Section 4 – Potential environmental and health impacts

A. Constituents and contaminants associated with hydraulic fracturing

The use of chemicals in hydraulic fracturing

The hydraulic fracturing of a natural gas well involves injecting a mixture of proppant and fluids into the wellbore at high pressure, creating fractures in the rock. The proppant, which is often sand, holds the fractures open. These fractures become pathways for natural gas to flow towards the wellbore, increasing the rate at which natural gas can be extracted. Hydraulic fracturing creates permeability within the shale formation, allowing the well to produce a significant amount of natural gas.

Different types of hydraulic fracturing fluids can be used, but the two most common are slickwater fracturing and nitrogen foam fracturing. Slickwater fracturing (named for its ability to reduce friction, thus reducing the pressure needed to pump the fluid into the wellbore), is the most commonly used method; slickwater fracturing fluids are primarily composed of water. Nitrogen foam fracturing uses nitrogen gas and less water than slickwater fracturing. Since slickwater fracturing is the more commonly used method, it is assumed for the purposes of this report that slickwater fracturing would be used in the development of shale gas in North Carolina.

Slickwater fracturing fluids typically consist of 98 to 99.5 percent water and sand. The New York State Department of Environmental Conservation (NYSDEC) studied the compositions by weight of a sample of fracturing fluid used in the Fayetteville Shale and a sample of fluid used in the Marcellus Shale. NYSDEC found that between approximately 84 – 90 percent of the fracturing fluid is water, and between 8 – 15 percent is sand.[105]

In addition to water and sand (or other proppants), operators use a number of chemical additives are to condition the water. Additives may be used to thicken or thin the fluid, prevent corrosion of the well casing, kill bacteria or for other purposes. The mixture of constituents used in hydraulic fracturing fluid for a particular drilling operation varies depending on the drilling company, specific characteristics of the geologic basin (such as depth, temperature, thermal maturity and structural characteristics), and the well operator's objectives.[106]

Given the inherent variability in the composition of hydraulic fracturing fluids, we cannot know the exact composition of hydraulic fracturing fluids that could be used in North Carolina.

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[105] New York State Department of Environmental Conservation (NYSDEC). *Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program,* p. 5-51. Completed September 7, 2011. Retrieved September 7, 2011 from http://www.dec.ny.gov/energy/75370.html.
[106] NYSDEC, p. 5-39.

Any given hydraulic fracturing mixture typically contains between six and 12 chemical additives. Although a limited number of additives would be used at a particular drilling site, hundreds of different chemical additives may be in use across the country. In 2011, the Committee on Energy and Commerce of the United States House of Representatives completed a study on chemicals used in hydraulic fracturing operations. The Committee asked 14 leading oil and gas service companies to disclose the types and volumes of hydraulic fracturing products used in hydraulic fracturing fluids between 2005 and 2009.[107] The Committee found that during that time period, the 14 oil and gas service companies used more than 2,500 hydraulic fracturing products containing 750 chemicals and other components. This totaled 780 million gallons of additives, not including the water that is added to hydraulic fracturing fluids at the well site before injection.

NYSDEC collected information on additives proposed for use in fracturing in New York from 15 chemical suppliers and six service companies.[108] This information included material safety data sheets and "product composition disclosures consisting of chemical constituent names and their associated Chemical Abstract Service (CAS) Numbers, as well as chemical constituent percent by weight information." NYSDEC obtained information for 235 products, which included 322 unique chemicals with CAS numbers and at least another 21 compounds that have no disclosed CAS number because they are mixtures. The list of chemical constituents and CAS numbers that NYSDEC extracted from the product composition disclosures and MSDSs submitted to NYSDEC begins on page 5-55 of NYSDEC's *Revised Draft Supplemental Generic Environmental Impact Statement on the Oil, Gas and Solution Mining Regulatory Program.*

The Groundwater Protection Council and the Interstate Oil and Gas Compact Commission maintain a registry for disclosure of chemicals used in hydraulic fracturing. The registry, FracFocus , notes that "there are a limited number [of chemicals] which are routinely used in hydraulic fracturing." The FracFocus website lists 59 chemicals that are "used the most often."

Classes of chemicals used

As noted above, an operator would only use a small number of additives (typically six to 12) on any single well. The chemical additives fall into certain categories and only one product from each category is used in any given hydraulic fracturing fluid. In addition, it would not be necessary to use a chemical from every category at every well site.[109] The following table shows the categories, purposes and examples of additives reported to NYSDEC as proposed for use in hydraulic fracturing wells in New York State. The categories listed are similar to additives shown on FracFocus (www.fracfocus.org). The exception would be of solvents, a category that does not appear on the FracFocus list. The categories listed in Table 4-1 are also similar to additives

[107] United States. Cong. House. Committee on Energy and Commerce. "Chemicals Used in Hydraulic Fracturing." April 2011. Retrieved January 5, 2012 from http://democrats.energycommerce.house.gov/sites/default/files/documents/Hydraulic%20Fracturing%20Report%204.18.11.pdf.
[108] NYSDEC, pp. 5-40 – 5-41.
[109] NYSDEC, pp. 5-49 – 5-51.

listed in the Department of Energy's *Modern Shale Gas Development in the United States: A Primer*.

Table 4-1. Categories and Purposes of Additives Proposed for Use in New York State[110]

Additive Type	Description of Purpose	Examples of Chemicals
Acids	Removes cement and drilling mud from casing perforations prior to injecting other fracturing fluids, providing an accessible path to the shale formation	Hydrochloric acid (HCl, 3% to 28%) or muriatic acid
Bactericide/Biocide/ Antibacterial Agent	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; 2,2-dibromo-3-nitrilopropionamide
Breaker	Reduces the viscosity of the fluid in order to release proppant into fractures and enhance the recovery of the fracturing fluid	Peroxydisulfates
Buffer/pH Adjusting Agent	Adjusts and controls the pH of the fluid in order to maximize the effectiveness of other additives such as crosslinkers	Sodium or potassium carbonate; acetic acid
Clay stabilizers/Control/KCl	Prevents clays from swelling or shifting, which block pore spaces, reducing permeability	Salts such as potassium chloride (KCl) or tetramethyl ammonium chloride
Corrosion inhibitors (including Oxygen Scavengers)	Reduces rust formation on steel tubing, well casings, tools, and tanks (used only in fracturing fluids that contain acid).	Methanol; ammonium bisulfate for oxygen scavengers
Crosslinker	Increases fluid viscosity using phosphate esters combined with metals. The metals are referred to as crosslinking agents. The increased fracturing fluid viscosity allows the fluid to carry more proppant into the fractures.	Potassium hydroxide; borate salts
Friction reducers	Allows fracture fluids to be injected at optimum rates and pressures by minimizing friction.	Sodium acrylate-acrylamide copolymer; polyacrylamde (PAM); petroleum distillates
Gelling agents	Increases fracturing fluid viscosity, allowing the fluid to carry more proppant	Guar gum; petroleum distillates
Iron control	Prevents the precipitation of metal oxides which could plug off the formation.	Citric acid
Proppants	Hold open the fractures to allow gas to flow more freely to the well bore	Sand, sintered bauxite, zirconium oxide, ceramic beads
Scale inhibitors	Prevents the precipitation of carbonates and sulfates (calcium carbonate, calcium sulfate, barium sulfate) which could plug off the formation.	Ammonium chloride; ethylene glycol
Solvent	Additive which is soluble in oil, water and acid-based treatment fluids which is used to control the wettability of contact surfaces or to prevent or break emulsions.	Various aromatic hydrocarbons
Surfactants	Reduces fracturing fluid surface tension, which aids in fluid recovery	Methanol; isopropanol; ethoxylated alcohol

The Committee on Energy and Commerce of the U.S. House of Representatives found that the most widely used chemical in hydraulic fracturing was methanol, a hazardous air pollutant that is on EPA's list of contaminants that are currently not subject to any proposed or promulgated

[110] This table is based on the table in NYSDEC, p. 5-50 and on a table on page 63 of the Department of Energy's *Modern Shale Gas Development in the United States: A Primer* (written by the Ground Water Protection Council and published in April 2009) and from a table at http://fracfocus.org/chemical-use/what-chemicals-are-used.

national primary drinking water regulations, that are known or anticipated to occur in public water systems, and which may require regulation under the Safe Drinking Water Act (SDWA). Methanol was used in 342 hydraulic fracturing products. Other chemicals that were the most widely used were isopropyl alcohol, ethylene glycol and crystalline silica.

Another commonly used chemical is 2-butoxyethanol (2-BE), which is used by hydraulic fracturing companies as a surfactant. The Committee writes, "According to EPA scientists, 2-BE is easily absorbed and rapidly distributed in humans following inhalation, ingestion, or dermal exposure. Studies have shown that exposure to 2-BE can cause hemolysis (destruction of red blood cells) and damage to the spleen, liver, and bone marrow."[111]

Aquatic toxicity knowledge for certain chemicals used in hydraulic fracturing may be limited. Expected or predicted effects to the aquatic community, on a long-term or short-term basis, may be unknown.

Use of proprietary chemicals

Knowledge of the chemicals used in hydraulic fracturing remains imperfect. Many companies failed to provide the Committee on Energy and Commerce with a complete chemical makeup for their hydraulic fracturing fluids. The Committee found that "Between 2005 and 2009, the companies used 94 million gallons of 279 products that contained at least one chemical or component that the manufacturers deemed proprietary or a trade secret."[112] In some cases, oil and gas companies purchased these products off the shelf from chemical suppliers, and simply did not know what chemicals they were using. In the event of a spill, lack of knowledge about the chemical makeup could pose challenges for emergency responders. Without established groundwater and surface water standards, potential toxic effects to both human health and aquatic life may be unknown.

