and frac tree (valves)
B. Goat Head (for frac flow connections)
C. Wireline (used to convey equipment into wellbore)
D. Wireline Blow Out Preventer
E. Wireline lubricator
F. Crane to support wireline equipment
G. Additional wells
H. Flow line (for flowback & testing)

Photo 5.26 Fortuna multi-well pad after hydraulic fracturing of three wells and removal of most hydraulic fracturing equipment. Production equipment for wells on right side of photo. Source: Fortuna Energy, July, 2009.

5.10 Re-fracturing

Developers may decide to re-fracture a well to extend its economic life whenever the production rate declines significantly below past production rates or below the estimated reservoir potential.[78] According to ICF International, fractured Barnett shale wells generally would benefit from re-fracturing within five years of completion, but the time between fracture stimulations can be less than one year or greater than ten years.[79] However, Marcellus operators with whom the Department has discussed this question have stated their expectation that re-fracturing will be a rare event.

It is too early in the development of shale reservoirs in New York to predict the frequency with which re-fracturing of horizontal wells, using the slickwater method, may occur. ICF provided some general information on the topic of re-fracturing.

Wells may be re-fractured multiple times, may be fractured along sections of the wellbore that were not previously fractured, and may be subject to variations from the original fracturing technique.[80] The Department notes that while one stated reason to re-fracture may be to treat sections of the wellbore that were not previously fractured, this scenario does not seem applicable to Marcellus Shale development. Current practice in the Marcellus Shale in the northern tier of Pennsylvania is to treat the entire lateral wellbore, in stages, during the initial procedure.

Several other reasons may develop to repeat the fracturing procedure at a given well. Fracture conductivity may decline due to proppant embedment into the fracture walls, proppant crushing, closure of fractures under increased effective stress as the pore pressure declines, clogging from fines migration, and capillary entrapment of liquid at the fracture and formation boundary.[81] Re-fracturing can restore the original fracture height and length, and can often extend the fracture length beyond the original fracture dimensions.[82] Changes in formation stresses due to the

[78] ICF International, 2009, p. 18

[79] Ibid.

[80] Ibid., p. 17

[81] Ibid.

[82] Ibid.

reduction in pressure from production can sometimes cause new fractures to propagate at a different orientation than the original fractures, further extending the fracture zone. [83]

Factors that influence the decision to re-fracture include past well production rates, experience with other wells in the same formation, the costs of re-fracturing, and the current price for gas.[84] Factors in addition to the costs of re-fracturing and the market price for gas that determine cost-effectiveness include the characteristics of the geologic formation and the time value of money.[85]

Regardless of how often it occurs, if the high-volume hydraulic fracturing procedure is repeated it will entail the same type and duration of surface activity at the well pad as the initial procedure. The rate of subsurface fluid movement during pumping operations would be the same as discussed above. It is important to note, however, that between fracturing operations, while the well is producing, flow direction is towards the fracture zone and the wellbore. Therefore, total fluid movement away from the wellbore as a result of repeated fracture treatments would be less than the sum of the distance moved during each fracture treatment.

5.11 Fluid Return

After the hydraulic fracturing procedure is completed and pressure is released, the direction of fluid flow reverses. The well is "cleaned up" by allowing water and excess proppant to flow up through the wellbore to the surface. Both the process and the returned water are commonly referred to as “flowback.”

5.11.1 Flowback Water Recovery

Flowback water recoveries reported from horizontal Marcellus wells in the northern tier of Pennsylvania range between 9 and 35 percent of the fracturing fluid pumped. Flowback water volume, then, could be 216,000 gallons to 2.7 million gallons per well, based on Section 5.9’s pumped fluid estimate of 2.4 million to 7.8 million gallons. This volume is generally recovered within two to eight weeks, then the well’s water production rate sharply declines and levels off at a few barrels per day for the remainder of its producing life. URS Corporation, under contract to

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[83] Ibid., pp. 17-18

[84] Ibid., p. 18

[85] Ibid.

NYSERDA, reported that limited time-series data indicates that approximately 60 percent of the total flowback occurs in the first four days after fracturing.[86]

5.11.1.1 Subsurface Mobility of Fracturing Fluids

Reference is made in Section 5.9 to ICF International's calculations of the rate at which fracturing fluids could move away from the wellbore through fractures and the rock matrix during pumping operations. Appendix 11 provides ICF's full discussion of the principles governing potential fracture fluid flow. ICF's conclusion is that "hydraulic fracturing does not present a reasonably foreseeable risk of significant adverse environmental impacts to potential freshwater aquifers." [87] Specific conditions or analytical results supporting this conclusion include:

- The developable shale formations are vertically separated from potential freshwater aquifers by at least 1,000 feet of sandstones and shales of moderate to low permeability.
- The amount of time that fluids are pumped under pressure into the target formation is orders of magnitude less than the time that would be required for fluids to travel through 1,000 feet of low-permeability rock.
- The volume of fluid used to fracture a well could only fill a small percentage of the void space between the shale and the aquifer.
- Some of the chemicals in the additives used in hydraulic fracturing fluids would be adsorbed by and bound to the organic-rich shales.
- Diffusion of the chemicals throughout the pore volume between the shale and an aquifer would dilute the concentrations of the chemicals by several orders of magnitude.
- Any flow of fracturing fluid toward an aquifer through open fractures or an unplugged wellbore would be reversed during flowback, with any residual fluid further flushed by flow from the aquifer to the production zone as pressures decline in the reservoir during production.

5.11.2 Flowback Water Handling at the Wellsite

The GEIS describes (a) unchecked flow through a valve into a lined pit, (b) flow through a choke into the lined pit, and (c) flow to tanks. Operators have reported flowback rates of 60 – 130

[86] URS, p. 3-2

[87] ICF International, 2009., p. 34.

gallons per minute, without pumping, after high-volume hydraulic fracturing of the Marcellus in the northern tier of Pennsylvania.

An onsite lined reserve pit, if one is used, could be internally segmented to hold flowback water separately from drilling fluid and cuttings, or a separate pit could be constructed specifically for flowback water. In either case, existing regulations require fluid associated with each well to be removed within 45 days of the cessation of operations, unless the operator has submitted a plan to use the fluids in subsequent operations and the Department has inspected and approved the pit.[88] Operators have indicated plans to re-use as much flowback water as possible for future fracturing operations, diluting it with freshwater and applying other treatment methods if necessary to meet the usability characteristics described in Section 5.7. Operators could, therefore, propose to retain flowback water in an on-site lined pit longer for longer than 45 days, until the next well or well pad is ready for fracturing operations.

Dimensions of an on-site pit would vary based on topography and the configuration of the well pad. One operator reports a typical pit volume of 750,000 gallons. Pennsylvania limits wellsite impoundments to 250,000 gallons for a single or connected network of pits, and limits total volume of all well site pits on one tract or related tracts of land to 500,000 gallons.[89] The high rate and potentially high volume of flowback water generally requires additional temporary storage tanks to be staged onsite even if an onsite lined pit is used.

As discussed in Chapter 7, the Department proposes to require tanks for on-site (i.e., well pad) handling of flowback water unless additional compositional data is collected and provided on a site-specific basis to support an alternate proposal.

5.11.3 Flowback Water Characteristics

The following description of flowback water characteristics was provided by URS Corporation, under contract to NYSERDA. This discussion is based on a limited number of analyses from out-of-state operations, without corresponding complete compositional information on the fracturing additives that were used at the source wells. The Department did not direct or oversee

[88] 6 NYCRR 554.1(c)(3). For permitting and SEQRA purposes, well stimulation is part of the action of drilling the well.

[89] Alpha, 2009, p. 2-5.

sample collection or analysis efforts. Most fracturing fluid components are not included as analytes in standard chemical scans of flowback samples that were provided to DEC, so little information is available to document whether and at what concentrations most fracturing chemicals occur in flowback water.

The Department anticipates that, by the time the final SGEIS is published, additional data and analyses will be made public by the Marcellus Shale Committee and the Appalachian Shale Water Conservation and Management Committee. Because of the limited availability at this time of flowback water quality data, conservative and strict mitigation measures regarding flowback water handling are proposed in Chapter 7, and additional data will be required for alternative proposals.

Flowback fluids include the fracturing fluids pumped into the well, which consists of water and additives discussed in Section 5.4; any new compounds that may have formed due to reactions between additives; and substances mobilized from within the shale formation due to the fracturing operation. Some portion of the proppant may return to the surface with flowback, but operators strive to minimize proppant return: the ultimate goal of hydraulic fracturing is to convey and deposit the proppant within fractures in the shale to maximize gas flow.

Marcellus Shale is of marine origin and, therefore, contains high levels of salt. This is further evidenced by analytical results of flowback provided to NYSDEC by well operators and service companies from operations based in Pennsylvania. The results vary in level of detail. Some companies provided analytical results for one day for several wells, while other companies provided several analytical results for different days of the same well (i.e. time-series). Flowback parameters were organized by Chemicals Abstract Service (CAS) number, whenever available.

Typical classes of parameters present in flowback fluid are:

- Dissolved Solids (chlorides, sulfates, and calcium)
- Metals (calcium, magnesium, barium, strontium)
- Suspended solids
- Mineral scales (calcium carbonate and barium sulfate)

- Bacteria - acid producing bacteria and sulfate reducing bacteria
- Friction Reducers
- Iron solids (iron oxide and iron sulfide)
- Dispersed clay fines, colloids & silts
- Acid Gases (carbon dioxide, hydrogen sulfide)

A list of parameters detected in a limited set of analytical results is provided in Table 5.8. Typical concentrations of parameters other than radionuclides, based on limited data from PA and WV, are provided in Table 5.9. Radionuclides are separately discussed and tabulated in Section 5.11.3.3.

Table 5-8 - Parameters present in a limited set of flowback analytical results

CAS#	Parameters Detected in Flowback from PA and WV Operations
00056-57-5	4-Nitroquinoline-1 -oxide
00067-64-1	Acetone
07439-90-5	Aluminum
07440-36-0	Antimony
07664-41-7	Aqueous ammonia
07440-38-2	Arsenic
07440-39-3	Barium
00071-43-2	Benzene
00117-81-7	Bis(2-ethylhexyl)phthalate
07440-42-8	Boron
24959-67-9	Bromide
00075-25-2	Bromoform
07440-43-9	Cadmium
07440-70-2	Calcium
00124-48-1	Chlorodibromomethane
07440-47-3	Chromium
07440-48-4	Cobalt
07440-50-8	Copper
00057-12-5	Cyanide
00075-27-4	Dichlorobromomethane
00100-41-4	Ethyl Benzene
16984-48-8	Fluoride
07439-89-6	Iron
07439-92-1	Lead
07439-93-2	Lithium
07439-95-4	Magnesium
07439-96-5	Manganese

CAS#	Parameters Detected in Flowback from PA and WV Operations
00074-83-9	Methyl Bromide
00074-87-3	Methyl Chloride
07439-98-7	Molybdenum
00091-20-3	Naphthalene
07440-02-0	Nickel
00108-95-2	Phenol
57723-14-0	Phosphorus
07440-09-7	Potassium
07782-49-2	Selenium
07440-22-4	Silver
07440-23-5	Sodium
07440-24-6	Strontium
14808-79-8	Sulfate
14265-45-3	Sulfite
00127-18-4	Tetrachloroethylene
07440-28-0	Thallium
07440-32-6	Titanium
00108-88-3	Toluene
07440-66-6	Zinc

Parameters Detected in Flowback from PA and WV Operations (cont'd)
1,1,1-Trifluorotoluene
1,4-Dichlorobutane
2,4,6-Tribromophenol
2,5-Dibromotoluene
2-Fluorobiphenyl
2-Fluorophenol
4-Terphenyl-d14
Alkalinity
Alkalinity, Carbonate, as CaCO3
Alpha radiation
Aluminum, Dissolved
Barium Strontium P.S.
Barium, Dissolved
Beta radiation
Bicarbonates
Biochemical Oxygen Demand
Cadmium, Dissolved
Calcium, Dissolved
Chemical Oxygen Demand
Chloride
Chromium (VI)
Chromium (VI), dissolved
Chromium, (III)
Chromium, Dissolved
Cobalt, dissolved

Parameters Detected in Flowback from PA and WV Operations (cont'd)
Color
Conductivity
Hardness
Iron, Dissolved
Lithium, Dissolved
Magnesium, Dissolved
Manganese, Dissolved
Nickel, Dissolved
Nitrobenzene-d5
Nitrogen, Total as N
Oil and Grease
o-Terphenyl
Petroleum hydrocarbons
pH
Phenols
Potassium, Dissolved
Radium
Radium 226
Radium 228
Salt
Scale Inhibitor
Selenium, Dissolved
Silver, Dissolved
Sodium, Dissolved
Strontium, Dissolved
Sulfide
Surfactants
Total Alkalinity
Total Dissolved Solids
Total Kjeldahl Nitrogen
Total Organic Carbon
Total Suspended Solids
Xylenes
Zinc, Dissolved
Zirconium

Note that the parameters listed in Table 5.6 are based on the composition of additives used or proposed for use in New York. Parameters listed in Tables 5.8 and 5.9 are based on analytical results of flowback from operations in Pennsylvania or West Virginia. All information is for operations in the Marcellus shale.

Some parameters found in analytical results are due to additives used in fracturing, some are due to reactions between different additives, while others may have been mobilized from within the formation; still other parameters may have been contributed from more than one source. Further study would be required to identify the specific origin of each parameter.