Health information related to hydraulic fracturing fluids

Fracturing fluids can pose both public health and environmental concerns; exposure to hydraulic fracturing additives should occur, however, only in the case of an accident, spill or other non-routine incident. Exposure could occur either while transporting additives to the well pad, during well pad operations or while transporting wastewater. After chemicals have been injected for hydraulic fracturing, a certain amount of the fluid returns to the surface as "flowback." This wastewater is stored in pits or tanks at the surface; absent sufficient safeguards, this wastewater can spill or overflow following heavy rainfall. If these chemicals are not properly disposed of or if an accident occurs in which fluids spill onto the ground or into surface waters, the fracturing fluid could pose threats to human health, the environment and to the health of livestock or wildlife. In the event of improper cementing of well casings, these chemicals could contaminate drinking water supplies. If a spill or other release occurred, more

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[111] United States. Cong. House. Committee on Energy and Commerce. "Chemicals Used in Hydraulic Fracturing." April 2011. Retrieved January 5, 2012 from http://democrats.energycommerce.house.gov/sites/default/files/documents/Hydraulic%20Fracturing%20Report%204.18.11.pdf, p. 7.

[112] Ibid, p. 2.

specific information about the chemicals involved would be required in order to assess the public health and environmental impacts.

The New York State Department of Environmental Conservation (NYSDEC) requested assistance from the New York State Department of Health (NYSDOH) in identifying potential exposure pathways and constituents of concern associated with hydraulic fracturing. NYSDOH assessed the health concerns by examining chemicals grouped into categories according to their chemical structure (or function in the case of microbiocides). Based on this assessment, NYSDEC concludes,

> "Chemicals in products proposed for use in high-volume hydraulic fracturing include some that, based mainly on occupational studies or high-level exposures in laboratory animals, have been shown to cause effects such as carcinogenicity, mutagenicity, reproductive toxicity, neurotoxicity or organ damage. This information only indicates the types of toxic effects these chemicals can cause under certain circumstances but does not mean that use of these chemicals would cause exposure in every case or that exposure would cause those effects in every case. Whether or not people actually experience a toxic effect from a chemical depends on whether or not they experience any exposure to the chemical along with many other factors including, among others, the amount, timing, duration and route of exposure and individual characteristics that can contribute to differences in susceptibility."[113]

Some of the chemicals used in hydraulic fracturing fluids are relatively harmless, such as salt and citric acid. Others are known or possible human carcinogens. The oil and gas service companies that reported to the Committee on Energy and Commerce used 652 different products containing 29 chemicals that are "(1) known or possible human carcinogens, (2) regulated under the Safe Drinking Water Act for their risks to human health, or (3) listed as hazardous air pollutants under the Clean Air Act."[114]

Many of the chemicals used in hydraulic fracturing fluids are also regulated under the Clean Water Act for their toxic effects to human health, fish and wildlife. More information on these toxic substances can be found below.

Carcinogens

The Committee found that between 2005 and 2009, hydraulic fracturing operators used 95 products containing 13 different known, probable, or possible carcinogens.[115] These included naphthalene, benzene, and acrylamide. In the Committee's study, companies injected 10.2 million gallons of fracturing additives containing at least one carcinogen. Many of these chemicals also have adverse non-cancer human health effects, such as impacts to the kidney, liver and lungs.

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[113] NYSDEC, p. 5-79.
[114] U.S. House of Representatives Committee on Energy and Commerce, p. 8.
[115] Ibid, p. 9.

Safe Drinking Water Act considerations

In most cases, underground injection of chemicals requires a permit under the Underground Injection Control (UIC) provisions of the Safe Drinking Water Act (SDWA). Congress modified the law in 2005, however, to exclude "the underground injection of fluids or propping agents (other than diesel fuels) pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities" from regulation under the Act. Unless diesel fuel is used in the hydraulic fracturing process, EPA does not regulate the permanent underground injection of chemicals used for hydraulic fracturing.[116]

Diesel fuel has been used as an additive in hydraulic fracturing fluids and according to some sources, companies continue to use diesel fuel. The use of diesel is a concern because it contains toxic constituents, including the BTEX compounds benzene, toluene, ethylbenzene and xylenes. Benzene is a human carcinogen, while chronic exposure to toluene, ethylbenzene or xylenes can damage the central nervous system, liver and kidneys.[117]

In 2003, the EPA entered into a memorandum of agreement with the three largest providers of hydraulic fracturing fluids "to eliminate the use of diesel fuel in hydraulic fracturing fluids injected into coalbed methane production wells in underground sources of drinking water."[118]

Congress excluded use of diesel fuel in hydraulic fracturing from the general exemption of hydraulic fracturing from regulation under the UIC provisions of the Safe Drinking Water Act "because of concern about the risks to drinking water from diesel fuel."[119] This means that any operator who uses diesel as a hydraulic fracturing additive should receive approval under the UIC program to do so.

Many assumed that the combination of EPA's memorandum of agreement with hydraulic fracturing fluid providers and continued regulation of hydraulic fracturing with diesel fuel under the UIC program would cause the industry to abandon use of diesel as a hydraulic fracturing additive. In fact, EPA staff told the U.S. House of Representatives Committee on Energy and Commerce that "the agency assumed that the MOA had eliminated most diesel use."[120] In February 2010, the Committee began an investigation into hydraulic fracturing, collecting information from 14 oil and gas service companies. The companies voluntarily provided data,

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[116] Ibid.

[117] United States. Cong. House. Committee on Energy and Commerce. "Waxman, Markey, and DeGette Investigation Finds Continued Use of Diesel in Hydraulic Fracturing Fluids." January 31, 2011. Retrieved January 5, 2012 from http://democrats.energycommerce.house.gov/index.php?q=news/waxman-markey-and-degette-investigation-finds-continued-use-of-diesel-in-hydraulic-fracturing-f.

[118] United States Environmental Protection Agency. "A Memorandum of Agreement between the United States Environmental Protection Agency and BJ Services Company, Halliburton Energy Services, Inc., and Schlumberger Technology Corporation." Retrieved February 26, 2012 from http://s3.amazonaws.com/propublica/assets/natural_gas/diesel_agreement_031212.pdf.

[119] United States Environmental Protection Agency. "Natural Gas Extraction: Hydraulic Fracturing." Retrieved January 23, 2012 from http://www.epa.gov/hydraulicfracture/#diesel.

[120] United States. Cong. House. Committee on Energy and Commerce. "Waxman, Markey, and DeGette Investigation Finds Continued Use of Diesel in Hydraulic Fracturing Fluids." January 31, 2011. Retrieved January 5, 2012 from http://democrats.energycommerce.house.gov/index.php?q=news/waxman-markey-and-degette-investigation-finds-continued-use-of-diesel-in-hydraulic-fracturing-f.

including material safety data sheets, on the volume of diesel fuel and other additives used from 2005 to 2009. The Committee found that 12 of the 14 hydraulic fracturing companies injected more than 30 million gallons of diesel fuel or hydraulic fracturing fluids containing diesel fuel in wells in 19 states. In addition, the Committee found that 60 hydraulic fracturing products in use between 2005 and 2009 contained the BTEX compounds (benzene, toluene, ethyl benzene, xylene). Those products were used in 11.4 million gallons of hydraulic fracturing fluids.[121]

To assess whether these companies obtained the required UIC permit to use diesel fuel as a hydraulic fracturing component under the SDWA, the Committee contacted state agencies and EPA regional offices in the 19 states where diesel fuel was used as a component of hydraulic fracturing fluids. No state or EPA office contacted had ever issued a UIC permit for use of diesel fuel in fracturing or received an application for a UIC permit to authorize its use. Some of the state regulators who were contacted expressed doubt that diesel fuel had been used in hydraulic fracturing.[122] EPA is currently developing permitting guidance for hydraulic fracturing using diesel fuels under SDWA Underground Injection Control Class II regulations.

The UIC exemption described only applies to injection for purposes of fracturing; underground injection of drilling wastes continues to require a Class II injection well permit from EPA or a state that has authority to implement the program. At present, North Carolina has an EPA-approved program for permitting of all classes of injection wells, but N.C. General Statute 143-214.2(b) prohibits the use of wells for waste disposal.

Surface water contamination

The Clean Water Act applies to any discharge of fluids used or produced in the hydraulic fracturing process to surface waters. Drilling wastewater may be temporarily stored in tanks or pits at the well site, where spills are possible. Operators who do not dispose of wastewater by injection into underground injection wells as described above, may transport it to wastewater treatment facilities regulated under the Clean Water Act, or dispose of it through land application methods regulated by states.

There are concerns about the ability of wastewater treatment plants to adequately treat this type of wastewater. In 2011, Gov. Tom Corbett and the Pennsylvania Department of Environmental Protection asked natural gas drillers to stop sending wastewater from drilling operations to the 15 publicly owned water treatment plants that were accepting it at the time because of concern over the elevated levels of bromide being discharged to rivers in the wastewater effluent. Although bromide is non-toxic, when bromide mixed with chlorine for

[121] United States. Cong. House. Committee on Energy and Commerce. “Chemicals Used in Hydraulic Fracturing.” April 2011. Retrieved January 5, 2012 from http://democrats.energycommerce.house.gov/sites/default/files/documents/Hydraulic%20Fracturing%20Report%204.18.11.pdf p. 10.

disinfection at a water treatment facilities becomes "a combination of potentially unsafe compounds called Total Trihalomethanes."[123]

Some of the chemicals used in the hydraulic fracturing process have North Carolina Surface Water and Groundwater Quality Standards; however, many do not. If these chemicals are released to North Carolina waters, defensible and enforceable state water quality standards are needed to address potential adverse effects to public health and the environment.