Table 5-9 - Typical concentrations of flowback constituents based on limited samples from PA and WV, and regulated in NY[90]

CAS #	Parameter Name	Total Number of Samples	Number of Detects	Min	Median	Max	Units
	1,4-Dichlorobutane	1	1	198	198	198	%REC
	2,4,6-Tribromophenol[91]	1	1	101	101	101	%REC
	2-Fluorobiphenyl[92]	1	1	71	71	71	%REC
	2-Fluorophenol[93]	1	1	72.3	72.3	72.3	%REC
00056-57-5	4-Nitroquinoline-1 -oxide	24	24	1422	13908	48336	mg/L
	4-Terphenyl-d14 [94]	1	1	44.8	44.8	44.8	%REC
00067-64-1	Acetone	3	1	681	681	681	µg/L
	Alkalinity, Carbonate, as CaCO3	31	9	4.9	91	117	mg/L
07439-90-5	Aluminum	29	3	0.08	0.09	1.2	mg/L
07440-36-0	Antimony	29	1	0.26	0.26	0.26	mg/L
07664-41-7	Aqueous ammonia	28	25	12.4	58.1	382	mg/L
07440-38-2	Arsenic	29	2	0.09	0.1065	0.123	mg/L
07440-39-3	Barium	34	34	0.553	661.5	15700	mg/L
00071-43-2	Benzene	29	14	15.7	479.5	1950	µg/L
	Bicarbonates [95]	24	24	0	564.5	1708	mg/L
	Biochemical Oxygen Demand	29	28	3	274.5	4450	mg/L
00117-81-7	Bis(2-ethylhexyl)phthalate	23	2	10.3	15.9	21.5	µg/L
07440-42-8	Boron	26	9	0.539	2.06	26.8	mg/L
24959-67-9	Bromide	6	6	11.3	616	3070	mg/L

[90] Table 5.9 was provided by URS Corporation (based on data submitted to DEC) with the following note: Information presented is based on limited data from Pennsylvania and West Virginia. Characteristics of flowback from the Marcellus Shale in New York are expected to be similar to flowback from Pennsylvania and West Virginia, but not identical. In addition, the raw data for these tables came from several sources, with likely varying degrees of reliability. Also, the analytical methods used were not all the same for given parameters. Sometimes laboratories need to use different analytical methods depending on the consistency and quality of the sample; sometimes the laboratories are only required to provide a certain level of accuracy. Therefore, the method detection limits may be different. The quality and composition of flowback from a single well can also change within a few days soon after the well is fractured. This data does not control for any of these variables.

[91] Regulated under phenols.

[92] Regulated under phenols.

[93] Regulated under phenols.

[94] Regulated under phenols.

[95] Regulated under alkalinity.

CAS #	Parameter Name	Total Number of Samples	Number of Detects	Min	Median	Max	Units
00075-25-2	Bromoform	29	2	34.8	36.65	38.5	μg/L
07440-43-9	Cadmium	29	5	0.009	0.032	1.2	mg/L
07440-70-2	Calcium	55	52	29.9	5198	34000	mg/L
	Chemical Oxygen Demand	29	29	1480	5500	31900	mg/L
	Chloride	58	58	287	56900	228000	mg/L
00124-48-1	Chlorodibromomethane	29	2	3.28	3.67	4.06	μg/L
07440-47-3	Chromium	29	3	0.122	5	5.9	mg/L
07440-48-4	Cobalt	25	4	0.03	0.3975	0.58	mg/L
	Color	3	3	200	1000	1250	PCU
07440-50-8	Copper	29	4	0.01	0.035	0.157	mg/L
00057-12-5	Cyanide	7	2	0.006	0.0125	0.019	mg/L
00075-27-4	Dichlorobromomethane	29	1	2.24	2.24	2.24	μg/L
00100-41-4	Ethyl Benzene	29	14	3.3	53.6	164	μg/L
16984-48-8	Fluoride	4	2	5.23	392.615	780	mg/L
07439-89-6	Iron	58	34	0	47.9	810	mg/L
07439-92-1	Lead	29	2	0.02	0.24	0.46	mg/L
	Lithium	25	4	34.4	55.75	161	mg/L
07439-95-4	Magnesium	58	46	9	563	3190	mg/L
07439-96-5	Manganese	29	15	0.292	2.18	14.5	mg/L
00074-83-9	Methyl Bromide	29	1	2.04	2.04	2.04	μg/L
00074-87-3	Methyl Chloride	29	1	15.6	15.6	15.6	μg/L
07439-98-7	Molybdenum	25	3	0.16	0.72	1.08	mg/L
00091-20-3	Naphthalene	26	1	11.3	11.3	11.3	μg/L
07440-02-0	Nickel	29	6	0.01	0.0465	0.137	mg/L
	Nitrogen, Total as N	1	1	13.4	13.4	13.4	mg/L
	Oil and Grease	25	9	5	17	1470	mg/L
	o-Terphenyl [96]	1	1	91.9	91.9	91.9	%Rec
	pH	56	56	1	6.2	8	S.U.
00108-95-2	Phenol	23	1	459	459	459	μg/L
	Phenols	25	5	0.05	0.191	0.44	mg/L
57723-14-0	Phosphorus, as P	3	3	0.89	1.85	4.46	mg/L
07440-09-7	Potassium	31	13	59	206	7810	mg/L
07782-49-2	Selenium	29	1	0.058	0.058	0.058	mg/L
07440-22-4	Silver	29	3	0.129	0.204	6.3	mg/L
07440-23-5	Sodium	31	28	83.1	19650	96700	mg/L
07440-24-6	Strontium	30	27	0.501	821	5841	mg/L
14808-79-8	Sulfate (as SO4)	58	45	0	3	1270	mg/L
	Sulfide (as S)	3	1	29.5	29.5	29.5	mg/L
14265-45-3	Sulfite (as SO3)	3	3	2.56	64	64	mg/L
	Surfactants [97]	3	3	0.2	0.22	0.61	mg/L
00127-18-4	Tetrachloroethylene	29	1	5.01	5.01	5.01	μg/L
07440-28-0	Thallium	29	1	0.1	0.1	0.1	mg/L
07440-32-6	Titanium	25	1	0.06	0.06	0.06	mg/L
00108-88-3	Toluene	29	15	2.3	833	3190	μg/L
	Total Dissolved Solids	58	58	1530	93200	337000	mg/L
	Total Kjeldahl Nitrogen	25	25	37.5	122	585	mg/L
	Total Organic Carbon [98]	23	23	69.2	449	1080	mg/L

[96] Regulated under phenols.

[97] Regulated under foaming agents.

CAS #	Parameter Name	Total Number of Samples	Number of Detects	Min	Median	Max	Units
	Total Suspended Solids	29	29	30.6	146	1910	mg/L
	Xylenes	22	14	16	487	2670	µg/L
07440-66-6	Zinc	29	6	0.028	0.048	0.09	mg/L

5.11.3.1 Temporal Trends in Flowback Water Composition

The composition of flowback water changes with time, depending on a variety of factors. Limited time-series field data from Marcellus Shale flowback water taken at different times indicate that:

- The concentrations of total dissolved solids (TDS), chloride, and barium increase;
- The levels of radioactivity increase[99],
- Calcium and magnesium hardness increases;
- Iron concentrations increase, unless iron-controlling additives are used;
- Sulfate levels decrease;
- Alkalinity levels decrease, likely due to use of acid; and
- Concentrations of metals increase[100].

Available literature cited by URS corroborates the above summary regarding the changes in composition with time for TDS, chlorides, and barium. Fracturing fluids pumped into the well, and mobilization of materials within the shale may be contributing to the changes seen in hardness, sulfate, and metals. The specific changes would likely depend on the shale formation, fracturing fluids used and fracture operations control.

[98] Regulated via BOD, COD and the different classes/compounds of organic carbon.

[99] Limited data from vertical well operations in NY have reported the following ranges of radioactivity: alpha 22.41 – 18950 pCi/L; beta 9.68 – 7445 pCi/L; Radium^{226} 2.58 - 33 pCi/L.

[100] Metals such as aluminum, antimony, arsenic, barium, boron, cadmium, calcium, cobalt, copper, iron, lead, lithium, magnesium, manganese, molybdenum, nickel, potassium, radium, selenium, silver, sodium, strontium, thallium, titanium, and zinc have been reported in flowback analyses. It is important to note that each well did not report the presence of all these metals.

5.11.3.2 NYSDOH Chemical Categories

The GEIS identified high total dissolved solids (TDS), chlorides, surfactants, gelling agents and metals as the components of greatest concern in spent gel and foam fracturing fluids (i.e., flowback). Slickwater fracturing fluids proposed for Marcellus well stimulation may contain other additives such as corrosion inhibitors, friction reducers and microbiocides, in addition to the contaminants of concern identified in the GEIS. Most fracturing fluid additives used in a well can be expected in the flowback water, although some are expected to be consumed in the well (e.g., strong acids) or react during the fracturing process to form different products (e.g., polymer precursors).

At the DEC's request, NYSDOH provided the following additional discussion of flowback water relative to the chemical classes described in Section 5.4.3.1. DOH reviewed the same information that was discussed by URS, and noted the same data limitations.

Aromatic Hydrocarbons

Flowback analyses include some results for BTEX. In one set of the 16 flowback samples from wells in PA and NYS analyzed for these 4 compounds (including xylenes as total xylene), one sample contained benzene, toluene and xylene (total) ranging from 15 to 33 micrograms per liter (µg/L). In another set of 20 samples from wells in WV and PA, 13 had detectable amounts of benzene and 14 detectable amounts of other BTEX compounds. BTEX concentrations were higher in these samples compared to the first set (overall range of detected levels from 2.3 to 3190 µg/L). All of the higher BTEX concentrations came from wells in WV where a friction reducer product containing 10- 30% petroleum distillates was one of the highest volume fracturing additives.

Glycols

One flowback sample was analyzed for 5 different glycols. No glycols were detected in this sample, but the detection limits were relatively high (20,000 µg/L).

Glycol Ethers

Flowback samples were not analyzed for glycol ethers.

Alcohols

Flowback samples were not analyzed for alcohols.

Amides

One flowback sample included analysis for acrylamide, which was not detected (< 1.5 μg/L). Sixteen flowback samples were analyzed for sodium polyacrylate as an indicator of a scale inhibitor that included a polymer composed of both acrylic acid and acrylamide. All samples contained sodium polyacrylate at levels ranging from 450 to 1350 mg/L (1 mg/L = 1000 μg/L). Since this analysis targeted a polymerized reaction product and not the individual monomers, it is unclear from these data how much of the monomers, if any, occurred in the flowback.

Amines

Flowback samples were not analyzed for amines.

Nineteen flowback samples from wells in PA and WV were analyzed for 3 nitrosamines, and none were detected in any samples (most detection limits were < 10 μg/L; one set was < 96.2 μg/L and one set was < 1020 μg/L).

Trihalomethanes

Bromoform, chloroform, bromodichloromethane and chlorodibromomethane are collectively referred to as trihalomethanes (THMs). These are not listed as components of any hydraulic fracturing products reviewed by DOH. However, THMs were reported in flowback fluid samples from Marcellus wells in West Virginia. THMs commonly occur as byproducts of drinking water disinfection when disinfectants react with naturally occurring organic matter and salts in the water. Chloroform, bromodichloromethane and dibromochloromethane cause cancer in laboratory animals exposed to high levels over their lifetimes. Chloroform, bromodichloromethane and dibromochloromethane are also known to cause non-cancer effects in laboratory animals after high levels of exposure, primarily on the liver, kidney, nervous system and on their ability to bear healthy offspring.

THMs were only detected in flowback samples collected immediately following fracturing from two sets of WV flowback data. THMs could have been present in the source water used for fracturing these wells or could have been produced during fracturing if chlorine- or brominecontaining fracturing additives were used. Detected levels were 2.24 μg/L in one sample for bromodichloromethane, 3.67 μg/L in one sample for chlorodibromomethane and 34.8 to 38.5 μg/L in two samples for bromoform. Chloroform was not detected in these samples (all either <1 or <10 μg/L).

Organic Acids, Salts and Related Chemicals

Flowback samples were not analyzed for organic acids or related chemicals.

Minerals, Metals, Other Characteristics (e.g., TDS)

Inorganic chemicals are constituents of fracturing fluid products and also occur in flowback water and production brines when they are dissolved from rock formations during well development and production. Based on Marcellus flowback samples (primarily from wells in WV and PA), minerals and metals likely to be present in flowback fluid are similar to those found in production water from many NYS geological formations (e.g., GEIS, Table 15.4). The main constituents of concern are the same as those discussed in Chapter 9, Section H of the GEIS: chlorides, heavy metals and high total dissolved solids (TDS).

The discussion in the 1992 GEIS regarding these constituents of concern appears to be applicable to flowback water from hydraulically fractured Marcellus wells. Limited flowback sampling suggests mineral and metal content increases in samples collected later in the flowback process. Chloride and TDS levels in Marcellus late flowback samples are similar to levels from other formations discussed in the GEIS.

Microbiocides

Flowback samples were not analyzed for microbiocide chemicals.

Other Constituents

Formaldehyde was not detected (<1000 μg/L) in chemical analysis of three flowback samples from PA wells. Flowback samples were not analyzed for 1,4-Dioxane.

5.11.3.3 Naturally Occurring Radioactive Materials in Flowback Water

Several radiological parameters were detected in flowback samples, as shown in the following tabulations.

Table 5-10- Concentrations of NORM constituents based on limited samples from PA and WV.

CAS #	Parameter Name	Total Number of Samples	Number of Detects	Min	Median	Max	Units
--	Gross Alpha	8	8	22.41	--	18,950	pCi/L
--	Gross Beta	8	8	62	--	7,445	pCi/L
7440-14-4	Total Alpha Radium	6	6	3.8	--	1,810	pCi/L
7440-14-4	Radium-226	3	3	2.58	--	33	pCi/L
7440-14-4	Radium-228	3	3	1.15	--	18.41	pCi/L

5.12 Flowback Water Treatment, Recycling and Reuse

Operators have expressed the objective of maximizing their reuse of flowback water for subsequent fracturing operations at the same well pad or other well pads. This involves dilution of the flowback water with fresh water or more sophisticated treatment options. Regardless of the treatment objective, whether for reuse or direct discharge, the three basic issues that need consideration when developing water treatment technologies are:[101]

1. Influent (i.e., flowback water) parameters and their concentrations
2. Parameters and their concentrations allowable in the effluent (i.e., in the reuse water)
3. Disposal of residuals

Untreated flowback water composition is discussed in Section 5.11.3. Table 5.10 summarizes allowable concentrations after treatment (and prior to potential additional dilution with fresh water).[102]

Table 5-11 - Maximum allowable water quality requirements for fracturing fluids, based on input from one expert panel on Barnett Shale

Constituent	Concentration
Chlorides	3,000 - 90,000 mg/l
Calcium	350 - 1,000 mg/l

[101] URS Corporation, 1990. p. 5-2

[102] URS Corporation, 1990, p. 5-3

Constituent	Concentration
Suspended Solids	< 50 mg/l
Entrained oil and soluble organics	< 25 mg/l
Bacteria	cells/100 ml < 100
Barium	Low levels

The following factors influence the decision to utilize on-site treatment and the selection of specific treatment options:[103]

Operational

- Flowback fluid characteristics, including scaling and fouling tendencies
- On-site space availability
- Processing capacity needed
- Solids concentration in flowback fluid, and solids reduction required
- Concentrations of hydrocarbons in flowback fluid, and targeted reduction in hydrocarbon[104]
- Species and levels of radioactivity in flowback
- Access to freshwater sources
- Targeted recovery rate
- Impact of treated water on efficacy of additives
- Availability of residuals disposal options

Cost

- Capital costs associated with treatment system

[103] Ibid.

[104] Liquid hydrocarbons have not been detected in all Marcellus Shale gas analyses.

- Transportation costs associated with freshwater
- Increase or decrease in fluid additives from using treated flowback fluid

Environmental

- On-site topography
- Density of neighboring population
- Proximity to freshwater sources
- Other demands on freshwater in the vicinity
- Regulatory environment

5.12.1 Physical and Chemical Separation[105]

Some form of physical and/or chemical separation will be required as a part of on-site treatment. Physical and chemical separation technologies typically focus on the removal of oil and grease[106] and suspended matter from flowback.

The physical separation technologies include hydrocyclones, filters, and centrifuges; the size of constituents in flowback fluid drives separation efficiency. Chemical separation utilizes coagulants and flocculants to break emulsions (dissolved oil) and to remove suspended particles.

Modular physical and chemical separation units have been used in the Barnett Shale and Powder River Basin.

5.12.2 Dilution

The dilution option involves blending minimally treated flowback with freshwater to make it usable for future fracturing operations. However, this methodology may be limited by the extent to which high concentrations of different parameters in flowback adversely affect the desired

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[105] URS Corporation, 2009, p. 5-6.

[106] Oil and grease are not expected in the Marcellus.

fracturing fluid properties.[107] Concentrations of chlorides, calcium, magnesium, barium, carbonates, sulfates, solids and microbes in flowback water may be too high to use as-is. The demand for friction reducers increases when the chloride concentration increases; the demand for scale inhibitors increases when concentrations of calcium, magnesium, barium, carbonates, or sulfates increase; biocide requirements increase when the concentration of microbes increases. The current recycling practice of blending flowback with freshwater involves balancing the additional freshwater water needs with the additional additive needs. [108] As stated above, some form of physical and/or chemical separation is typically needed prior to recycling flowback.[109] Service companies and chemical suppliers may develop additive products that are more compatible with the aforementioned flowback water parameters.

URS suggests that compatibility mixing studies be performed prior to the actual blending of flowback water and freshwater in the field.[110] URS further reported that experts in the field suggest that flowback water and freshwater be evaluated multiple times during the year to assess potential seasonal variations and their impact on bacterial activity and water quality. Use of friction reducers, scale inhibitors, biocides, etc. would need to be modulated based on the composition and characteristics of the blend.[111]

5.12.2.1 Centralized Storage of Flowback Water for Dilution and Reuse

Operators may propose to store flowback water prior to or after dilution in the onsite lined pits or tanks discussed in Section 5.11.2, or in centralized facilities consisting of tanks or one or more engineered impoundments. Water would be moved to and from the centralized facilities by truck or pipeline. Operators have informed the Department that centralized impoundments constructed for this purpose would range in surface area from less than one acre to five acres, and would range in capacity from one to 16 million gallons. Depending on topography, such impoundments would serve well pads within up to a four-mile radius. Storage impoundments would be fenced, with locked gates, to restrict access of non-company personnel and wildlife. Cover systems may

[107] URS Corporation, 2009. p. 5-1

[108] URS Corporation, 2009. p. 5-2.

[109] Ibid.

[110] URS, p. 5-2

[111] URS, p. 5-2

be employed to further restrict access by birds and other wildlife. Operators describe plans to use dual liner systems with leak detection, along with piezometer wells on the perimeter of the impoundment. One operator who has used centralized flowback impoundments in another state reports the following typical design characteristics:

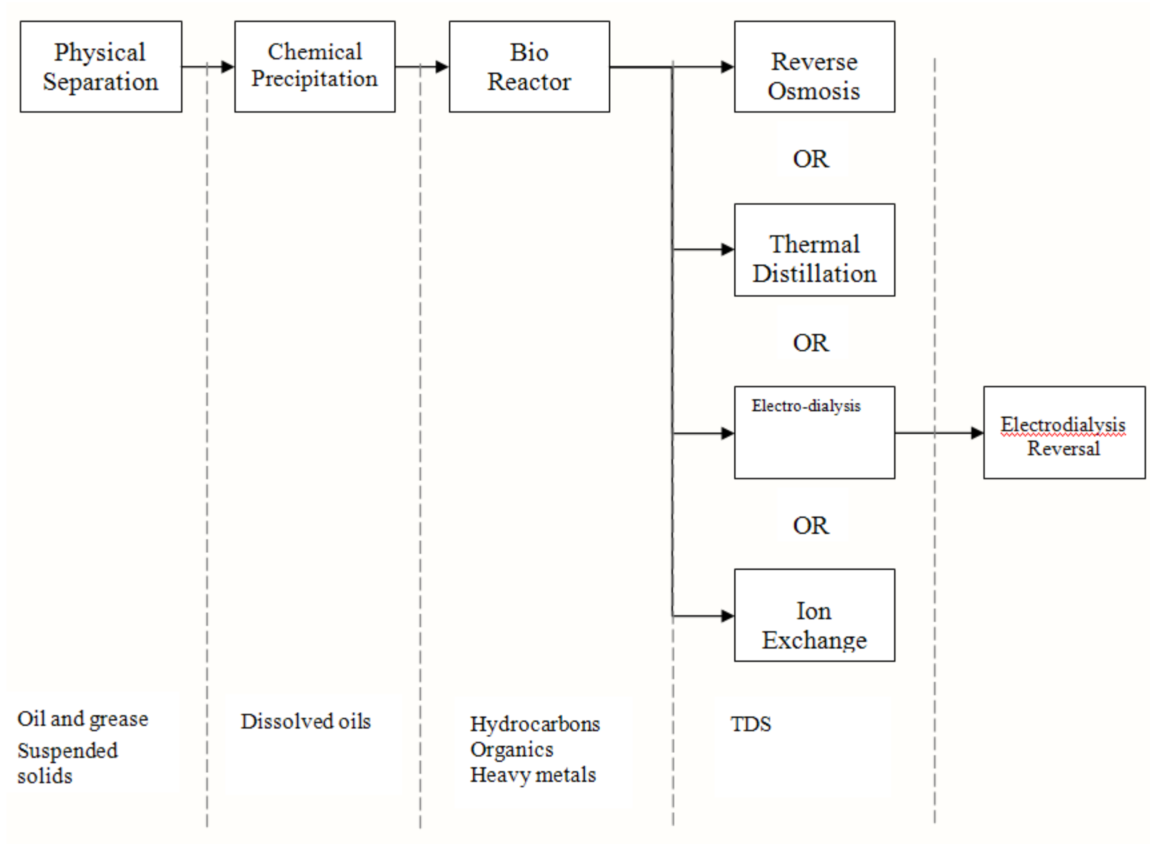
- A liner system with an upper (primary) 60-mil liner of high density polyethylene (HDPE) geomembrane and a lower (secondary) 40-mil liner of HDPE geomembrane with a geocomposite layer underneath.
- A geocomposite layer between the two geomembrane liners.
- A leak detection system installed in the interstitial space between the two liners within a trench placed below the impoundment at its lowest point of elevation.

5.12.2 Other On-Site Treatment Technologies[112]

One of the several on-site treatment technology configurations is illustrated in Figure 5.5.

[112] URS Corporation, 2009.

Figure 5-5 - One configuration of potential on-site treatment technologies.



5.12.2.1 Membranes / Reverse Osmosis

Membranes are an advanced form of filtration, and may be used to treat TDS in flowback. The technology allows water to pass through the membrane - the permeate - but the membrane blocks passage of suspended or dissolved particles larger than the membrane pore size. This method may be able to treat TDS concentrations up to approximately 30,000 mg/L, and produce water with TDS concentrations between 200 and 500 mg/L. This technology generates a residual - the concentrate - that would need proper disposal. The flowback water recovery rate for most membrane technologies is typically between 50-75 percent. Membrane performance may be impacted by scaling and/or microbiological fouling. Flowback water would likely require extensive pretreatment before it is sent through a membrane.

Reverse osmosis (RO) is a membrane technology that uses osmotic pressure on the membrane to provide passage of high-quality water.

Modular membrane technology units have been used in the Barnett Shale.

5.12.2.2 Thermal Distillation

Thermal distillation utilizes evaporation and crystallization techniques that integrate a multi-effect distillation column, and this technology may be used to treat flowback water with a large range of parameter concentrations. For example, thermal distillation may be able to treat TDS concentrations from 5,000 to over 150,000 mg/L, and produce water with TDS concentrations between 50 and 150 mg/L. The resulting residual salt would need appropriate disposal. This technology is resilient to fouling and scaling, but is energy intensive and has a large footprint.

Modular thermal distillation units have been used in the Barnett Shale.

5.12.2.3 Ion Exchange

Ion exchange units utilize different resins to preferentially remove certain ions. When treating flowback, the resin would be selected to preferentially remove sodium ions. The required resin volume and size of the ion exchange vessel would depend on the salt concentration and flowback volume treated.

The Higgins Loop is one version of ion exchange that has been successfully used in Midwest coal bed methane applications. The Higgins Loop uses a continuous countercurrent flow of flowback fluid and ion exchange resin. High sodium flowback fluid can be fed into the absorption chamber to exchange for hydrogen ions. The strong acid cation resin is advanced to the absorption chamber through a unique resin pulsing system.

Modular ion exchange units have been used in the Barnett Shale.

5.12.2.4 Electrodialysis

These treatment units are configured with alternating stacks of cation and anion membranes that allow passage of flowback fluid. The electric current applied to the stacks forces anions and cations to migrate in different directions.

Electrodialysis Reversal (EDR) is similar to electrodialysis, but its electric current polarity may be reversed as needed. This current reversal acts as a backwash cycle for the stacks which reduces scaling on membranes. EDR offers lower electricity usage than standard reverse osmosis systems and can potentially reduce salt concentrations in the treated water to less than 200 mg/L.

Table 5.12 compares EDR and RO by outlining key characteristics of both technologies.

Table 5-12 - Treatment capabilities of EDR and RO Systems

Criteria	EDR	RO
Acceptable influent TDS (mg/L)	400-3,000	100-15,000
Salt removal capacity	50-95%	90-99%
Water recovery rate	85-94%	50-75%
Allowable Influent Turbidity	Silt Density Index (SDI) < 12	SDI < 5
Operating Pressure	<50 psi	> 100 psi
Power Consumption	Lower for <2,500 mg/L TDS	Lower for >2,500 mg/L TDS
Typical Membrane Life	7-10 years	3-5 years

Modular electrodialysis units have been used in the Barnett Shale and Powder River Basin.

5.12.2.5 Ozone/Ultrasonic/Ultraviolet

These technologies are expected to oxidize and separate hydrocarbons, heavy metals, biological films and bacteria from flowback fluid. The microscopic air bubbles in supersaturated ozonated water and/or ultrasonic transducers cause oils and suspended solids to float.

5.12.3 Comparison of Potential On-Site Treatment Technologies

A comparison of performance characteristics associated with on-site treatment technologies is provided in Table 5.13.[113]

[113] URS Corporation, 2009, p. 5-8.

Table 5-13 - Summary of Characteristics of On-Site Flowback Water Treatment Technologies

Characteristics	Filtration	Ion Exchange	Reverse Osmosis	EDR	Thermal Distillation
Energy Cost	Low	Low	Moderate	High	High
Energy Usage vs. TDS	N/A	Low	Increase	High Increase	Independent
Applicable to	All Water types	All Water types	Moderate TDS	High TDS	High TDS
Plant / Unit size	Small / Modular	Small / Modular	Modular	Modular	Large
Microbiological Fouling	Possible	Possible	Possible	Low	N/A
Complexity of Technology	Easy	Easy	Moderate / High Maintenance	Regular Maintenance	Complex
Scaling Potential	Low	Low	High	Low	Low
Theoretical TDS Feed Limit (mg/L)	N/A	N/A	32,000	40,000	100,000+
Pretreatment Requirement	N/A	Filtration	Extensive	Filtration	Minimal
Final Water TDS	No impact	200-500 ppm	200-500 ppm	200-1000 ppm	< 10 mg/L
Recovery Rate (Feed TDS >20,000 mg/L)	N/A	N/A	30-50%	60-80%	75-85%

5.13 Waste Disposal

5.13.1 Cuttings from Mud Drilling

The GEIS discusses on-site burial of cuttings generated during air drilling. This option is also viable for cuttings generated during drilling with fresh water as the drilling fluid. However, cuttings that are generated during drilling with polymer- or oil-based muds must be removed from the site by a permitted Part 364 Waste Transporter and properly disposed in a solid waste landfill. Operators should consult with the landfill operator and with the Division of Solid and Hazardous Materials on a site-specific basis regarding landfill options relative to measured NORM levels in the cuttings.