Hazardous Air Pollutants

The Clean Air Act requires EPA to control the emissions of 187 hazardous air pollutants. Hazardous air pollutants are pollutants that are known or are suspected to cause cancer or other serious health effects, such as reproductive problems, birth defects or developmental, respiratory and other health problems. Hazardous air pollutants can also cause adverse environmental effects. In addition to exposure through breathing, hazardous air pollutants can be deposited onto soils or surface waters and taken up by plants or ingested by animals. Humans can then be exposed to these toxic pollutants by eating exposed plants or animals. Animals may also experience health problems if exposed to sufficient quantities of air toxics over time.[124]

EPA regulates emissions of hazardous air pollutants through Maximum Achievable Control Technology (MACT) standards. The state of North Carolina issues federal Clean Air Act permits that include MACT standards for any federally regulated source of hazardous air emissions in the state. North Carolina also has a state health-based program to regulate emissions of toxic air pollutants. The state program, which has been in effect since May 1, 1990, regulates 105 toxic air pollutants (TAPs). Most of the TAPs are also considered HAPs by the EPA. The state program reaches some sources of toxic air emissions that are not regulated under the federal program.

According to the survey of chemicals used in hydraulic fracturing operations by the U.S. House Energy and Commerce Committee, oil and gas companies used 595 products containing 24 chemicals capable of producing hazardous air emissions between 2005 and 2009.[125] Examples of these chemicals included hydrogen fluoride, lead and methanol. Hydrogen fluoride can cause severe and sometimes delayed health effects due to deep tissue penetration. Lead is particularly harmful to children's neurological development but can also cause health problems in adults. The EPA reports that exposure to small amounts of methanol can cause headaches, incoordination, sleep disorders, gastrointestinal problems and optic nerve damage.[126]

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[123] Gresh, Katy. "DEP Calls on Natural Gas Drillers to Stop Giving Treatment Facilities Wastewater." Pennsylvania Department of Environmental Protection. April 19, 2011. Retrieved February 26, 2012 from http://www.portal.state.pa.us/portal/server.pt/community/newsroom/14287?id=17071&typeid=1.
[124] EPA. http://www.epa.gov/oar/toxicair/newtoxics.html. Retrieved January 18, 2012.
[125] U.S. House of Representatives Committee on Energy and Commerce, 2011.
[126] United States Environmental Protection Agency. "Chemicals in the Environment: Methanol (CAS No. 67-56-1)." August 1994. Retrieved February 26, 2012 from http://www.epa.gov/chemfact/f_methan.txt.

Endocrine disruptors

Endocrine disruptors are chemicals that "produce adverse developmental, reproductive, neurological, and immune effects in both humans and wildlife [and they] may pose the greatest risk during prenatal and early postnatal development when organ and neural systems are forming."[127] The Endocrine Disruption Exchange (TEDX) has conducted analysis of the potential health effects of the products and chemicals used in natural gas operations. TEDX is a nonprofit organization "dedicated to compiling and disseminating the scientific evidence on the health and environmental problems caused by low-dose exposure to chemicals that interfere with development and function, called endocrine disruptors."[128] Endocrine disruptors can have effects at low doses, even lower than doses used for traditional toxicological studies.[129] TEDX has collected information about hydraulic fracturing products and chemicals from a variety of sources, including environmental impact statements, rule-making documents, accident and spill reports, federal and state agencies, the natural gas industry and other sources. TEDX collected material safety data sheets (MSDSs) for additives commonly used in hydraulic fracturing, which contain some information on the composition of products. Most MSDSs do not disclose all of the chemicals in a product, and may list ingredient types, such as surfactants or biocides, rather than the specific ingredient name. TEDX used MSDSs and other sources to identify Chemical Abstract Service numbers, a more specific way to identify chemicals because CAS numbers provide a unique identifier.

TEDX identified 980 products, containing a total of 649 chemicals. Based on analysis performed by TEDX, 47 percent of the 980 products examined contained chemicals considered to be endocrine disruptors. These products "have the potential to affect the endocrine system, including human and wildlife development and reproduction." The endocrine system is "susceptible to very low levels of exposure."[130]

Chemicals used aboveground

In addition to the chemicals that are pumped into well bores to enhance hydraulic fracturing, drilling for natural gas involves the use of a number of chemicals aboveground. These chemicals could potentially pose a threat to public health or the environment if they are spilled either at the drilling site or in transit. Drilling rigs require power to drill and case wellbores. Typically, in the Marcellus Shale, this power would be provided by transportable diesel engines.[131] During hydraulic fracturing, "To inject the required water volume and achieve the necessary pressure, up to 20 diesel-pumper trucks operating simultaneously are necessary" for a period of two to

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[127] National Institute of Environmental Health Sciences. "Endocrine Disruptors." Retrieved April 14, 2012 from http://www.niehs.nih.gov/health/topics/agents/endocrine/index.cfm.
[128] "The Endocrine Disruption Exchange." Retrieved April 14, 2012 from http://www.endocrinedisruption.org/home.php.
[129] Vandenberg, Laura N. et al. "Hormones and Endocrine-Disrupting Chemicals: Low-Dose Effects and Nonmonotonic Dose Responses." *Endocrine Reviews*, June 2012. Retrieved April 14, 2012 from http://edrv.endojournals.org/content/early/2012/03/14/er.2011-1050.full.pdf+html.
[130] The Endocrine Disruption Exchange. "Health Effects Spreadsheet and Summary." Retrieved April 14, 2012 from http://www.endocrinedisruption.org/files/Multistatesummary1-27-11Final.pdf.
[131] NYSDEC, p. 6-196.

five days per well.[132] Diesel is stored on the well pad for this purpose and "The diesel tank fueling storage may be larger than 10,000 gallons in capacity and may be in one location on a multi-well pad for the length of time required to drill all of the wells on the pad."[133]

In addition to use in hydraulic fracturing operations, hazardous air pollutants also originate from mobile sources, such as the trucks that are used by gas drilling companies. The potential impacts from air emissions are discussed in Section 4.F of this report.

Regulation of hydraulic fracturing chemical disclosure

Some states require the disclosure of the chemical additives used in hydraulic fracturing fluids. The level of disclosure required varies by state. So far, Colorado is the only state to require the names and concentrations of all individual chemicals used.[134] Some states merely require the compilation of material safety data sheets (MSDSs) for additives. The Occupational Safety and Health Administration (OSHA) requires chemical manufacturers to create an MSDS for every product they sell to communicate potential health and safety hazards to employees and employers. The MSDS must list all hazardous ingredients that comprise at least 1 percent of the product; for carcinogens, the reporting threshold is 0.1 percent.[135] Chemical manufacturers do not have to disclose trade secret information on MSDSs, which allows many additives used in hydraulic fracturing to be withheld. Some states require that operators also disclose CAS registry numbers, the unique numerical identifiers for chemicals.

Many states allow reporting of chemical information to be made to FracFocus (www.fracfocus.org), a website managed by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission that serves as a type of clearinghouse for this information. The site was created "to provide the public access to reported chemicals for hydraulic fracturing," but also includes "objective information on hydraulic fracturing, the chemicals used, the purposes they serve and the means by which groundwater is protected." Although FracFocus provides a convenient location for chemical disclosure information from several states, it does have some limitations. Most notably, information is provided via .pdf documents for each well and is not in a database or spreadsheet format that could be used to analyze data across counties, states or other geographies. GWPC plans to release a new version of FracFocus in late 2012 that will include the capability to provide data to states, though not the general public, in spreadsheet format.[136]

Arkansas requires companies to disclose all fracturing fluids, additives, chemical constituents and CAS numbers to the Arkansas Oil and Gas Commission, with the exception of chemicals that

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[132] NYSDEC, p. 6-296.
[133] NYSDEC, p. 7-33.
[134] Groeger, Lena. "Federal Rules to Disclose Fracking Chemicals Could Come with Exceptions." ProPublica. February 16, 2012. Retrieved February 27, 2012 from http://www.propublica.org/article/federal-rules-to-disclose-fracking-chemicals-could-come-with-exceptions.
[135] U.S. House of Representatives Committee on Energy and Commerce, 2011.
[136] Mike Nickolaus, GWPC. Personal communication, March 12, 2012.

are considered trade secrets. [137] Information on concentrations used is not required, but operators report the percent by volume of each product used. The information is disclosed to the state and must be provided to health care professionals who require it. The chemical family is disclosed to the public using the state website. The information is due before hydraulic fracturing begins and updates must be submitted after hydraulic fracturing.[138] The rule became effective on Jan. 15, 2011.[139]

Colorado requires drillers to disclose all the chemicals used in hydraulic fracturing, as well as the concentrations of each chemical and the CAS numbers. Certain chemical names can be withheld as trade secrets. Operators are also required to disclose these chemicals to the public using the FracFocus website and directly to the Colorado Oil & Gas Conservation Commission. Chemicals, including those considered trade secrets, must also be disclosed to health professionals in an emergency when disclosure is necessary. The requirements will be effective April 1, 2012.[140] The trade secret provisions of Colorado's rule are slightly different than in other states. Whereas in other states, companies can determine which chemicals are trade secrets or state regulators or the governor sign off on trade secret requests, "In Colorado, companies will be required to sign a legally-binding form to declare a chemical proprietary. Drillers who lie could be charged with perjury."[141] The information must be posted to FracFocus within 60 days following the conclusion of the hydraulic fracturing treatment.[142]

Louisiana requires operators to disclose additives in products subject to Occupational Safety and Health Administration (OSHA) Hazard Communication requirements (29 CFR 1910.1200), which requires MSDSs for chemicals considered hazardous to worker safety. For these additives, Louisiana requires the disclosure of the chemical names and concentrations of the chemicals. Operators can either report disclosure information to the Office of Conservation or post it to the FracFocus website within 20 days of well completion.[143] According to the Department of Natural Resources, "The Louisiana regulation has no effect on rules or laws mandating disclosure of trade secret information to health care providers." The rules are effective as of Oct. 20, 2011.[144]

Michigan requires that material safety data sheets be filed for hazardous chemicals and matched with the products into which they go. Operators disclose a range of concentrations, not the exact concentration. Proprietary information is not disclosed to regulators or the public.