5.13.2 Reserve Pit Liner from Mud Drilling

The GEIS discusses on-site burial, with the landowner's permission, of the plastic liner used for the reserve pit for air-drilled wells. This option is also viable for wells where fresh-water is the drilling fluid. However, pit liners for reserve pits where polymer- or oil-based drilling muds are used must be removed from the site by a permitted Part 364 Waste Transporter and properly disposed in a solid waste landfill.

5.13.3 Flowback Water

As discussed in Section 5.12, options exist or are being developed for treatment, recycling and reuse of flowback water. Nevertheless, proper disposal is required for flowback water that is not reused. Factors which could result in a need for disposal instead of reuse include lack of reuse opportunity (i.e., no other wells being fractured within reasonable time frames or a reasonable distance), prohibitively high contaminant concentrations which render the water untreatable to usable quality, or unavailability or infeasibility of treatment options for other reasons.

Flowback water requiring disposal is considered industrial wastewater, like many other water use byproducts. The Department has an EPA-approved program for the control of wastewater discharges. Under New York State law, the program is called the State Pollutant Discharge Elimination System and is commonly referred to as SPDES. The program controls point source discharges to ground waters and surface waters. SPDES permits are issued to wastewater dischargers, including POTW's, and include specific discharge limitations and monitoring requirements. The effluent limitations are the maximum allowable concentrations or ranges for various physical, chemical, and/or biological parameters to ensure that there are no impacts to the receiving water body.

Potential flowback water disposal options discussed in the GEIS include:

- injection wells, which are regulated under both the Department's SPDES program and the federal Underground Injection Control ("UIC") program,
- municipal sewage treatment facilities, and
- out-of-state industrial treatment plants.

Road spreading for dust control and deicing (by a Part 364 Transporter with local government approval) is also discussed in the GEIS as a general disposition method used in New York for well-related fluids (not an option for flowback water). Use of existing or new private in-state waste water treatment plants, and injection for enhanced resource recovery in oil fields have also been suggested. More information about each of these options is presented below.

5.13.3.1 Injection Wells

Discussed in Chapter 15 of the GEIS, injection wells for disposal of brine associated with oil and gas operations are classified as Class IID in EPA's UIC program and require federal permits. Under the Department's SPDES program, these wells have been categorized and regulated as industrial discharges. The primary objective of both programs is protection of underground sources of drinking water, and neither the EPA nor the DEC issues a permit without a demonstration that injected fluids will remain confined in the disposal zone and isolated from fresh water aquifers. As noted in the 1992 Findings Statement, the permitting process for brine disposal wells "require[s] an extensive surface and subsurface evaluation which is in effect a supplemental EIS addressing technical issues. An additional site-specific environmental assessment and SEQR determination are required."

UIC permit requirements will be included by reference in the SPDES permit, and the Department may propose additional monitoring requirements and/or discharge limits for inclusion in the SPDES permit. A well permit issued by the Division of Mineral Resources is also required to drill or convert a well deeper than 500 feet for brine disposal. This permit is not issued until the required UIC and SPDES permits have been approved. More information about the required analysis and mitigation measures considered during this review is provided in Chapter 7. Because of the 1992 Finding that brine disposal wells require site-specific SEQRA review, mitigation measures are discussed in Chapter 7 for informational purposes only and are not being proposed on a generic basis.

5.13.3.3 Municipal Sewage Treatment Facilities

Municipal sewage treatment facilities, known as Publicly Owned Treatment Works ("POTWs") are regulated by the Department's Division of Water ("DOW"). POTWs typically discharge treated wastewater to surface water bodies, and operate under SPDES permits which include specific discharge limitations and monitoring requirements. The effluent limitations are the maximum allowable concentrations or ranges for various physical, chemical, and/or biological parameters to ensure that there are no impacts to the receiving water body.

In general, POTWs must have a DEC-approved pretreatment program for accepting any industrial waste. POTWs must also notify DEC of any new industrial waste they plan to receive at their facility. POTWs are required to perform certain analyses to ensure they can handle the waste without upsetting their system or causing a problem in the receiving water. Ultimately, DEC needs to approve such analysis and modify SPDES permits as needed to insure water quality standards in receiving waters are maintained at all times. More detailed discussion of the potential environmental impacts and how they are mitigated is presented in Chapters 6 and 7.

5.13.3.4 Out-of-State Treatment Plants

The only regulatory role DEC has over disposal of flowback water at out-of-state municipal or industrial treatment plants is that transport of these fluids, which are considered industrial waste, must be by a licensed Part 364 Transporter.

For informational purposes, Table 5.14 lists out-of-state plants that have been proposed for disposition of flowback water recovered in New York.

Table 5-14 - Out-of-state treatment plants proposed for disposition of NY flowback water

Treatment Facility	**Location**	**County**
Advanced Waste Services	New Castle, PA	Lawrence
Eureka Resources	Williamsport, PA	Lycoming
Lehigh County Authority Pretreatment Plant	Fogelsville, PA	Lehigh
Liquid Assets Disposal	Wheeling, WV	Ohio
Municipal Authority of the City of McKeesport	McKeesport, PA	Allegheny
PA Brine Treatment, Inc.	Franklin, PA	Venango
Sunbury Generation	Shamokin Dam, PA	Snyder
Tri-County Waste Water Management	Waynesburg, PA	Greene
Tunnelton Liquids Co.	Saltsburg, PA	Indiana
Valley Joint Sewer Authority	Athens, PA	Bradford
Waste Treatment Corporation	Washington, PA	Washington

5.13.3.5 Road Spreading

Consistent with past practice regarding flowback water disposal, in January 2009, the DEC's Division of Solid and Hazardous Materials ("DSHM"), which is responsible for oversight of the Part 364 program, released a notification to haulers applying for, modifying, or renewing their Part 364 permit that flowback water may not be spread on roads and must be disposed of at facilities authorized by the Department or transported for use or re-use at other gas or oil wells where acceptable to the Division of Mineral Resources. This notification is included as Appendix 12.

5.13.3.6 Private In-State Industrial Treatment Plants

Industrial facilities could be constructed or converted in New York to treat flowback water. Such facilities would require a SPDES permit for any discharge. Again, the SPDES permit for a dedicated treatment facility would include specific discharge limitations and monitoring requirements. The effluent limitations are the maximum allowable concentrations or ranges for various physical, chemical, and/or biological parameters to ensure that there are no impacts to the receiving water body.

5.13.3.7 Enhanced Oil Recovery

Waterflooding is an enhanced oil recovery technique whereby water is injected into partially depleted oil reservoirs to displace additional oil and increase recovery. Waterflood operations in New York are regulated under Part 557 of the Department's regulations and under the EPA's Underground Injection Control Program.

EPA reviews proposed waterflood injectate to determine the threat of endangerment to underground sources of drinking water. Operations that are authorized by rule are required to submit an analysis of the injectate anytime it changes, and operations under permit are required to modify their permits to inject water from a new source. At this time, no waterflood operations in New York have EPA approval to inject flowback water.

5.13.4 Solid Residuals from Flowback Water Treatment

URS Corporation reports that residuals disposal from the limited on-site treatment currently occurring generally consists of injection into disposal wells.[114] Other options would be dependent upon the nature and composition of the residuals and would require site-specific consultation with the Department's Division of Solid and Hazardous Materials. Transportation would require a Part 364 Waste Transporters' Permit.

5.14 Well Cleanup and Testing

Wells are typically tested after drilling and stimulation to determine their productivity, economic viability, and design criteria for a pipeline gathering system if one needs to be constructed. If no gathering line exists, well testing necessitates that produced gas be flared. However, operators have reported that for Marcellus Shale development in the northern tier of Pennsylvania, flaring is minimized by construction of the gathering system ahead of well completion. Flaring is necessary during the initial 12 to 24 hours of flowback operations while the well is producing a high ratio of flowback water to gas, but no flow testing that requires an extended period of flaring is conducted. Operators report that without a gathering line in place, initial cleanup or testing that could require flaring could last for 3 to 30 days.

5.15 Summary of Operations Prior to Production

Table 5.15 summarizes the primary operations that may take place at a multi-well pad prior to the production phase, and their typical durations. This tabulation assumes that a smaller rig is used to drill the vertical wellbore and a larger rig is used for the horizontal wellbore. Rig availability and other parameters outside the operators' control may affect the listed time frames. As explained in Section 5.2, no more than two rigs would operate on the well pad concurrently.

Note that the early production phase at a pad may overlap with the activities summarized in Table 5.15, as some wells may be placed into production prior to drilling and completion of all the wells on a pad. All pre-production operations for an entire pad must be concluded within three years or less, in accordance with ECL §23-0501. Estimated duration of each operation may be shorter or longer depending on site specific circumstances.

[114] URS, p. 5-3.

Table 5-15 - Primary Pre-Production Well Pad Operations

Operation	Materials and Equipment	Activities	Duration
Access Road and Well Pad Construction	Backhoes, bulldozers and other types of earth-moving equipment.	Clearing, grading, pit construction, placement of road materials such as geotextile and gravel.	Up to 4 weeks per well pad
Vertical Drilling with Smaller Rig	Drilling rig, fuel tank, pipe racks, well control equipment, personnel vehicles, associated outbuildings, delivery trucks.	Drilling, running and cementing surface casing, truck trips for delivery of equipment and cement. Delivery of equipment for horizontal drilling may commence during late stages of vertical drilling.	Up to 2 weeks per well; one to two wells at a time
Preparation for Horizontal Drilling with Larger Rig		Transport, assembly and setup, or repositioning on site of large rig and ancillary equipment.	5 – 30 days per well[115]
Horizontal Drilling	Drilling rig, mud system (pumps, tanks, solids control, gas separator), fuel tank, well control equipment, personnel vehicles, associated outbuildings, delivery trucks.	Drilling, running and cementing production casing, truck trips for delivery of equipment and cement. Deliveries associated with hydraulic fracturing may commence during late stages of horizontal drilling.	Up to 2 weeks per well; one to two wells at a time
Preparation for Hydraulic Fracturing		Rig down and removal or repositioning of drilling equipment. Truck trips for delivery of temporary tanks, water, sand, additives and other fracturing equipment. Deliveries may commence during late stages of horizontal drilling.	30 – 60 days per well, or per well pad if all wells treated during one mobilization
Hydraulic Fracturing Procedure	Temporary water tanks, generators, pumps, sand trucks, additive delivery trucks and containers (see Section 5.6.1), blending unit, personnel vehicles, associated outbuildings, including computerized monitoring equipment.	Fluid pumping, and use of wireline equipment between pumping stages to raise and lower tools used for downhole well preparation and measurements. Computerized monitoring. Continued water and additive delivery.	2 – 5 days per well, including approximately 40 to 100 hours of actual pumping
Fluid Return (“Flowback”) and Treatment	Gas/water separator, flare stack, temporary water tanks, mobile water treatment units, trucks for fluid removal if necessary, personnel vehicles.	Rig down and removal or repositioning of fracturing equipment; controlled fluid flow into treating equipment, tanks, lined pits, impoundments or pipelines; truck trips to remove fluid if not stored on site or removed by pipeline.	2 – 8 weeks per well, may occur concurrently for several wells
Waste Disposal	Earth-moving equipment, pump trucks, waste transport trucks.	Pumping and excavation to empty/reclaim reserve pit(s). Truck trips to transfer waste to disposal facility.	Up to 6 weeks per well pad

[115] The shorter end of the time frame for drilling preparations applies if the rig is already at the well pad and only needs to be repositioned. The longer end applies if the rig must be brought from off-site and is proportional to the distance which the rig must be moved. This time frame will occur prior to vertical drilling if the same rig is used for the vertical and horizontal portions of the wellbore.

Operation	Materials and Equipment	Activities	Duration
		Truck trips to remove temporary water storage tanks.	
Well Cleanup and Testing	Well head, flare stack, brine tanks. Earth-moving equipment.	Well flaring and monitoring. Truck trips to empty brine tanks. Gathering line construction may commence if not done in advance.	½ - 30 days per well

5.16 Natural Gas Production

5.16.1 Partial Site Reclamation

Subsequent to drilling and fracturing operations, associated equipment is removed. Any pits used for those operations must be reclaimed and the site must be re-graded and seeded to the extent feasible to match it to the adjacent terrain. Department inspectors visit the site to confirm full restoration of areas not needed for production.

Well pad size during the production phase will be influenced on a site-specific basis by topography and generally by the space needed to support production activities and well servicing. According to operators, multi-well pads will range between one and three acres in size during the production phase, after partial reclamation.

5.16.2 Gas Composition

5.16.2.1 Hydrocarbons

As discussed in Chapter 4 and shown on the maps accompanying the discussion in that section, most of the Utica Shale and most of the Marcellus Shale "fairway" are in the dry gas window as defined by thermal maturity and vitrinite reflectance. In other words, the shales would not be expected to produce liquid hydrocarbons such as oil or condensate. This is corroborated by gas composition analyses provided by one operator for wells in the northern tier of Pennsylvania and shown in Table 5.16.

Table 5-16 - Marcellus Gas Composition from Bradford County, PA

Mole percent samples from Bradford Co., PA												
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

Mole percent samples from Bradford Co., PA												
Sample Number	Nitrogen	Carbon Dioxide	Methane	Ethane	Propane	i-Butane	n-Butane	i-Pentane	n-Pentane	Hexanes +	Oxygen	sum
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

ICF International, reviewing the above data under contract to NYSERDA, notes that 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 not expected. [116] BTEX would normally be trapped in liquid phase with other components like natural gas liquids, oil or water. Fortuna Energy reports that it has sampled for benzene, toluene, and xylene and has not detected it in its gas samples or water analyses.

5.16.2.2 Hydrogen Sulfide

As further reported by ICF, sample number 1 in Table 5.16 included a sulfur analysis and found less than 0.032 grams sulfur per 100 cubic feet. The other samples did not include sulfur analysis. Chesapeake Energy reports that, to date, no hydrogen sulfide has been detected at any of its active interconnects in Pennsylvania. Fortuna Energy reports testing for hydrogen sulfide regularly with readings of 2 to 4 parts per million during a brief period on one occasion in its vertical Marcellus wells, and its presence has not reoccurred since.

5.16.3 Production Rate

Production rates are difficult to predict accurately for a play that has not yet been developed or is in the very early stages of development. One operator has indicated that its Marcellus production facility design will have a maximum capacity of either 6 MMcf per day or 10 MMcf per day,

[116] ICF Task 2, pp. 29-30.

whichever is appropriate. Another operator postulated long-term production for a single Marcellus well in New York as follows:

- Year 1 – Initial rate of 2.8 MMcf/d declining to 900 Mcf/d.
- Years 2 to 4 – 900 Mcf/d declining to 550 Mcf/d.
- Years 5 to 10 – 550 Mcf/d declining to 225 Mcf/d
- Year 11 and after – 225 Mcf/d declining at 3% per annum

5.16.4 Well Pad Production Equipment

In addition to the assembly of pressure-control devices and valves at the top of the well known as the "wellhead," "production tree" or "Christmas tree," equipment at the well pad during the production phase will likely include:

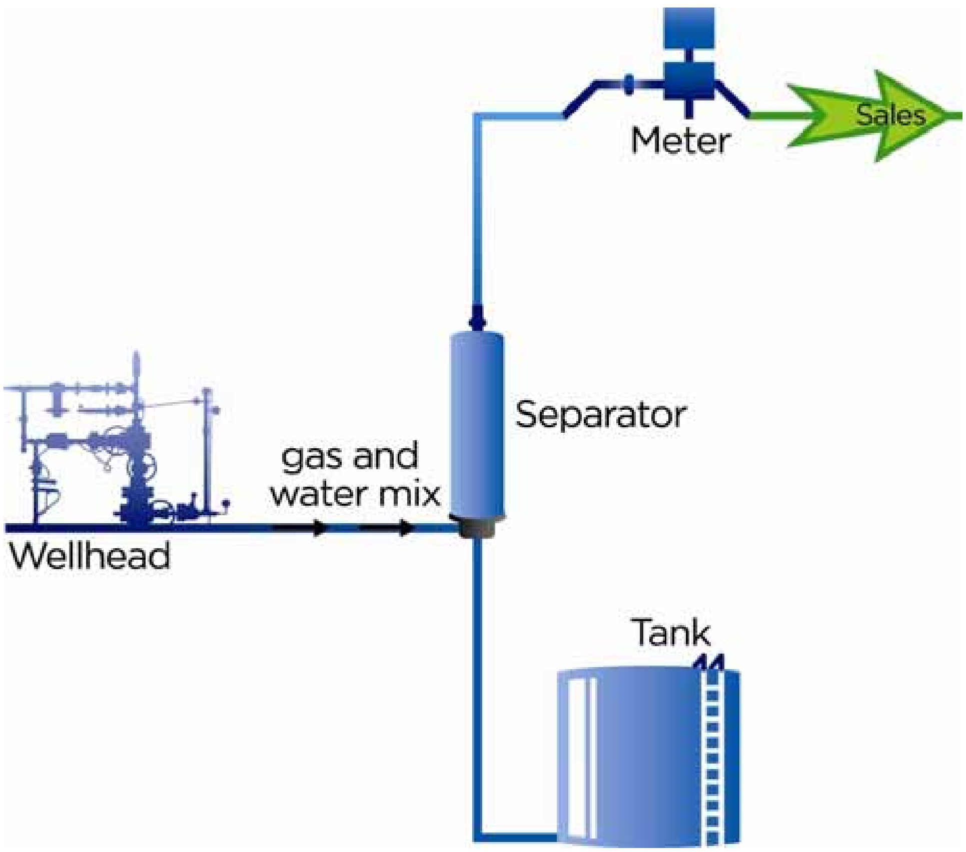
- A small inline heater that is in use for the first 6 to 8 months of production and during winter months to ensure freezing does not occur in the flow line due to Joule-Thompson effect (each well or shared),
- A two-phase gas/water separator,
- Gas metering devices (each well or shared),
- Water metering devices (each well or shared) and
- Brine storage tanks (shared by all wells).

In addition:

- A well head compressor may be added during later years after gas production has declined and
- A triethylene glycol (TEG) dehydrator may be located at some well sites, although typically the gas is sent to a gathering system for compression and dehydration at a compressor station.

Produced gas flows from the wellhead to the separator through a two- to three-inch diameter pipe ("flow line"). The operating pressure in the separator will typically be in the 100 to 200 psi range depending on the stage of the wells' life. At the separator, water will be removed from the gas stream via a dump valve and sent by pipe ("water line") to the brine storage tanks. The gas continues through a meter and to the departing gathering line, which carries the gas to a centralized compression facility. See Figure 5.6.

Figure 5-6 - Simplified Illustration of Gas Production Process



5.16.5 Brine Storage

Based on experience to date in the northern tier of Pennsylvania, one operator reports that brine production has typically been less than 10 barrels per day after the initial flowback operation and once the well is producing gas. Another operator reports that the rate of brine production during the production phase is about to 5 - 20 barrels per million cubic feet of gas produced.

One or more brine tanks will be installed on-site, along with truck loading facilities. At least one operator has indicated the possibility of constructing pipelines to move brine from the site, in which case truck loading facilities would not be necessary. Operators monitor brine levels in the tanks at least daily, with some sites monitored remotely by telemetric devices capable of sending alarms or shutting wells in if the storage limit is approached.

The storage of production brine in on-site pits has been prohibited in New York since 1984.

5.16.6 Brine Disposal

Production brine disposal options include injection wells, treatment plants and road spreading for dust control and deicing, which are all discussed in the GEIS. If produced water is trucked off-site, it must be hauled by approved Part 364 Waste Transporters.

With respect to road spreading, in January 2009 DEC's Division of Solid and Hazardous Materials ("DSHM"), responsible for oversight of the Part 364 Waste Transporter program, released a notification to haulers applying for, modifying, or renewing their Part 364 permits that any entity applying for a Part 364 permit or permit modification to use production fluid for road spreading must submit a petition for a beneficial use determination ("BUD") to the Department. The BUD and Part 364 permit must be issued by the Department prior to any production brine being removed from a well site for road spreading. See Appendix 12 for the notification.

5.16.7 Naturally Occurring Radioactive Materials in Marcellus Production Brine

Results of the Department's initial NORM analysis of Marcellus brine produced in New York are shown in Appendix 13. These samples were collected in late 2008 and 2009 from vertical gas wells in the Marcellus formation. The data indicate the need to collect additional samples of production brine to assess the need for mitigation and to require appropriate handling and treatment options, including possible radioactive materials licensing. Potential impacts and proposed mitigation measures related to NORM are discussed in Chapters 6 and 7.

5.16.8 Gas Gathering and Compression

Operators report a 0.55 psi/foot to 0.60 psi/foot pressure gradient for the Marcellus Shale in the northern tier of Pennsylvania. Bottom-hole pressure equals the depth of the well times the pressure gradient. Therefore, the bottom-hole pressure on a 6,000-foot deep well will be between 3,300 and 3,600 psi. Wellhead pressures would be lower, depending on the makeup of the gas. One operator reported flowing tubing pressures in Bradford County, Pennsylvania, of 1,100 to 2,000 psi. Gas flowing at these pressures would not initially require compression to flow into a transmission line. Pressure decreases over time, however, and one operator stated an advantage of flowing the wells at as low a pressure as economically practical from the outset, to take advantage of the shale's gas desorption properties. In either case, the necessary compression to allow gas to flow into a large transmission line for sale would typically occur at a centralized site. Dehydration units, to remove water vapor from the gas before it flows into the sales line, would also be located at the centralized compression facilities.

Based on experience in the northern tier of Pennsylvania, operators estimate that a centralized facility will service well pads within a four to six mile radius. The gathering system from the well to a centralized compression facility consists of buried PVC or steel pipe, and the buried lines leaving the compression facility consists of coated steel.

Siting of gas gathering and pipeline systems, including the centralized compressor stations described above, is not subject to SEQRA review. See 6 NYCRR 617.5(c)(35). Therefore, the above description of these facilities, and the following description of the Public Service Commission's environmental review process, are presented for informational purposes only. This SGEIS will not result in SEQRA findings or new SEQRA procedures regarding the siting and approval of gas gathering and pipeline systems or centralized compression facilities.

Photo 5.28 shows an aerial view of a compression facility.

Photo 5.28 - Pipeline Compressor in New York. Source: Fortuna Energy

5.16.8.1 Regulation of Gas Gathering and Pipeline Systems

Article VII, "Siting of Major Utility Transmission Facilities," is the section of the New York Public Service Law (PSL) that requires a full environmental impact review of the siting, design, construction, and operation of major intrastate electric and natural gas transmission facilities in New York State. The Public Service Commission (Commission or PSC) has approval authority over actions involving intrastate electric power transmission lines and high pressure natural fuel gas pipelines, and actions related to such projects. An example of an action related to a high pressure natural fuel gas pipeline is the siting and construction of an associated compressor station. While DEC and other agencies can have input into the review of an Article VII application or Notice of Intent (NOI) for an action, and can process ancillary permits for federally delegated programs, the ultimate decision on a given project application is made by the

Commission. The review and permitting process for natural fuel gas pipelines is separate and distinct from that used by the DEC to review and permit well drilling applications under ECL Article 23, and is traditionally conducted after a well is drilled, tested and found productive. For development and environmental reasons, along with anticipated success rates, it has been suggested that wells targeting the Marcellus shale and other low-permeability gas reservoirs using horizontal drilling and high-volume hydraulic fracturing may deserve consideration of pipeline certification by the PSC in advance of drilling to allow pipelines to be in place and operational at the time of the completion of the wells.

The PSC's statutory authority has its own "SEQR-like" review, record, and decision standards that apply to major gas and electric transmission lines. As mentioned above, PSC makes the final decision on Article VII applications. Article VII supersedes other State and local permits except for federally authorized permits; however, Article VII establishes the forum in which community residents can participate with members of State and local agencies in the review process to ensure that the application comports with the substance of State and local laws. Throughout the Article VII review process, applicants are strongly encouraged to follow a public information process designed to involve the public in a project's review. Article VII includes major utility transmission facilities involving both electricity and fuel gas (natural gas), but the following discussion, which is largely derived from PSC's guide entitled "The Certification Review Process for Major Electric and Fuel Gas Transmission Facilities," [117] is focused on the latter. While the focus of PSC's guide with respect to natural gas is the regulation and permitting of transmission lines at least ten miles long and operated at a pressure of 125 psig or greater, the certification process explained in the guide and outlined below provides the basis for the permitting of transmission lines less than ten miles long that will typically serve Marcellus Shale and other low-permeability gas reservoir wells.

Public Service Commission

PSC is the five member decision-making body established by PSL § 4 that regulates investor-owned electric, natural gas, steam, telecommunications, and water utilities in New York State.

[117] http://www.dps.state.ny.us/Article_VII_Process_Guide.pdf

The Commission, made up of a Chairman and four Commissioners, decides any application filed under Article VII. The Chairman of the Commission, designated by the Governor, is also the chief executive officer of the Department of Public Service (DPS). Employees of the DPS serve as staff to the PSC.

DPS is the State agency that serves to carry out the PSC's legal mandates. One of DPS's responsibilities is to participate in all Article VII proceedings to represent the public interest. DPS employs a wide range of experts, including planners, landscape architects, foresters, aquatic and terrestrial ecologists, engineers, and economists, who analyze environmental, engineering, and safety issues, as well as the public need for a facility proposed under Article VII. These professionals take a broad, objective view of any proposal, and consider the project's effects on local residents, as well as the needs of the general public of New York State. Public participation specialists monitor public involvement in Article VII cases and are available for consultation with both applicants and stakeholders.

Article VII

The New York State Legislature enacted Article VII of the PSL in 1970 to establish a single forum for reviewing the public need for, and environmental impact of, certain major electric and gas transmission facilities. The PSL requires that an applicant must apply for a Certificate of Environmental Compatibility and Public Need (Certificate) and meet the Article VII requirements before constructing any such intrastate facility. Article VII sets forth a review process for the consideration of any application to construct and operate a major utility transmission facility. Natural fuel gas transmission lines originating at wells are commonly referred to as "gathering lines" because the lines may collect or gather gas from a single or number of wells which feed a centralized compression facility or other transmission line. The drilling of multiple Marcellus Shale or other low-permeability gas reservoir wells from a single well pad and subsequent production of the wells into one large diameter gathering line eliminates the need for construction and associated cumulative impacts from individual gathering lines if traditionally drilled as one well per location. The PSL defines major natural gas transmission facilities, which statutorily includes many gathering lines, as pipelines extending a distance of at least 1,000 feet and operated at a pressure of 125 psig or more, except where such natural gas pipelines:

- are located wholly underground in a city, or
- are located wholly within the right-of-way of a State, county or town highway or village street, or
- replace an existing transmission facility, and are less than one mile long.

Under 6 NYCRR § 617.5(c)(35), actions requiring a Certificate of Environmental Compatibility and Public Need under article VII of the PSL and the consideration of, granting or denial of any such Certificate are classified as "Type II" actions for the purpose of SEQR. Type II actions are those actions, or classes of actions, which have been found categorically to not have significant adverse impacts on the environment, or actions that have been statutorily exempted from SEQR review. Type II actions do not require preparation of an EAF, a negative or positive declaration, or an environmental impact statement (EIS) under SEQR. Despite the legal exemption from processing under SEQR, as previously noted, Article VII contains its own process to evaluate environmental and public safety issues and potential impacts, and impose mitigation measures as appropriate.