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[137] Louisiana Department of Natural Resources. "Comparison of State Hydraulic Fracturing Chemical Disclosure Regulations." December 30, 2011. Retrieved February 27, 2012 from http://dnr.louisiana.gov/index.cfm?md=pagebuilder&tmp=home&pid=888.
[138] ProPublica. "Fracking Chemical Disclosure Rules." February 16, 2012. Retrieved February 27, 2012 from http://www.propublica.org/special/fracking-chemical-disclosure-rules.
[139] Louisiana Department of Natural Resources, 2011.
[140] Ibid.
[141] Detrow, Scott. "Colorado Approves Fracking Disclosure Regulations." StateImpact. December 14, 2011. Retrieved February 27, 2012 from http://stateimpact.npr.org/pennsylvania/2011/12/14/colorado-approves-fracking-disclosure-regulations/.
[142] ProPublica. "Fracking Chemical Disclosure Rules." February 16, 2012.
[143] Ibid.
[144] Louisiana Department of Natural Resources, 2011.

MSDSs are posted on the state website and must be provided within 60 days of drilling completion.[145]

Montana requires operators to disclose the names and CAS numbers of chemicals that are not deemed trade secrets to the Montana Oil and Gas Board or to the FracFocus website. Operators provide the chemical family and the maximum concentration of chemicals, not the actual concentration. Proprietary chemicals, as determined by the well operator, can be withheld but must be disclosed to health care professionals in an emergency. MSDSs are required before hydraulic fracturing begins and after it is complete. Disclosure must be made before hydraulic fracturing begins and after it is completed.[146] The requirements are effective for all hydraulic fracturing performed after Aug. 27, 2011.[147]

Ohio requires material safety data sheets, which list the products' chemical components and CAS numbers. Concentrations of chemicals are not disclosed. Proprietary information is not disclosed to regulators or the public. No specific requirements are in place for medical disclosure, but "a regulator from the Ohio Dept. of Natural Resources said he's confident the information would be provided to health care professionals in an emergency."[148] The information is required 60 days after drilling is complete and is posted on the state website.[149]

New Mexico recently adopted regulations that require operators to disclose all additives used in hydraulic fracturing fluids and the names and concentrations of chemicals that are subject to OSHA Hazard Communication requirements. Operators do not have to disclose trade secret information. Disclosure can be made by reporting to the Oil Conservation Division. The rule is effective as of Feb. 15, 2012.[150]

North Dakota has passed new rules related to hydraulic fracturing that became effective on April 1, 2012. The revised regulation requires the owner, operator or service company to post to FracFocus "all elements made viewable by the FracFocus website,"[151] which includes the total volume of water used at the well, the trade names of chemicals used, the supplier of each chemical, the purpose of each chemical, the ingredients, the chemical abstract service number, the maximum ingredient concentration in the additive, and the maximum ingredient concentration in the hydraulic fracturing fluid.[152]

Pennsylvania has a regulation requiring operators to disclose to the Pennsylvania Office of Oil and Gas Management the names of products and chemicals, without matching them with the products into which they go. Operators must also disclose the names and concentrations of

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145 ProPublica. "Fracking Chemical Disclosure Rules." February 16, 2012.
146 Ibid.
147 Louisiana Department of Natural Resources, 2011.
148 ProPublica. "Fracking Chemical Disclosure Rules." February 16, 2012.
149 Ibid.
150 Title 19, *New Mexico Administrative Code*, Chapter 15, Part 16.
151 North Dakota Industrial Commission. "Order of the Commission." Case no. 15869, Order no. 18123. January 23, 2012. Retrieved February 27, 2012 from https://www.dmr.nd.gov/oilgas/or18123.pdf.
152 This list of elements viewable on the FracFocus website was taken from the "Hydraulic Fracturing Fluid Product Component Information Disclosure" for the Dave 2H well in Bradford County, Pennsylvania, retrieved February 27, 2012 from http://www.hydraulicfracturingdisclosure.org/fracfocusfind/.

chemicals subject to OSHA Hazard Communication requirements.[153] All chemical constituents must be provided by the operator if the department makes a request in writing.[154] The information is required within 30 days of well completion. It is not posted online but is available by request from the Department of Environmental Protection.[155] Trade secret information is protected. The requirements are effective as of Feb. 5, 2012.[156]

Texas recently revised its chemical disclosure rules. The revised rules require that service companies disclose to operators the names of products, chemicals that are not deemed trade secrets, and their CAS numbers. Only hazardous chemicals are matched with the products of which they are a component. The concentrations of chemical constituents are only required for chemicals subject to OSHA Hazard Communication requirements.[157] A listing of chemical ingredients used to hydraulically fracture a well that has been permitted by the Texas Railroad Commission on or after Feb. 1, 2012, must be uploaded to the FracFocus website. A supplier, service company or operator is not required to disclose trade secret information unless the Attorney General or court determines the information is not entitled to trade secret protection.[158]

Wyoming has a regulation requiring operators or service companies to disclose the names of products, chemicals and their CAS numbers. Operators must disclose product concentrations but not the concentrations of individual chemical components to the supervisor of the Wyoming Oil and Gas Conservation Commission. The information is not made public.[159] Trade secret information is kept confidential according to the Wyoming Public Records Act. The requirements have been in effect since Aug. 17, 2010.[160]

The United States Bureau of Land Management (BLM) has developed draft regulations applicable to wells that are hydraulically fractured on federal land. The proposed rules would require the disclosure of the names of products, chemicals and CAS numbers. Concentrations of chemicals would be disclosed for some products. At this time the rules are still a draft, and it is unclear whether the information collected by BLM would be posted publicly.[161] BLM's proposed rules would also "compel companies to report the total volume of fracking fluid used, as well as how they intend to recover and dispose of it."[162]

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[153] ProPublica. "Fracking Chemical Disclosure Rules." February 16, 2012.
[154] Louisiana Department of Natural Resources, 2011.
[155] ProPublica. "Fracking Chemical Disclosure Rules." February 16, 2012.
[156] Ibid.
[157] ProPublica. "Fracking Chemical Disclosure Rules." February 16, 2012.
[158] Nye, Ramona. "Railroad Commissioners Adopt One of Nation's Most Comprehensive Hydraulic Fracturing Chemical Disclosure Requirements." Railroad Commission of Texas. December 13, 2011. Retrieved February 27, 2012 from http://www.rrc.state.tx.us/pressreleases/2011/121311.php.
[159] ProPublica. "Fracking Chemical Disclosure Rules." February 16, 2012.
[160] Louisiana Department of Natural Resources, 2011.
[161] ProPublica. "Fracking Chemical Disclosure Rules." February 16, 2012. Retrieved February 27, 2012 from http://www.propublica.org/special/fracking-chemical-disclosure-rules.
[162] Groeger, 2012.

Existing regulation of trade secrets in North Carolina

North Carolina does not currently have a statute or rule that would require disclosure of hydraulic fracturing fluids. Existing provisions in the state's Public Records Act may protect proprietary information submitted to state regulators as part of a permit application or in response to a request. Under G.S. 132-1.2, a public agency may not disclose information that meets the following criteria:

- The information would be a "trade secret" as defined in G.S. 66-152.3;
- The information is owned by a private person (which may include a corporation);
- The information has been provided for purposes of complying with local, state or federal statutes, rules or ordinances; and
- The information was marked as" confidential" or "trade secret" information when it was submitted to the public agency.

Under G.S. 66-152.3, "trade secret" means "business or technical information, including but not limited to a formula, pattern, program, device, compilation of information, method, technique, or process that:

a. Derives independent actual or potential commercial value from not being generally known or readily ascertainable through independent development or reverse engineering by persons who can obtain economic value from its disclosure or use; and
b. Is the subject of efforts that are reasonable under the circumstances to maintain its secrecy.

Other provisions of state law may provide additional insights into what types of information may or may not be protected as a trade secret. For example, G.S. 143-215.3C(b) provides that information related to emissions of air pollutants cannot be protected as a trade secret.

Conclusions related to hydraulic fracturing additives

We recommend that the General Assembly require full disclosure of hydraulic fracturing chemicals and constituents to the state regulatory agency and to local government emergency response officials. We also recommend that the General Assembly should encourage the industry to disclose all hydraulic fracturing chemicals and constituents to the public through the FracFocus website or a state agency website. The General Assembly may need to clarify how current protections for trade secrets under state law apply to the identification of chemicals used in hydraulic fracturing.

The use of diesel fuel in fracturing fluid should be completely prohibited because it contains toxic constituents, including the BTEX compounds benzene, toluene, ethylbenzene and xylenes. Benzene is a human carcinogen, while chronic exposure to toluene, ethylbenzene or xylenes can damage the central nervous system, liver and kidneys.