As explained in the GEIS, and shown in Table 5.17, PSC has siting jurisdiction over all lines operating at a pressure of 125 psig or more and at least 1,000 feet in length, and siting jurisdiction of lines below these thresholds if such lines are part of a larger project under PSC's purview. In addition, PSC's safety jurisdiction covers all natural gas gathering lines and pipelines regardless of operating pressure and line length. PSC's authority, at the well site, physically begins at the well's separator outlet. DEC's permitting authority over gathering lines operating at pressures less than 125 psig primarily focuses on the permitting of disturbances in environmentally sensitive areas, such as streams and wetlands, and the DEC is responsible for administering federally delegated permitting programs involving air and water resources. For all other pipelines regulated by the PSC, the DEC's jurisdiction is limited to the permitting of certain federally delegated programs involving air and water resources. Nevertheless, in all instances, the DEC either directly imposes mitigation measures through its permits or provides comments to the PSC which, in turn, routinely requires mitigation measures to protect environmentally sensitive areas.

Pre-Application Process

Early in the planning phase of a project, the prospective Article VII applicant is encouraged to consult informally with stakeholders. Before an application is filed, stakeholders may obtain information about a specific project by contacting the applicant directly and asking the applicant to put their names and addresses on the applicant's mailing list to receive notices of public information meetings, along with project updates. After an application is filed, stakeholders may request their names and addresses be included on a project "service list" which is maintained by the PSC. Sending a written request to the Secretary to the PSC to be placed on the service list for a case will allow stakeholders to receive copies of orders, notices and rulings in the case. Such requests should reference the Article VII case number assigned to the application.

Table 5-17 - Intrastate Pipeline Regulation[118]

PIPELINE TYPE	DEC	PSC
Gathering <125 psig	Siting jurisdiction only in environmentally sensitive areas where DEC permits, other than the well permit, are required. Permitting authority for federally delegated programs such as Title V of the Clean Air Act (i.e., major stationary sources) and Clean Water Act National Pollutant Discharge Elimination System program (i.e., SPDES General Permit for Stormwater Discharges).	Safety jurisdiction. Public Service Law § 66, 16 NYCRR § 255.9 and Appendix 7-G(a)**.
Gathering ≥125 psig, <1,000 ft.	Permitting authority for certain federally delegated programs such as Title V of the Clean Air Act (i.e., major stationary sources) and Clean Water Act National Pollutant Discharge Elimination System program (i.e., SPDES General Permit for Stormwater Discharges).	Safety jurisdiction. Public Service Law § 66, 16 NYCRR § 255.9 and Appendix 7-G(a)**. Siting jurisdiction also applies if part of larger system subject to siting review. Public Service Law § 66, 16 NYCRR Subpart 85-1.4.
Fuel Gas Transmission* ≥125 psig, ≤1,000 ft., <5 mi., ≤6 in. diameter	Permitting authority for certain federally delegated programs such as Title V of the Clean Air Act (i.e., major stationary sources) and Clean Water Act National Pollutant Discharge Elimination System program (i.e., SPDES General Permit for Stormwater Discharges).	Siting and safety jurisdiction. Public Service Law Sub-Article VII § 121a-2, 16 NYCRR § 255.9 and Appendices 7-D, 7-G and 7-G(a)**. 16 NYCRR Subpart 85-1. EM&CS&P*** checklist must be filed. Service of NOI or application to other agencies required.

[118] Adapted from the 1992 GEIS.

PIPELINE TYPE	DEC	PSC
Fuel Gas Transmission* ≥125 psig, ≥5 mi., <10 mi. Note: The pipelines associated with wells being considered in this document typically fall into this category, or possibly the one above.	Permitting authority for certain federally delegated programs such as Title V of the Clean Air Act (i.e., major stationary sources) and Clean Water Act National Pollutant Discharge Elimination System program (i.e., SPDES General Permit for Stormwater Discharges).	Siting and safety jurisdiction. Public Service Law Sub-Article VII § 121a-2, 16 NYCRR § 255.9 and Appendices 7-D, 7-G and 7-G(a)**. 16 NYCRR Subpart 85-1. EM&CS&P*** checklist must be filed. Service of NOI or application to other agencies required.
Fuel Gas Transmission* ≥125 psig, ≥10 mi.	Permitting authority for certain federally delegated programs such as Title V of the Clean Air Act (i.e., major stationary sources) and Clean Water Act National Pollutant Discharge Elimination System program (i.e., SPDES General Permit for Stormwater Discharges).	Siting and safety jurisdiction. Public Service Law Article VII § 120, 16 NYCRR § 255.9, 16 NYCRR Subpart 85-2. Environmental assessment must be filed. Service of application to other agencies required.
* Federal Minimum Pipeline Safety Standards 49 CFR Part 192 supersedes PSC if line is closer than 150 ft. to a residence or in an urban area. ** Appendix 7-G(a) is required in all active farm lands. *** EM&CS&P means Environmental Management and Construction Standards and Practices.		

Application

An Article VII application must contain the following information:

- location of the line and right-of-way,
- description of the transmission facility being proposed,
- summary of any studies made of the environmental impact of the facility, and a description of such studies,
- statement explaining the need for the facility,
- description of any reasonable alternate route(s), including a description of the merits and detriments of each route submitted, and the reasons why the primary proposed route is best suited for the facility; and,
- such information as the applicant may consider relevant or the Commission may require.

In an application, the applicant is also encouraged to detail its public involvement activities and its plans to encourage public participation. DPS staff takes about 30 days after an application is filed to determine if the application is in compliance with Article VII filing requirements. If an application lacks required information, the applicant is informed of the deficiencies. The applicant can then file supplemental information. If the applicant chooses to file the supplemental information, the application is again reviewed by the DPS for a compliance determination. Once an application for a Certificate is filed with the PSC, no local municipality or other State agency may require any hearings or permits concerning the proposed facility.

Timing of Application & Pipeline Construction

The extraction of projected economically recoverable reserves from the Marcellus Shale, and other low-permeability gas reservoirs, presents a unique challenge and opportunity with respect to the timing of an application and ultimate construction of the pipeline facilities necessary to tie this gas source into the transportation system and bring the produced gas to market. In the course of developing other gas formations, the typical sequence of events begins with the operator first drilling a well to determine its productivity and, if successful, then submitting an Article VII application for PSC approval to construct the associated pipeline. This reflects the risk associated with conventional oil and gas exploration where finding natural gas in paying quantities is not guaranteed.

The typical procedure of drilling wells, testing wells by flaring and then constructing gathering lines may not be ideally suited for the development of the Marcellus Shale and other low permeability reservoirs. To date, the success rate of horizontally drilled and hydraulically fractured Marcellus Shale wells in neighboring Pennsylvania and West Virginia, as reported by three companies, is one hundred percent for 44 wells drilled.[119] This rate of success is apparently due primarily to the fact that the Marcellus Shale reservoir appears to contain natural gas in sufficient quantities which can be produced using horizontal drilling and high-volume hydraulic fracturing technology. All gathering lines constructed prior to Marcellus Shale well drilling in the above referenced states have been put into operation and are serving their intended purpose. It is highly unlikely that an operator in New York would make a substantial investment in a pipeline ahead of completing a well unless there is an extremely high probability of finding gas in suitable quantities and at viable flowrates.

In addition, the Marcellus Shale formation has a high concentration of clay that is sensitive to fresh water contact which makes the formation susceptible to re-closing if the flowback fluid and natural gas do not flow immediately after hydraulic fracturing operations. The horizontal drilling and hydraulic fracturing technique used to tap into the Marcellus requires that the well be flowed back and gas produced immediately after the well has been fractured and completed, otherwise the formation may be damaged and the well may cease to be economically productive. In

[119] Chesapeake Energy Corp., Fortuna Energy Inc., Seneca Resources Corp.

addition to enhancing the completion by preventing formation damage, having a pipeline in place when a well is initially flowed would reduce the amount of gas flared to the atmosphere during initial recovery operations. This type of completion with limited or no flaring is sometimes referred to as a "green" or reduced emissions completion (REC). To combat formation damage during hydraulic fracturing with conventional fluids, a new and alternative hydraulic fracturing technology recently entered the Canadian market and was also used in Pennsylvania in September 2009. It uses liquefied petroleum gas (LPG), consisting mostly of propane in place of water-based hydraulic fracturing fluids. Using propane not only minimizes formation damage, but also eliminates the need to source water for hydraulic fracturing, recover flowback fluids to the surface and dispose of the flowback fluids.[120] While it's unknown if and when LPG hydraulic fracturing will be proposed in New York, having gathering infrastructure in place, would allow the propane to be recovered during flowback directly to a pipeline along with the produced natural gas.

Also, if installed prior to well drilling, an in-place gas production pipeline could serve a second purpose and be used initially to transport fresh water or recycled hydraulic fracturing fluids to the well site for use in hydraulic fracturing the first well on the pad, or for transport of fluids to a centralized impoundment. This in itself would reduce or eliminate other fluid transportation options, such as trucking and construction of a separate fluid pipeline, and associated impacts. Because of the many potential benefits noted above, which have been demonstrated in other states, it has been suggested that New York should have the option to certify and build pipelines in advance of well drilling targeting the Marcellus Shale and other low-permeability gas reservoirs.

Filing and Notice Requirements

Article VII requires that a copy of an application for a transmission line ten miles or longer in length be provided by the applicant to the DEC, the Department of Economic Development, the Secretary of State, the Department of Agriculture and Markets and the Office of Parks, Recreation and Historic Preservation, and each municipality in which any portion of the facility

[120] Smith, 2008. *FRACforward, Startup Cracks Propane Fracture Puzzle, Provides 'Green' Solution*, Nickle's New Technology Magazine, www.ntm.nickles.com

is proposed to be located. This is done for both the primary route proposed and any alternative locations listed. A copy of the application must also be provided to the State legislators whose districts the proposed primary facility or any alternative locations listed would pass through. Service requirements for transmission lines less than 10 miles in length are slightly different but nevertheless comprehensive.

An Article VII application for a transmission line ten miles or longer in length must be accompanied by proof that notice was published in a newspaper(s) of general circulation in all areas through which the facility is proposed to pass, for both its primary and alternate routes. The notice must contain a brief description of the proposed facility and its proposed location, along with a discussion of reasonable alternative locations. An applicant is not required to provide copies of the application or notice of the filing of the application to individual property owners of land on which a portion of either the primary or alternative route is proposed. However, to help foster public involvement, an applicant is encouraged to do so.

Party Status in the Certification Proceeding

Article VII specifies that the applicant and certain State and municipal agencies are parties in any case. The DEC and the Department of Agriculture & Markets are among the statutorily named parties and usually actively participate. Any municipality through which a portion of the proposed facility will pass, or any resident of such municipality, may also become a formal party to the proceeding. Obtaining party status enables a person or group to submit testimony, cross-examine witnesses of other parties and file briefs in the case. Being a party also entails the responsibility to send copies of all materials filed in the case to all other parties. DPS staff participates in all Article VII cases as a party, in the same way as any other person who takes an active part in the proceedings.

The Certification Process

Once all of the information needed to complete an application is submitted and the application is determined to be in compliance, review of the application begins. In a case where a hearing is held, the Commission's Office of Hearings and Alternative Dispute Resolution provides an Administrative Law Judge (ALJ) to preside in the case. The ALJ is independent of DPS staff and other parties and conducts public statement and evidentiary hearings and rules on procedural matters. Hearings help the Commission decide whether the construction and operation of new transmission facilities will fulfill the public need, be compatible with environmental values and the public health and safety, and comply with legal requirements. After considering all the evidence presented in a case, the ALJ usually makes a recommendation for the Commission's consideration.

Commission Decision

The Commission reviews the ALJ's recommendation, if there is one, and considers the views of the applicant, DPS staff, other governmental agencies, organizations, and the general public, received in writing, orally at hearings or at any time in the case. To grant a Certificate, either as proposed or modified, the Commission must determine all of the following:

1. the need for the facility,
2. the nature of the probable environmental impact,
3. the extent to which the facility minimizes adverse environmental impact, given environmental and other pertinent considerations,
4. that the facility location will not pose undue hazard to persons or property along the line,
5. that the location conforms with applicable State and local laws; and,
6. the construction and operation of the facility is in the public interest.

Following Article VII certification, the Commission typically requires the certificate holder to submit various additional documents to verify its compliance with the certification order. One of the more notable compliance documents, an Environmental Management and Construction Plan (EM&CP), must be approved by the Commission before construction can begin. The EM&CP details the precise field location of the facilities and the special precautions that will be taken during construction to ensure environmental compatibility. The EM&CP must also indicate the practices to be followed to ensure that the facility is constructed in compliance with applicable safety codes and the measures to be employed in maintaining and operating the facility once it is constructed. Once the Commission is satisfied that the detailed plans are consistent with its decision and are appropriate to the circumstances, it will authorize commencement of construction. DPS staff is then responsible for checking the applicant's practices in the field.

Amended Certification Process

In 1981, the Legislature amended Article VII to streamline procedures and application requirements for the certification of fuel gas transmission facilities operating at 125 psig or more, and that extend at least 1,000 feet, but less than ten miles. The pipelines or gathering lines associated with wells being considered in this document typically fall into this category, and, consequently, a relatively expedited certification process occurs that is intended to be no less protective. The updated requirements mimic those described above with notable differences being: 1) a NOI may be filed instead of an application, 2) there is no mandatory hearing with testimony or required notice in newspaper, and 3) the PSC is required to act within thirty or sixty days depending upon the size and length of the pipeline.

The updated requirements applicable to such fuel gas transmission facilities are set forth in PSL Section 121-a and 16 NYCRR Sub-part 85-1. All proposed pipeline locations are verified and walked in the field by DPS staff as part of the review process, and staff from the DEC and Department of Agriculture & Markets may participate in field visits as necessary. As mentioned above, these departments normally become active parties in the NOI or application review process and usually provide comments to DPS staff for consideration. Typical comments from DEC and Agriculture and Markets relate to the protection of agricultural lands, streams, wetlands, rare or state-listed animals and plants, and significant natural communities and habitats.