B. Hydrogeologic framework of the Triassic Basins

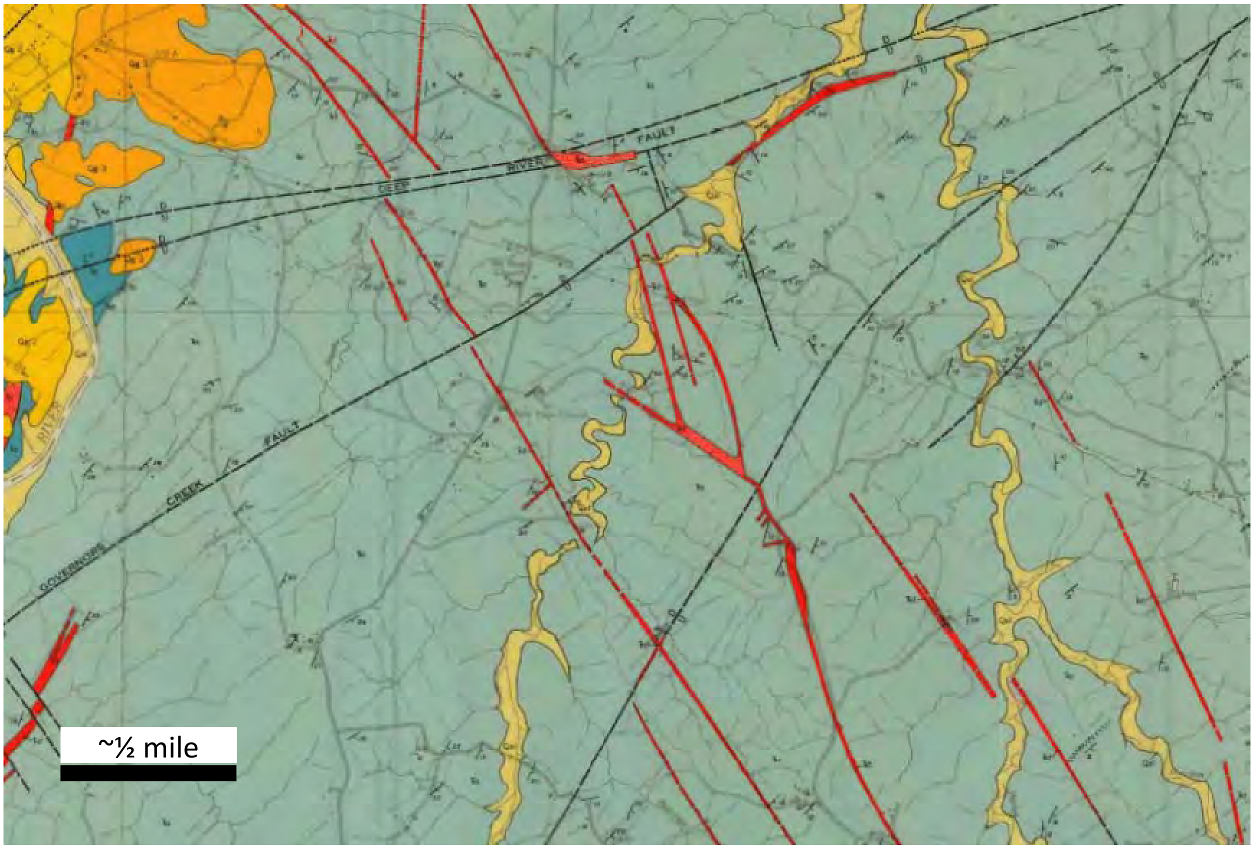
The areas of current interest for potential shale gas development are located within the Deep River Triassic Basin and Dan River Triassic Basin. The Triassic Basins are geologically distinct from the surrounding geologic belts in that they are filled with sedimentary rocks, meaning they have different hydrogeologic properties than the igneous and metamorphic bedrock that is found adjacent to them. The sedimentary rocks that occur in the basin include sandstone, shale, siltstone and conglomerate.

The sedimentary rocks in the Sanford sub-basin tend to have very low permeability due to the presence of fine-grained material commonly occurring within the spaces between the larger grains. There are no defined “aquifers” in the customary sense in the Sanford sub-basin, such as those that occur in the Coastal Plain region of the state. Instead, most water supply wells in the Triassic Basins actually derive their water from fractures in the rock.

Numerous thin bodies of igneous rock intrude into the sedimentary rocks of the basin. A map illustrating these intrusions in a portion of the Sanford sub-basin is shown in Figure X. These intrusions, of a rock known as diabase, are typically long, thin planar bodies ranging in thickness from less than a foot to tens of feet thick. Most often in the Triassic Basins, they occur as near-vertical dikes cutting across older sedimentary rocks. They may also occur as flat-lying sills, but this is much less common. The diabase intrusions are highly fractured, along with the sedimentary rocks immediately adjacent to them and are therefore capable of yielding sufficient quantities of water to support water supply wells. Groundwater can often flow freely for great distances along the edges of these diabase intrusions, but when the diabase intrusions are relatively thick they tend to restrict groundwater flow.

Multiple near-vertical faults also cut through the sedimentary rocks of the Triassic Basins. A map illustrating these faults in a portion of the Sanford Sub-basin is shown in Figure 4-1. These faults can occur in a variety of orientations, but the dominant fault orientations in the Triassic basins of North Carolina are northwest-southeast and, to a lesser extent, northeast-southwest. The degree to which these faults may transmit water is not well understood and warrants additional investigation.

Figure 4-1. Diabase dikes and sills (red) and faults (labeled black lines) cross-cutting sedimentary rocks of the Deep River Triassic Basin northwest of Sanford.



Most knowledge of groundwater conditions in the Triassic Basins comes from wells that have been drilled for water supply. Few studies of the hydrogeology of the Triassic Basins have been conducted. No groundwater monitoring stations have been constructed in the Triassic Basins of North Carolina. Because of this, our understanding of the hydrogeology of the Triassic Basins is limited to information that can be recovered from water supply wells, which typically only extend a few hundred feet deep.

Little relevant data is available on the overall background quality of groundwater in the Triassic Basins. A 1961 study by the U.S. Geological Survey and the N.C. Department of Water Resources (now the divisions of Water Quality and Water Resources within the Department of Environment and Natural Resources) reported sample results for three wells in the Deep River Basin in Lee County and noted that the groundwater in the Deep River Basin tended to be moderately hard to hard.[163]

In 2010, 960 groundwater samples collected from private wells in the 12 counties encompassing the Deep River and Dan River Triassic Basins were tested for chloride levels. [164]

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[163]Schipf, Robert G. . *Geology and Ground-Water Resources of the Fayetteville Area.* North Carolina Department of Water Resources, 1961.

[164] State Public Health Laboratory, N.C. Department of Health and Human Services. Results of private drinking water well samples collected in 2010.Dataset provided to DWQ in March 2011.

The Division of Water Quality does not have sufficiently reliable location data at this time to determine how many of these wells were within the Triassic Basins. Of the 960 samples analyzed for chloride, 10 samples (roughly 1 percent) had chloride concentrations of 250 milligrams per liter (mg/L) or greater, the threshold between fresh water and brackish or saline water. From this very coarse examination, it does not appear that shallow saline groundwater is common in the Triassic Basins. A more rigorous examination of existing groundwater quality in the Sanford Sub-basin is underway as part of an inventory being conducted by the United States Geological Survey (USGS) under contract to DENR.

The sample results described above, along with geological information suggesting that the Triassic Basin rocks were deposited in ancient lakes rather than in marine environments, indicate that groundwater at depths below existing water supply wells is not likely to be saline, although it may be hard. If these results accurately reflect characteristics of deep groundwater in the Triassic Basins, the producing zones and hydraulically fractured intervals of any gas wells will be located in potential future water supplies.[165]

Available groundwater data from North Carolina's Triassic Basins stands in contrast to conditions in Pennsylvania, where the shale gas resource lies at depths of roughly 10,000 feet or more. The deepest water supply wells in that area are generally no more than 600 feet deep, and it is not uncommon to encounter highly saline groundwater at depths of 600 to 750 feet.[166] As a result, Pennsylvania's gas-producing layer lies thousands of feet below groundwater likely to be used for drinking water supply. By contrast, water supply wells of up to 1,000 feet deep have been found in North Carolina's Triassic Basins, and the depth to which freshwater extends is unknown. Some of the shale that might be tapped for natural gas in the Triassic Basins of North Carolina lies at depths of 3,000 feet or less.

Well locations and groundwater use

Statewide, groundwater provides drinking water supply for 42 percent of North Carolinians either by private drinking water wells or public water systems.[167] Groundwater is also the most commonly used source of water for livestock and for irrigation of crops. In most of North Carolina, groundwater provides an easily accessible source of water, and generally is of suitable quality for drinking without treatment. Where public water supplies are unavailable, groundwater and private water supply wells serve a vital role in the economic development of rural areas.

Most water supply wells in the Deep and Dan River Triassic Basins are completed by first drilling and cementing surface casing to isolate the loose material at shallow depths and then drilling an open hole past the casing until reaching a sufficient quantity of water from the bedrock fractures. Some water supply wells in this area are completed as screened wells, meaning the well has been cased along its entire length, but has slots in areas where water is encountered

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[165] As a matter of law, North Carolina groundwater regulations in 15A NCAC 2L .0200 classify all groundwater in the state as a potential source of potable water.
[166] Brian Grove, Chesapeake Energy. Personal communication, January 1, 2012.
[167] USGS. *Estimated Use of Water in the United States: County-Level Data for 2005.* 2010. Accessed August 1, 2011. http://water.usgs.gov/watuse/data/2005/index.html

to allow the water to enter into the well casing. Screened wells are sometimes used if the bedrock is loose and friable in order to keep the well from collapsing.

According to the available well construction records in a DENR database, the average depth for a water supply well in the Deep River basin is 261 feet, with a range of 60 to 720 feet. [168] The average depth of casing in water supply wells in the Deep River Basin is 48 feet, with a range of five to 21 feet. The inventory of existing data on public water supply wells, in Section 3, includes one well 1,000 feet deep in the Deep River basin in Chatham County. In the Dan River Basin the average depth for water supply wells in the same database is 574 feet; depths range from 400 to 1,005 feet. The average depth of casing in water supply wells in the Dan River Basin is 69 feet; depths range from 41 to 126 feet. The inventory of existing data on public water supply wells, in Section 3 includes one well 1,230 feet deep in the Dan River basin in Stokes County. Well casing depths of less than 20 feet may occur in wells completed before 1972, the date when North Carolina well construction standards were adopted and implemented. In 1972, well construction standards began requiring well casing depths of at least 20 feet.

The USGS, under contract to DENR, is compiling an inventory of water supply wells in the 59,000 acre potential target area identified by the NCGS in northwestern Lee County and southeastern Chatham County. This inventory will provide more detailed information about groundwater quality and water supply well construction characteristics in the potential target area. The inventory may also be useful for identifying wells that should be tested, inspected or even closed prior to any additional drilling of natural gas wells. The USGS is using paper and electronic records from the N.C. Division of Water Quality and Lee and Chatham County health departments to document the locations and construction characteristics of wells in the potential target area. As of February 2012, the USGS had compiled 387 well construction records in the study area. Among these wells, well depths average 278 feet and yields average 13 gallons per minute.[169]

USGS is also compiling available groundwater quality analytical results from the local health departments and the N.C. Department of Health and Human Services. The USGS plans to collect groundwater quality samples from a subset of wells identified by this well inventory. The USGS expects to sample nine private wells and one community well near the two gas test wells drilled in 1997 and analyze these samples for dissolved gases, carbon isotopes in methane and ethane, major ions, metals, nutrients, volatile organic compounds, radium isotopes, gross alpha and beta and strontium isotopes. The USGS expects to sample an additional 40 water supply wells in the inventory area for dissolved gases and major ions.[170] The USGS hopes to complete the well inventory by mid-April 2012 and publish results of the inventory by May 1, 2012.

In the absence of a complete inventory of water supply well locations, it may be assumed that any parcel of land in North Carolina that is not served by a community water system is served by an onsite water supply well. In some cases, a property that is served by a community water system may still have an onsite water supply well for irrigation, livestock or other uses.

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[168] NC DENR. "GW-1" Well Construction Records Database, accessed January 31, 2012.
[169] Melinda Chapman, USGS. Personal communication, February 24, 2012.
[170] Melinda Chapman, USGS. Personal communication, February 24, 2012.

Water use estimates compiled by the USGS at the county level provide an overall impression of the level to which the population in and surrounding the Triassic Basins depend on groundwater.[171] The USGS water-use estimates are not compiled at a scale finer than the county level, therefore it is not possible to characterize groundwater use within the Triassic Basins themselves. A summary of groundwater use for domestic purposes in 12 counties that contain a portion of the Triassic Basins is presented in Table 4-2. Yadkin, Davie and Union counties are not included in this table because no organic-rich shale has been reported from the basins within these counties.

Groundwater from public and private sources serves the domestic water needs of nearly half a million residents of the counties containing significant parts of the Triassic Basins, or roughly 30 percent of the population in counties encompassing the Triassic Basins. In Moore County, groundwater serves the domestic water needs of three-quarters of the population of the county.

[171] USGS, 2010.

Table 4-2. Summary of Domestic Water Use in Counties containing the Deep River and Dan River Triassic Basins in 2005[172]

County	Total Population	Population Relying on Groundwater from Public Water Systems	Population Relying on Self-Supplied Groundwater	Total Population Relying on Groundwater	Percentage of Population Relying on Self-Supplied Groundwater	Total Percentage of Population Relying on Groundwater
Anson	25,499	-	2,704	2,704	11%	11%
Chatham	58,002	1,760	32,080	33,840	55%	58%
Durham	242,582	3,670	50,459	54,129	21%	22%
Granville	53,674	1,280	29,202	30,482	54%	57%
Lee	55,704	2,340	8,170	10,510	15%	19%
Montgomery	27,322	80	8,213	8,293	30%	30%
Moore	81,685	26,930	34,920	61,850	43%	76%
Orange	118,386	4,840	20,312	25,152	17%	21%
Richmond	46,781	-	7,609	7,609	16%	16%
Rockingham	92,614	2,990	40,840	43,830	44%	47%
Stokes	45,858	2,040	23,569	25,609	51%	56%
Wake	748,815	61,780	110,283	172,063	15%	23%
All 12 Counties	1,596,922	107,710	368,361	476,071	23%	30%

[172] USGS, 2010.

C. Potential groundwater impacts

Stray gas migration

Two forms of methane can be found in the subsurface, both as free phase gas and as dissolved gas in groundwater: biogenic and thermogenic. Biogenic methane is formed at relatively shallow depths and is created by the decomposition of organic matter by biological activity or by the chemical reduction of carbon dioxide. Thermogenic methane is typically formed at much greater depths than biogenic methane by the thermal decomposition of buried organic material. Thermogenic methane is the type sought for natural gas development. Both types of methane can occur naturally in the subsurface environment, and the only way to distinguish between them is through isotopic analysis of the carbon atoms in the methane.

While thermogenic gas and biogenic gas are distinguished based on isotopic analysis, many sources of either type of gas may exist in the subsurface, including:[173]

- Naturally occurring gas seeps
- Abandoned, recently drilled and operating gas wells
- Abandoned coal mines
- Natural gas pipelines
- Abandoned and operating landfills
- Naturally occurring shallow formations and aquifers
- Buried organic matter
- Drift gas

Not all of these sources may be subject to regulation, particularly in the case of naturally-occurring sources. The process of well drilling can create disturbances of subsurface sources of stray gas that alter migration pathways. No such incidents are known to have occurred in North Carolina due to normal water well construction.

Finding the source of natural gas migration requires investigation and analysis of several types of data including gas geochemistry and information on the mechanism of migration. Given the potential occurrence of multiple man-made and naturally occurring gas sources, the best way to determine whether oil and gas development has caused stray gas migration is by characterizing background groundwater quality prior to drilling activity. Stray gas migration incidents should be thoroughly investigated and supported by multiple lines of evidence, principally, geochemistry and analyses documenting a mechanism of migration.

Osborn and others showed that water supply wells close to active exploration and production wells in the Marcellus shale have higher levels of dissolved methane than wells farther away.[174]

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[173] Baldassare, F.J. 2011. "The origin of some natural gases in Permian through Devonian age systems in the Appalachian Basin & the relationship to incidents of stray gas migration," U.S. EPA, *Proceedings for USEPA Technical Workshop for Hydraulic Fracturing Study, Chemical & Analytical Methods.* Accessed February 10, 2012. http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/upload/proceedingsofhfchemanalmethodsfinalmay2011.pdf,

Their study did not find constituents of hydraulic fracturing fluids in any of the water supply wells that were sampled. The study did find methane in water supply wells. The methane had an isotopic signature indicating that it originated from a thermogenic source, suggesting a Marcellus shale source, rather than from shallow biogenic sources (such as manure piles or decaying organic matter). However, another recent study suggests that the source of this thermogenic gas is actually from shallower geologic formations in which the water supply wells are completed, rather than from the much deeper Marcellus shale.[175] The source, route and mechanism for the dissolved methane occurrences observed in the study by Osborne and others remains unresolved, so it is not clear whether these occurrences are the result of gas exploration and production or coincidental with it, nor is it clear how such occurrences might be prevented if they are caused by exploration and production.

Well construction

Well construction can impact groundwater quality through a number of pathways:

- The process of drilling oil or gas wells can disrupt the quality and quantity of water in water supply wells due to the circulation of drilling fluids under pressure, especially when large voids or fracture zones are encountered in the initial stages of drilling the oil or gas well.
- Improperly constructed oil or gas wells can provide a conduit for the upward migration of deeper formation water and well stimulation fluids.
- Improperly constructed water supply wells can allow contaminants in shallower groundwater to move between water bearing zones

Gas well construction

Modern hydraulically fractured gas wells are constructed with multiple layers of casing and cement, as shown in Figure 4-2. The purpose of the layers of casing and cement is to protect both groundwater and the gas-producing zone. Typically, after the gas well has been drilled to a depth of 50 to 80 feet, a large-diameter steel pipe known as conductor casing is placed in the hole in order to keep unconsolidated materials from collapsing into the hole. This casing is cemented in place by pushing cement through the bottom of the casing and up the sides of the casing to the surface. After curing of the cement, a smaller diameter drill bit is used to continue drilling to a point below the deepest fresh groundwater. A second string of steel pipe, known as surface casing, is assembled and inserted into the borehole to this depth and cemented in place. Again, a smaller diameter drill bit is used to continue drilling to the depth of any additional zones that need to be isolated from the producing zone. An intermediate casing is then placed to this depth and cemented in place. Following curing of the cement around the

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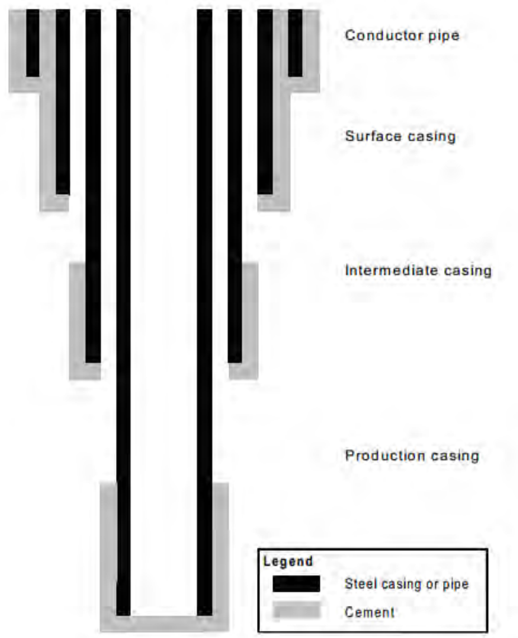
[174] Osborn, S.G., et al., 2011. "Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing." *Proceedings of the National Academy of Sciences.* Accessed February 12, 2012. http://www.pnas.org/content/108/20/8172

[175] Molofsky, Lisa J, J.A. Connor, S. K. Farhat, A.S. Wylie, Jr., T. Wagner, 2011. "Methane in Pennsylvania water wells unrelated to Marcellus shale fracturing." *Oil and Gas Journal*, December 5, 2011 edition, pp54-67. Accessed online April 16, 2012. http://www.cabotog.com/pdfs/MethaneUnrelatedtoFracturing.pdf

intermediate casing, yet another smaller diameter drill bit is used to drill the well to the target producing zone. Upon reaching the target extent of the well, production casing is put in place and cemented. Intermediate casing is not used in every situation due to variations in geologic conditions or state regulations. Additionally, the extent of cementing around each casing string varies based on geologic conditions or regulatory requirements.