Instead of an applicant preparing its own environmental management and construction standards and practices (EM&CS&P), it may choose to rely on a PSC approved set of standards and practices, the most comprehensive of which was prepared by DPS staff in February 2006.[121] The DPS authored EM&CS&P was written primarily to address construction of smaller-scale fuel gas transmission projects envisioned by PSL Section 121-a that will be used to transport gas from the wells being considered in this document. Comprehensive planning and construction management are key to minimizing adverse environmental impacts of pipelines and their construction. The EM&CS&P is a tool for minimizing such impacts of fuel gas transmission

[121] DPS, 2006. *Environmental Management and Construction Standards and Practices for Underground Transmission and Distribution Facilities in New York State*, Office of Electricity & Environment, Albany, NY.

pipelines reviewed under the PSL. The standards and practices contained in the 2006 EM&CS&P handbook are intended to cover the range of construction conditions typically encountered in constructing pipelines in New York.

The pre-approved nature of the 2006 EM&CS&P supports a more efficient submittal and review process, and aids with the processing of an application or NOI within mandated time frames. The measures from the EM&CS&P that will be used in a particular project must be identified on a checklist and included in the NOI or application. A sample checklist is included as Appendix 14, which details the extensive list of standards and practices considered in DPS's EM&CS&P and readily available to the applicant. Additionally, the applicant must indicate and include any measures or techniques it intends to modify or substitute for those included in the PSC approved EM&CS&P.

An important measure specified in the EM&CS&P checklist is a requirement for supervision and inspection during various phases of the project. Page four of the 2006 EM&CS&P states "At least one Environmental Inspector (EI) is required for each construction spread during construction and restoration. The number and experience of EIs should be appropriate for the length of the construction spread and number/significance or resources affected." The 2006 EM&CS&P also requires that the name(s) of qualified Environmental Inspector(s) and a statement(s) of the individual's relative project experience be provided to the DPS prior to the start of construction for DPS staff's review and acceptance. Another important aspect of the PSC approved EM&CS&P is that Environmental Inspectors have stop-work authority entitling the EI to stop activities that violate Certificate conditions or other federal, State, local or landowner requirements, and to order appropriate corrective action.

Conclusion

Whether an applicant submits an Article VII application or Notice of Intent as allowed by the Public Service Law, the end result is that all Public Service Commission issued Certificates of Environmental Compatibility and Public Need for fuel gas transmission lines contain ordering clauses, stipulations and other conditions that the Certificate holder must comply with as a condition of acceptance of the Certificate. Many of the Certificate's terms and conditions relate to environmental protection. The Certificate holder is fully expected to comply with all of the terms and conditions or it may face an enforcement action. Department of Public Service staff monitor construction activities to help ensure compliance with the Commission's orders. After installation and pressure testing of a pipeline, its operation, monitoring, maintenance and eventual abandonment must also be conducted in accordance with and adhere to the provisions of the Certificate and New York State law and regulations.

5.17 Well Plugging

As described in the GEIS, any unsuccessful well or well whose productive life is over must be properly plugged and abandoned, in accordance with Department-issued plugging permits and under the oversight of Department field inspectors. Proper plugging is critical for the continued protection of groundwater, surface water bodies and soil. Financial security to ensure funds for well plugging is required before the permit to drill is issued, and must be maintained for the life of the well.

When a well is plugged, downhole equipment is removed from the wellbore, uncemented casing in critical areas must be either pulled or perforated, and cement must be placed across or squeezed at these intervals to ensure seals between hydrocarbon and water-bearing zones. These downhole cement plugs supplement the cement seal that already exists at least behind the surface (i.e., fresh-water protection) casing and above the completion zone behind production casing.

Intervals between plugs must be filled with a heavy mud or other approved fluid. For gas wells, in addition to the downhole cement plugs, a minimum of 50 feet of cement must be placed in the top of the wellbore to prevent any release or escape of hydrocarbons or brine from the wellbore. This plug also serves to prevent wellbore access from the surface, eliminating it as a safety hazard or disposal site.

Removal of all surface equipment and full site restoration are required after the well is plugged. Proper disposal of surface equipment includes testing for NORM to determine the appropriate disposal site.

The plugging requirements summarized above are described in detail in Chapter 11 of the GEIS and are enforced as conditions on plugging permits. Issuance of plugging permits is classified as a Type II action under SEQRA. Proper well plugging is a beneficial action with the sole purpose of environmental protection, and constitutes a routine agency action. Horizontal drilling and high-volume hydraulic fracturing do not necessitate any new or different methods for well plugging that require further SEQRA review.

5.18 Other States' Regulations

The Department committed in Section 2.1.2 of the Final Scope for this SGEIS to evaluate the effectiveness of other states' regulations with respect to hydraulic fracturing and to consider the advisability of adopting additional protective measures based on those that have proven successful in other states for similar activities. Department staff consulted the following sources to conduct this evaluation:

1) *Ground Water Protection Council, 2009b.* The Ground Water Protection Council (GWPC) is an association of ground water and underground injection control regulators. In May 2009, GWPC reported on its review of the regulations of 27 oil and gas producing states. The stated purpose of the review was to evaluate how the regulations relate to direct protection of water resources.

2) *ICF International, 2009a.* NYSERDA contracted ICF International to conduct a regulatory analysis of New York and up to four other shale gas states regarding notification, application, review and approval of hydraulic fracturing and re-fracturing operations. ICF's review included Arkansas (Fayetteville Shale), Louisiana (Haynesville Shale), Pennsylvania (Marcellus Shale) and Texas (Barnett Shale).

3) *Alpha Environmental Consultants, Inc., 2009.* NYSERDA contracted Alpha Environmental Consultants, Inc., to survey policies, procedures, regulations and recent regulatory changes related to hydraulic fracturing in Pennsylvania, Colorado, New Mexico, Wyoming, Texas (including the City of Fort Worth), West Virginia, Louisiana, Ohio and Arkansas. Based on its review, Alpha summarized potential permit application requirements to evaluate well pad impacts and also provided recommendations for minimizing the likelihood and impact of liquid chemical spills that are reflected elsewhere in this SGEIS.

4) *Colorado Oil & Gas Conservation Commission, Final Amended Rules.* In the spring of 2009, the Colorado Oil & Gas Conservation Commission adopted new regulations regarding, among other things, the chemicals that are used at wellsites and public water supply protection. Colorado's program was included in Alpha's regulatory survey, but the amended rules' emphasis on topics pertinent to this SGEIS led staff to do a separate review of the regulations related to chemical use and public water supply buffer zones.

5) *June 2009 Statements on Hydraulic Fracturing from State Regulatory Officials.* On June 4, 2009, GWPC's president testified before Congress (i.e., the House Committee on Natural

Resources' Subcommittee on Energy and Mineral Resources) regarding hydraulic fracturing. Attached to his written testimony were letters from regulatory officials in Ohio, Pennsylvania, New Mexico, Alabama and Texas. These officials unanimously stated that no instances of ground water contamination attributable to hydraulic fracturing had been documented in their states. Also in June 2009, the Interstate Oil and Gas Compact Commission compiled and posted on its website statements from oil and gas regulators in 12 of its member states: Alabama, Alaska, Colorado, Indiana, Kentucky, Louisiana, Michigan, Oklahoma, Tennessee, Texas, South Dakota and Wyoming.[122] These officials also unanimously stated that no verified instances of harm to drinking water attributable to hydraulic fracturing had occurred in their states despite use of the process in thousands of wells over several decades. All 15 statements are included in Appendix 15.

Emphasis on proper well casing and cementing procedures is identified by GWPC and state regulators as the primary safeguard against ground water contamination during the hydraulic fracturing procedure. This approach has been effective, based on the regulatory statements summarized above and included in the Appendices. Improvements to casing and cementing requirements, along with enhanced requirements regarding other activities such as pit construction and maintenance, are appropriate responses to problems and concerns that arise as technologies advance. Chapters 7 and 8 of this SGEIS, on mitigation measures and the permit process, reflect consideration of any of those requirements regarding either hydraulic fracturing or ancillary activities in other states that (1) are more stringent than New York's and (2) address potential impacts associated with horizontal drilling and high-volume hydraulic fracturing that are not covered by the 1992 GEIS.

Additional information is provided below regarding the findings and conclusions expressed by GWPC, ICF and Alpha that are most relevant to the mitigation approach presented in this SGEIS. Pertinent sections of Colorado's final amended rules are also summarized.

5.18.1 Summary of GWPC's Review

GWPC's overall conclusion, based on its review of 27 states' regulations, including New York's, is that state oil and gas regulations are adequately designed to directly protect water resources. Hydraulic fracturing is one of eight topics reviewed. The other seven topics were permitting, well construction, temporary abandonment, well plugging, tanks, pits and waste handling/spills.

[122] http://www.iogcc.state.ok.us/hydraulic-fracturing

5.18.1.1 GWPC - Hydraulic Fracturing

With respect to the specific topic of hydraulic fracturing, GWPC found that states generally focus on well construction (i.e., casing and cement) and noted the importance of proper handling and disposal of materials. GWPC recommends identification of fracturing fluid additives and concentrations, as well as a higher level of scrutiny and protection for shallow hydraulic fracturing or when the target formation is in close proximity to underground sources of drinking water. GWPC did not provide thresholds for defining when hydraulic fracturing should be considered "shallow" or "in close proximity" to underground sources of drinking water. GWPC did not recommend additional controls on the actual conduct of the hydraulic fracturing procedure itself for deep non-coalbed methane wells that are not in close proximity to drinking water sources, nor did GWPC suggest any restrictions on fracture fluid composition for such wells.

GPWC urges caution against developing and implementing regulations based on anecdotal evidence alone, but does recommend continued investigation of complaints of ground water contamination to determine if a causal relationship to hydraulic fracturing can be established.

5.18.1.2 GWPC – Other Activities

Of the other seven topic areas reviewed by GWPC, permitting, well construction, tanks, pits and waste handling and spills are addressed by this SGEIS. GWPC's recommendations regarding each of these are summarized below.

Permitting

Unlike New York, in many states the oil and gas regulatory authority is a separate agency from other state-level environmental programs. GWPC recommends closer, more formalized cooperation in such instances. Another suggested action related to permitting is that states continue to expand use of electronic data management to track compliance, facilitate field inspections and otherwise acquire, store, share, extract and use environmental data.

Well Construction

GWPC recommends adequate surface casing and cement to protect ground water resources, adequate cement on production casing to prevent upward migration of fluids during all reservoir conditions, use of centralizers and the opportunity for state regulators to witness casing and cementing operations.

Tanks

Tanks, according to GWPC, should be constructed of materials suitable for their usage. Containment dikes should meet a permeability standard and the areas within containment dikes should be kept free of fluids except for a specified length of time after a tank release or a rainfall event.

Pits

GWPC's recommendations target "long-term storage pits." Permeability and construction standards for pit liners are recommended to prevent downward migration of fluids into ground water. Excavation should not be below the seasonal high water table. GPWC recommends against use of long-term storage pits where underlying bedrock contains seepage routes, solution features or springs. Construction requirements to prevent ingress and egress of fluids during a flood should be implemented within designated 100-year flood boundaries. Pit closure specifications should address disposition of fluids, solids and the pit liner. Finally, GWPC suggests prohibiting the use of long-term storage pits within the boundaries of public water supply and wellhead protection areas.

Waste Handling and Spills

In the area of waste handling, GWPC's suggests actions focused on surface discharge because "approximately 98% of all material generated . . . is produced water,"[123] and injection via disposal wells is highly regulated. Surface discharge should not occur without the issuance of an appropriate permit or authorization based on whether the discharge could enter water. As reflected in Colorado's recently amended rules, soil remediation in response to spills should be in accordance with a specific cleanup standard such as a Sodium Absorption Ratio (SAR) for salt-affected soil.

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[123] GWPC, 2009b. p. 30

5.18.2 ICF Findings

ICF concluded that regulatory procedures in all of the states reviewed, including New York, are sufficient to prevent fracturing fluid from flowing upward along the wellbore and contacting water-bearing strata adjacent to the borehole. ICF also concluded that, under specific conditions, "currently proposed approaches to hydraulic fracturing will not have reasonably foreseeable adverse environmental impacts on potential freshwater aquifers due to subsurface migration of fracturing fluids."[124] The conditions under which ICF's analysis supports this conclusion are:

- Maximum depth to the bottom of a potential aquifer ≤ 1,000 feet
- Minimum depth of the target fracture zone ≥ 2,000 feet
- Average hydraulic conductivity of intervening strata ≤ $1E^{-5}$ cm/sec
- Average porosity of intervening strata ≥ 10%

ICF states that "even under the combination of these conditions most favorable to flow, the pressures and volumes proposed for hydraulic fracturing are insufficient to cause migration of fluids from the fracture zone to the overlying aquifer in the short time that fracturing pressures would be applied. Conditions outside of these limits may require site-specific review."[125]

5.18.3 Summary of Alpha's Regulatory Survey

Topics reviewed by Alpha include: pit rules and specifications, reclamation and waste disposal, water well testing, fracturing fluid reporting requirements, hydraulic fracturing operations, fluid use and recycling, materials handling and transport, minimization of potential noise and lighting impacts, setbacks, multi-well pad reclamation practices, naturally occurring radioactive materials and stormwater runoff. Alpha supplemented its regulatory survey with discussion of practices directly observed during field visits to active Marcellus sites in the northern tier of Pennsylvania (Bradford County).

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[124] Ibid., p. 36

[125] ICF, 2009a

5.18.3.1 Alpha – Hydraulic Fracturing

Alpha's review with respect to the specific hydraulic fracturing procedure focused on regulatory processes, i.e., notification, approval and reporting. Among the states Alpha surveyed, Wyoming appears to require the most information.

Pre-Fracturing Notification and Approval

Of the nine states Alpha surveyed, West Virginia, Wyoming, Colorado and Louisiana require notification or approval prior to conducting hydraulic fracturing operations. Pre-approval for hydraulic fracturing is required in Wyoming, and the operator must provide information in advance regarding the depth to perforations or the open hole interval, the water source, the proppants and estimated pump pressure. Consistent with GWPC's recommendation, information required by Wyoming Oil and Gas Commission Rules also includes the trade name of fluids.

Post-Fracturing Reports

Wyoming requires that the operator notify the state regulatory agency of the specific details of a completed fracturing job. Wyoming requires a report of any fracturing and any associated activities such as shooting the casing, acidizing and gun perforating. The report is required to contain a detailed account of the work done; the manner undertaken; the daily volume of oil or gas and water produced, prior to, and after the action; the size and depth of perforation; the quantity of sand, chemicals and other material utilized in the activity and any other pertinent information.

5.18.3.2 Alpha – Other Activities

The Department's development of the overall mitigation approach proposed in this SGEIS also considered Alpha's discussion of other topics included in the regulatory survey. Key points are summarized below.

Pit Rules and Specifications

Alpha's review focused on reserve pits at the well pad. Several states have some general specifications in common. These include:

- Freeboard monitoring and maintenance of minimum freeboard,

- Minimum vertical separation between the seasonal high ground water table and the pit bottom, commonly 20 inches,

- Minimum liner thickness of 20 – 30 mil, and maximum liner permeability of 1×10^{-7} cm/sec,

- Compatibility of liner material with the chemistry of the contained fluid, placement of the liner with sufficient slack to accommodate stretching, installation and seaming in accordance with the manufacturer's specifications,

- Construction to prevent surface water from entering the pit,

- Sidewalls and bottoms free of objects capable of puncturing and ripping the liner, and

- Pit sidewall slopes from 2:1 to 3:1.

Alpha recommends that engineering judgment be applied on a case-by-case basis to determine the extent of vertical separation that should be required between the pit bottom and the seasonal high water table. Consideration should be given to the nature of the unconsolidated material and the water table; concern may be greater, for example, in a lowland area with high rates of inflow from medium- to high-permeability soils than in upland till-covered areas.

Reclamation and Waste Disposal

In addition to its regulatory survey, Alpha also reviewed and discussed best management practices directly observed in the northern tier of Pennsylvania and noted that "[t]he reclamation approach and regulations being applied in PA may be an effective analogue going forward in New York."[126] The best management practices referenced by Alpha include:

- Use of steel tanks to contain flowback water at the well pad,

- On-site or offsite flowback water treatment for re-use, with residual solids disposed or further treated for beneficial use or disposal in accordance with Pennsylvania's regulations,

- Offsite treatment and disposal of produced brine,

- On-site encapsulation and burial of drill cuttings if they do not contain constituents at levels that exceed Pennsylvania's environmental standards,

[126] Alpha, 2009. p. 2-15.

- Containerization of sewage and putrescible waste and transport off-site to a regulated sewage treatment plant or landfill,

- Secondary containment structures around petroleum storage tanks and lined trenches to direct fluids to lined sumps where spills can be recovered without environmental contamination, and

- Partial reclamation of well pad areas not necessary to support gas production.

Alpha noted that perforating or ripping the pit liner prior to on-site burial could prevent the formation of an impermeable barrier or the formation of a localized area of poor soil drainage. Addition of fill may be advisable to mitigate subsidence as drill cuttings dewater and consolidate.[127]

Water Well Testing

Of the jurisdictions surveyed, Colorado and the City of Fort Worth have water well testing requirements specifically directed at unconventional gas development within targeted regions. Colorado's requirements are specific to two particular situations: drilling through the Laramie Fox Hills Aquifer and drilling coal-bed methane wells. Fort Worth's regulations pertain to Barnett shale development, where horizontal drilling and high-volume hydraulic fracturing are performed, and address all fresh water wells within 500 feet of the surface location of the gas well. Ohio requires sampling of wells within 300 feet prior to drilling within urbanized areas. West Virginia also has testing requirements for wells and springs within 1,000 feet of the proposed oil or gas well. Louisiana, while it does not require testing, mandates that the results of voluntary sampling be provided to the landowner and the regulatory agency.

Pennsylvania regulations presume the operator to be the cause of adverse water quality impacts unless demonstrated otherwise by pre-drilling baseline testing, assuming permission was given by the landowner. Alpha suggests that the following guidance provided by Pennsylvania and voluntarily implemented by operators in the northern tier of Pennsylvania and southern tier of New York should be effective:

[127] Alpha, 2009. p. 2-15

- With the landowner's permission, monitor the quality of any water supply within 1,000 feet of a proposed drilling operation (at least one operator expands the radius to 2,000 feet if there are no wells within 1,000 feet);

- Analyze the water samples using an independent, state certified, water testing laboratory; and

- Analyze the water for sodium, chlorides, iron, manganese, barium and arsenic. (Alpha recommends analysis for methane types, total dissolved solids, chlorides and pH.)

Fluid Use and Recycling

Regarding surface water withdrawals, Alpha found that the most stringent rules in the states surveyed are those implemented in Pennsylvania by the Delaware and Susquehanna River Basin Commissions.

None of the states surveyed have any requirements, rules or guidance relating to the use of treated municipal waste water.

Ohio allows the re-use of drilling and flowback water for dust and ice control with an approval resolution, and will consider other options depending on technology. West Virginia recommends that operators consider recycling flowback water.

Practices observed in the northern tier of Pennsylvania include treatment at the well pad to reduce TDS levels below 30,000 ppm. The treated fluids are diluted by mixing with fresh makeup water and used for the next fracturing project.

Materials Handling and Transport

Alpha provided the review of pertinent federal and state transportation and container requirements that is included in Section 5.5, and concluded that motor transport of all hazardous fracturing additives or mixtures to drill sites is adequately covered by existing federal and NYSDOT regulations.[128] Best management practices such as the following were identified by Alpha for implementation on the well pad:

- Monitoring and recording inventories,

[128] Alpha, 2009. p. 2-31

- Manual inspections,
- Berms or dikes,
- Secondary containment,
- Monitored transfers,
- Stormwater runoff controls,
- Mechanical shut-off devices,
- Setbacks,
- Physical barriers, and
- Materials for rapid spill cleanup and recovery.

Minimization of Potential Noise and Lighting Impacts

Colorado, Louisiana, and the City of Fort Worth address noise and lighting issues. Ohio specifies that operations be conducted in a manner that mitigates noise. With respect to noise mitigation, sample requirements include:

- Ambient noise level determination prior to operations;
- Daytime and nighttime noise level limits for specified zones (in Colorado, e.g., residential/agricultural/rural, commercial, light industrial and industrial) or for distances from the wellsite, and periodic monitoring thereof;
- Site inspection and possibly sound level measurements in response to complaints;
- Direction of all exhaust sources away from building units; and
- Quiet design mufflers or equivalent equipment within 400 feet of building units.

The City of Fort Worth has much more detailed noise level requirements and also sets general work hour and day of the week guidelines for minimizing noise impacts, in consideration of the population density and urban nature of the location where the activity occurs.

Alpha found that lighting regulations, where they exist, generally require that site lighting be directed downward and internally to the extent practicable. Glare minimization on public roads and adjacent buildings is a common objective, with a target distance of 300 feet from the well in Louisiana and Fort Worth and 700 feet from the well in Colorado. Lighting impact considerations must be balanced against the safety of well site workers.

Setbacks

Alpha's setback discussion focused on water resources and private dwellings. The setback ranges in Table 5.18 were reported regarding the surveyed jurisdictions:

Table 5-18 - Water Resources and Private Dwelling Setbacks from Alpha, 2009

	Water Resources	Private Dwellings	Measured From
Arkansas	200 feet from surface waterbody or wetland, or 300 feet for streams or rivers designated as Extraordinary Resource Water, Natural and Scenic Waterway, or Ecologically Sensitive Water Body	200 feet, or 100 feet with owner's waiver	Storage tanks
Colorado	300 feet ("internal buffer;" applies only to classified water supply segments – see discussion below)	Not reported	Surface operation, including drilling, completion, production and storage
Louisiana	Not reported	500 feet, or 200 feet with owner's consent	Wellbore
New Mexico	300 feet from continuously flowing water course; 200 feet from other significant water course, lake bed, sinkhole or playa lake; 500 feet from private, domestic, fresh water wells or springs used by less than 5 households; 1000 feet from other fresh water wells or springs; 500 feet from wetland; pits prohibited within defined municipal fresh water well field or 100-year floodplain	300 feet	Any pit, including fluid storage, drilling circulation and waste disposal pits
Ohio	200 feet from private water supply wells	100 feet	Wellhead
Pennsylvania	200 feet from water supply springs and wells; 100 feet from surface water bodies and wetlands	200 feet	Well pad limits and access roads
City of Fort Worth	200 feet from fresh water well	600 feet, or 300 feet with waiver	Wellbore surface location for single-well pads; closest point on well pad perimeter for multi-well sites
Wyoming	350 feet	350 feet	Pits, wellheads, pumping units, tanks and treatment systems

Multi-Well Pad Reclamation Practices

Except for Pennsylvania, Alpha found that the surveyed jurisdictions treat multi-well pad reclamation similarly to single well pads. Pennsylvania implements requirements for best management practices to address erosion and sediment control.

As with single well pads, partial reclamation after drilling and fracturing are done would include closure of pits and revegetation of areas that are no longer needed.

Naturally Occurring Radioactive Materials (NORM)

Alpha reports that Louisiana, New Mexico and Texas currently are the three states with the most comprehensive oil and gas NORM regulatory programs. These programs, implemented within the last decade, include permitting/licensing requirements, occupational and public exposure limits, exclusion levels, handling procedures, monitoring and reporting requirements and specific disposal regulations.

Stormwater Runoff

Most of the reviewed states have stormwater runoff regulations or best management practices for oil and gas well drilling and development. Alpha suggests that Pennsylvania's approach of reducing high runoff rates and associated sediment control by inducing infiltration may be a suitable model for New York. Perimeter berms and filter fabric beneath the well pad allow infiltration of precipitation. Placement of a temporary berm across the access road entrance during a storm prevents rapid discharge down erodible access roads that slope downhill from the site.

5.18.4 Colorado's Final Amended Rules

Significant changes were made to Colorado's oil and gas rules in 2008 that became effective in spring, 2009. While many topics were addressed, the new rules related to chemical inventorying and public water supply protection are most relevant to the topics addressed by this SGEIS.

5.18.4.1 Colorado - New MSDS Maintenance and Chemical Inventory Rule

The following information is from a training presentation posted on COGCC's website.[129]

[129] http://cogcc.state.co.us; "Final Amended Rules" and "Training Presentations" links, 7/8/2009

The new rule's objective is to assist COGCC in investigation of spills, releases, complaints and exposure incidents. The rule requires the operators to maintain a chemical inventory of chemical products brought to a well site for downhole use, *if* more than 500 pounds is used or stored at the site for downhole use or *if* more than 500 pounds of fuel is stored at the well site during a quarterly reporting period. The chemical inventory, which is *not* submitted to the COGCC unless requested, includes:

- MSDS for each chemical product;
- How much of the chemical product was used, how it was used, and when it was used;
- Identity of trade secret chemical products, but not the specific chemical constituents; and
- Maximum amount of fuel stored.

The operator must maintain the chemical inventory and make it available for inspection in a readily retrievable format at the operator's local field office for the life of the wellsite and for five years after plugging and abandonment.

MSDSs for proprietary products may not contain complete chemical compositional information. Therefore, in the case of a spill or complaint to which COGCC must respond, the vendor or service provider must provide COGCC a list of chemical constituents in any trade secret chemical product involved in the spill or complaint. COGCC may, in turn, provide the information to the Colorado Department of Public Health and Environment (CDPHE). The vendor or service provider must also disclose this list to a health professional in response to a medical emergency or when needed to diagnose and treat a patient that may have been exposed to the product. Health professionals' access to the more detailed information which is not on MSDSs is subject to a confidentiality agreement. Such information regarding trade secret products provided to the COGCC or to health professionals does not become part of the chemical inventory and is not considered public information.

5.18.4.2 Colorado - Setbacks from Public Water Supplies

The following information was provided by Alpha and supplemented from a training presentation posted on COGCC's website.[130]

Colorado's new rules require buffer zones along surface waterbodies in surface water supply areas. Buffer zones extend five miles upstream from the water supply intake and are measured from the ordinary high water line of each bank to the near edge of the disturbed area at the well location. The buffer applies to surface operations only and does not apply to areas that do not drain to classified water supply systems. The buffers are designated as internal (0-300 feet), intermediate (301-500 feet) and external (501-2,640 feet).

Activity within the internal buffer zone requires a variance and consultation with the CDPHE. Within the intermediate zone, pitless (i.e., closed loop) drilling systems are required, flowback water must be contained in tanks on the well pad or in an area with down gradient perimeter berming, and berms or other containment devices are required around production-related tanks. Pitless drilling or specified pit liner standards are required in the external buffer zone. Water quality sampling and notification requirements apply within the intermediate and external buffer zones.

5.18.5 Other States' Regulations – Conclusion

Experience in other states is similar to that of New York as a regulator of gas drilling operations. Well construction and materials handling regulations, including those pertaining to pit construction, when properly implemented and complied with, prevent environmental contamination from drilling and hydraulic fracturing activities. The reviews and surveys summarized above are informative with respect to developing enhanced mitigation measures relative to multi-well pad drilling and high-volume hydraulic fracturing. Consideration of the information presented above is reflected in Chapters 7 and 8 of this SGEIS.

[130] http://cogcc.state.co.us; "Final Amended Rules" and "Training Presentations" links, 7/8/2009