Figure 4-2. Typical Oil or Gas Well Schematic, excluding the horizontal portion of the well (from API Guidance Document HF1)[176]



After the well is constructed, explosive charges are used to perforate the production interval of the well so that fluids can move between the production casing and the target producing formation. The well is then fractured in stages, as described previously in Section 2.

A number of steps are important to ensuring protection of groundwater during construction and throughout the lifetime of a gas well. These include:

- Testing of nearby water wells and surface waters prior to drilling to establish baseline water quality conditions;
- Proper formulation and monitoring of drilling mud mixtures to maintain pressure control of the well and stabilize the hole during drilling;
- Logging of the borehole during and after drilling to identify zones of freshwater and saltwater, oil- or gas-producing zones, and zones where cement may be lost to the formation;

[176] API. Hydraulic Fracturing Operations - Well Construction and Integrity Guidelines: API Guidance Document HF-1, 1st Edition. 2009. p. 5.

- Use of appropriate casing, couplings, and centralizers to ensure that the casing can withstand the various pressures to which it will be subjected during the process of drilling, cementing, hydraulic fracturing, and production;
- Proper cement placement techniques to ensure complete filling of the spaces around the casings;
- Use of a cement with adequate strength to withstand the various pressures to which it will be subjected during its lifetime;
- Allowing an adequate waiting time between cementing casing and additional drilling, to ensure that the cement achieves its full strength before proceeding;
- Logging of the cemented casings to ensure that the cement has completely filled the space around the casing and has formed an adequate bond to the casing and borehole wall;
- Using geological data collected during drilling to design the hydraulic fracturing treatment;
- Monitoring the effects of the hydraulic fracturing itself, both at the wellhead and at the land surface overlying the horizontal portion of the well;
- Monitoring pressures in the well and between the well casings during hydraulic fracturing and production phases; and
- Proper plugging and abandonment of the well once production ceases.

At present, North Carolina regulates construction and abandonment of oil and gas wells under two complementary sets of regulations: 15A NCAC 5D and 15A NCAC 2C .0100. Neither set of regulations includes detailed technical requirements related to the steps outlined above. North Carolina's oil and gas well construction standards in 15A NCAC 5D have not been modified substantially in decades. The well construction standards in 15A NCAC 2C .0100 were revised in 2009, but applicability to oil and gas wells was not a consideration in the rule revision process. Both sets of rules should be revised, relying on the best guidance currently available, to develop well construction standards for oil and gas activities, including horizontal drilling and hydraulic fracturing. There are no federal regulations pertaining to the construction of wells used for oil or gas exploration or production.

Water supply well construction

Proper construction of water supply wells helps protect the groundwater resource and the well user from contaminants that may be present in shallow groundwater, whether the contaminants are a result of pre-existing conditions or associated with gas exploration or production activities.

Construction of a water supply well is a simpler process than construction of a gas well. Generally only one or two stages of drilling are necessary and only a single string of casing is used. The casing may be either steel or polyvinyl chloride (PVC) pipe. The casing is grouted in place using either cement or bentonite clay. The casing and cement together are intended to prevent contaminants at the land surface or in shallower groundwater from entering the water-bearing zone of the well.

As with gas wells, several steps in the construction of water supply wells are critical to protection of groundwater and the well user during construction and throughout the lifetime of the water supply well:

- Proper siting of the well relative to potential contaminant sources;
- Use of appropriate casing, couplings, and centralizers to ensure that the casing can withstand the various stresses to which it will be subjected during the process of drilling and cementing;
- Use of proper grout materials to stabilize the casing and prevent migration of contaminants around the casing;
- Proper grout placement techniques to ensure complete filling of the spaces around the casing; and
- Proper plugging and abandonment of the well once it is no longer needed.

North Carolina's well construction standards for water supply wells in 15A NCAC 2C .0100 specify technical requirements for each of these steps. In addition, the North Carolina Well Construction Act (N.C. General Statute 87, Article 7) requires every newly-constructed private drinking water well to be permitted, inspected and tested by the local health department. The local health department reviews the proposed siting of the well, observes the grouting of the well and collects a water sample from the well once construction is complete. Water samples are tested for arsenic, barium, cadmium, chromium, copper, fluoride, lead, iron, magnesium, manganese, mercury, nitrate, nitrite, selenium, silver, sodium, zinc, pH and bacterial indicators. These test results may be useful in establishing baseline water quality, but testing does not include many of the chemicals that may be used or generated by oil and gas production activities, nor does it address all contamination sources that may be present in the vicinity of the well.

Potential releases to groundwater

Recent studies of the groundwater impacts of hydraulic fracturing have not produced clear evidence that hydraulic fracturing itself causes groundwater contamination. A number of studies have found groundwater contamination associated with oil and gas exploration and production activities generally – if not directly attributable to hydraulic fracturing. In fact, an advisory publication from the Penn State Extension Service flatly states, "Pollution of private water supplies from gas well activity has occurred in Pennsylvania."[177] These recent studies indicate that groundwater contamination from oil and gas production cannot be attributed to a single activity, but instead may be caused by a number of activities that occur in the life cycle of

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[177] Penn State College of Agricultural Sciences Cooperative Extension. *Water Facts #28: Gas Well Drilling and Your Private Water Supply.* Accessed February 6, 2012. http://extension.psu.edu/water/marcellus-shale/drinking-water/gas-well-drilling-and-your-private-water-supply-2/gas-well-drilling-and-your-private-water-supply/view

a gas well. Determining the specific cause of any such groundwater contamination incident requires detailed investigation of multiple lines of evidence.

An EPA investigation of groundwater contamination near Pavillion, Wyo. found methane of thermogenic origin and organic chemicals consistent with those used in hydraulic fracturing fluids in both monitoring wells and water supply wells.[178] EPA is still trying to determine the ultimate sources and routes of the contamination observed at Pavillion. The relevance of this study to hydraulic fracturing generally is unclear. From review of EPA's findings, it appears likely that inadequate casing and cementing of the gas wells played a role in the contamination. The hydraulic fracturing that occurred in Pavillion also involved injection of hydraulic fracturing fluids directly into the same formation tapped by water supply wells. The implications for hydraulic fracturing in North Carolina are also uncertain. To the extent well construction standards may be involved, we have already noted that North Carolina's well construction standards do not currently include the detailed technical requirements necessary to protect groundwater and the gas-producing zone. Unlike the Pavillion wells, most wells in the Triassic Basins of North Carolina are completed hundreds of feet above the target shale formations, but it is unclear whether this separation distance between the water supply wells and the target shale formations would be sufficient to protect groundwater from contamination that could result from hydraulic fracturing.

As noted earlier, we also do not know the extent of deep groundwater in the Triassic Basins and whether it has water quality sufficient to serve as a source of drinking water without treatment. If such a supply of drinking water did exist, the EPA investigation into Pavillion could have more relevance in North Carolina. In any case, North Carolina's groundwater regulations treat all groundwater in its natural state as a potential source of drinking water.

Osborn and others showed that water supply wells close to active exploration and production wells in the Marcellus shale have higher levels of dissolved methane than wells farther away.[179] Their study did not find constituents of hydraulic fracturing fluids in any of the water supply wells that were sampled. The methane found in water supply wells had an isotopic signature indicating that it originated from deep, thermogenic sources consistent with a Marcellus shale source, rather than from shallow biogenic sources (such as manure piles or decaying organic matter). However, no background groundwater samples were available to allow comparison to methane levels prior to the commencement of hydraulic fracturing operations and the study relied solely on stable isotope data for its conclusions.

In a report to the U.S. EPA, Echelon Applied Geoscience Consulting points out, "it is essential that a thorough characterization and definition of background groundwater quality is implemented to define pre-existing conditions prior to drilling activity. Stray gas migration incidents should be thoroughly investigated and supported by multiple lines of evidence,

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[178] EPA, 2011. *Investigation of Ground Water Contamination near Pavillion, Wyoming.* http://www.epa.gov/region8/superfund/wy/pavillion/EPA_ReportOnPavillion_Dec-8-2011.pdf (accessed January 16, 2012).

principally, geochemistry and analyses documenting a mechanism of migration." [180] This conclusion highlights the importance of obtaining good background groundwater quality data as well as a thorough understanding of the hydrogeology of the area before any gas well drilling or hydraulic fracturing operations begin.

Researchers at Pennsylvania State University studied water supply wells before and after drilling and hydraulic fracturing operations. Their study found that bromide levels in at least one water well increased after drilling or hydraulic fracturing and that "the increase in bromide was accompanied by increases in chloride, hardness and other indicators after drilling and fracking had occurred." The study also found that "a small number of water wells also appeared to be affected by disturbances due to drilling as evidenced by sediment and/or metals increases that were noticeable to the water supply owner and confirmed by water testing results."[181]

A study by the Groundwater Protection Council (GWPC) examined groundwater contamination investigations undertaken by the oil and gas regulatory agencies in Ohio and Texas. [182] The review covered groundwater investigations in Ohio over a 25-year period (1983-2007) and Texas groundwater investigations over a 16-year period (1993-2008). Both states have active oil and gas exploration and production industries, though Texas has greater levels of activity, and a much longer history of high-volume hydraulic fracturing. According to the GWPC study, large-scale hydraulic fracturing of the Barnett Shale in Texas began in 1986, with the first hydraulic fracturing of a horizontal well occurring there in 1992. Since 1986, more than 13,000 wells have been stimulated in the Barnett Shale alone. By contrast, only one horizontal well was hydraulically fractured in Ohio during the studied period; that well was fractured in 2007.

The GWPC study examined the ultimate causes of each groundwater contamination incident (as determined by the investigating state agency) and categorized the causes based on seven phases of exploration and production:

1. Orphaned wells and sites,
2. Site preparation, including construction of access roads, grading of well pads and excavation of pits,
3. Drilling and completion, including well drilling, casing and cementing, and handling of drill cuttings, mud and fluids encountered while drilling,
4. Well stimulation, including hydraulic fracturing of both vertical and horizontal wells,
5. Production, on-lease transport and storage, including on-site handling of oil, gas and produced water, repair and maintenance of the production well, and use of pits for waste handling and disposal during the production phase,

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[180] Baldassare, 2011.

[181] Boyer, Elizabeth W. et al. "The Impact of Marcellus Gas Drilling on Rural Drinking Water Supplies." *Publications*. The Center for Rural Pennsylvania. Accessed January 24, 2012. <http://www.rural.palegislature.us/documents/reports/Marcellus_and_drinking_water_2011_rev.pdf>

[182] Groundwater Protection Council, 2011. *State Oil and Gas Agency Groundwater Investigations And Their Role in Advancing Regulatory Reforms.* Accessed January 16, 2012. http://www.gwpc.org.

6. Waste management and disposal, including landfarming, landspreading, road application or disposal by injection wells, and
7. Plugging and site reclamation after production has ceased.

A summary of the contamination incidents grouped according to the phase of oil or gas production in which the authors determined contamination occurred is presented in Table 4-3.

Table 4-3. Summary of the Sources of Groundwater Contamination from Oil and Gas Production in Ohio and Texas

Phase	Number of Incidents	
	Ohio (1983-2007)	Texas (1993-2008)
Orphaned wells and sites	41	30
Site preparation	0	0
Drilling and completion	74	10
Well stimulation	0	0
Production, on-lease transport, and storage	39	56
Waste management and disposal	26	75
Plugging and site reclamation	5	1
Unknown	(none reported)	39

Role of diabase dikes and vertical faults in potential groundwater contamination

The unique geology and hydrogeology of the Triassic Basins of North Carolina suggests that there is a greater risk of groundwater contamination from oil and gas operations here than may be present in other shale gas plays. The Marcellus Shale in Pennsylvania lies at depths of roughly 10,000 feet. The deepest water supply wells in that area are generally no more than 600 feet deep, and it is not uncommon to encounter highly saline groundwater at depths of 600 to 750 feet.[183] By contrast, water supply wells up to 1,000 feet deep have been found in North Carolina's Triassic Basins, and the depth to saline water, if present at all, is unknown. Additionally, the shale that might be tapped for natural gas in the Triassic Basins of North Carolina lies at depths of 4,000 feet or less. These factors all point to a much greater potential for contamination of a future potential water supply.

As noted above, numerous near-vertical diabase dikes, and a lesser number of horizontal diabase sills, intrude into the sedimentary rocks of the basin. The edges of these diabase intrusions and the sedimentary rocks immediately adjacent to them are both highly fractured, and are therefore capable of yielding sufficient quantities of water to support water supply wells. Groundwater can often flow freely for great distances along the edges of these diabase intrusions, but when the diabase intrusions are relatively thick they tend to restrict groundwater flow in a direction perpendicular to the strike of the intrusions. These dikes and sills intruded from great depths beneath the sedimentary rocks in the basin and could act as

[183] Brian Grove, Chesapeake Energy. Personal communication, February 1, 2012.

conduits for migration of fracturing fluids if drilling or fracturing occurred in close proximity to them. It would therefore be necessary to conduct detailed investigation of the extent, depth and degree of natural fracturing of diabase dikes in the area before drilling or hydraulic fracturing is conducted. Detailed, site-specific models of the propagation of hydraulic fractures must also be considered in determining appropriate setback distances from diabase dikes.

Multiple near-vertical faults also cut through the sedimentary rocks of the Triassic Basins. These faults can occur in a variety of orientations, but the dominant fault orientations in the Triassic Basins of North Carolina are northwest-southeast and, to a lesser extent, northeast-southwest. The degree to which these faults may transmit water is not well understood and warrants additional investigation; if these faults transmit water, then these faults could serve as pathways that could connect deep groundwater with shallower groundwater and surface water.

Potential public health impacts

The different contaminants associated with oil and gas operations present varying degrees of potential public health risks. Without knowing the composition of chemicals that might be used in the process of developing natural gas in North Carolina, it is not possible to say what specific health risks the release of drilling chemicals into groundwater would pose.

North Carolina's groundwater quality standards are established based on the intended use of groundwater as a source of drinking water. These standards establish the maximum allowable concentration of contaminants that may be tolerated without creating a threat to human health or rendering the water unsuitable for its intended use. The current groundwater standards specify concentration limits for more than 140 constituents. For any constituent without an existing numeric standard, the standard is established by default at the practical quantitation limit. New standards may be established higher than the practical quantitation limit (the lowest level at which a laboratory may accurately measure the concentration of the contaminant) if an interested party provides sufficient toxicological and epidemiological data and other calculations to support a different standard.

Consumption of drinking water containing dissolved methane does not pose a public health risk. However, in high concentrations methane can pose a threat of asphyxiation because it displaces oxygen in the air. In addition, methane and oxygen in an enclosed environment, such as a house or other dwelling, can pose an explosion or fire hazard.

Conclusions related to groundwater

We recommend that the General Assembly require each oil and gas operator to obtain background groundwater quality data from existing water supply wells near the proposed drill site before drilling begins and to share this data with the regulatory agency. Each water supply well located within a distance determined by the horizontal extent of the hydraulically fractured well should be sampled and analyzed for dissolved methane, volatile and semi-volatile organic compounds, chloride, total dissolved solids, bromide, and dissolved metals.

In addition, the state needs to undertake further study of the routes of possible groundwater contamination resulting from oil and gas operations (including hydraulic fracturing). Study should focus on the potential role of vertical geological structures such as dikes and faults as well as mechanisms for preventing and diagnosing the cause of groundwater contamination, if warranted. At a minimum, a detailed hydrogeologic investigation should be performed at all sites where hydraulic fracturing is proposed to identify the horizontal and vertical extent of all faults and intrusions and their capacity to affect the movement of deep groundwater and hydraulic fracturing fluids.

D. Process wastewater

Wastewater characteristics

Volume generated and patterns of generation in time

The process of hydraulic fracturing generates two types of wastewater: "produced water" and "flowback." Produced water is the groundwater naturally found in shale formations. Contact with the shale causes groundwater in these formations to take on high levels of total dissolved solids as well as minerals including barium, calcium, iron and magnesium. Flowback consists of a combination of produced water with the fluids that are injected into the well by the drilling operator. During the days or weeks immediately following hydraulic fracturing, flowback makes up most of the wastewater that returns to the surface and consists primarily of the hydraulic fracturing fluids. The volume of flowback reported in the Marcellus shale in northern Pennsylvania ranges from 9 – 35 percent of the fluid pumped into a well for hydraulic fracturing.[184] During the remainder of the productive life of the well, a much smaller volume of wastewater is generated more or less continuously as the well produces gas; this wastewater is produced water.

Chemical characteristics of the wastewaters

Due to variations in geological conditions, the constituents in the flowback water from potential shale gas production sites in North Carolina may differ substantially from those found in currently active sites in Pennsylvania, Ohio or Texas. The specific formulation of hydraulic fracturing fluids used will also affect the characteristics of the flowback waters. Data from existing well fields can be used, however, to generally illustrate the broad categories of chemical characteristics that must be considered in managing wastewaters generated by gas production.

[184] NYSDEC, p. 5-99.

Table 4-4. Typical Range of Concentrations for Some Common Constituents of Flowback Water in Western Pennsylvania[185]

Constituent	Low (mg/l)	Medium (mg/l)	High (mg/l)	Average Concentrations in Seawater[186]
Total Dissolved Solids	66,000	150,000	261,000	34,580[187]
Total Suspended Solids	27	380	3,200	Not Reported
Hardness (as CaCO3)	9,100	29,000	55,000	Not Reported
Alkalinity (as CaCO3)	200	200	1100	Not Reported
Chloride	32,000	76,000	148,000	19,000
Sulfate	ND	7	500	2,700
Sodium	18,000	33,000	44,000	10,500
Calcium, total	3,000	9,800	31,000	410
Strontium, total	1,400	2,100	6,800	8
Bromide	720	1,200	1,600	67
Iron, total	25	48	55	0.0003
Manganese, total	3	7	7	0.0020
Oil and grease	10	18	260	Not Reported
Total radioactivity	ND	ND	ND	Not Reported

ND = Not Detected

Although not detected in the data from western Pennsylvania, naturally occurring radioactivity may also be present in produced water in any shale gas field. It is not yet known what levels of naturally occurring radioactivity may be present in produced waters, and thus in flowback water, from North Carolina shale deposits.

Bromide is a pollutant of concern, not because of its own toxicity, but because of its potential to cause toxic disinfection byproducts during chlorination of drinking water. Bromide is not removed by normal wastewater treatment, nor is it removed by conventional drinking water treatment plants. If wastewater containing bromide is discharged to surface waters supplying a downstream drinking water treatment plant, it can lead to the creation of toxic byproducts during the disinfection process. It is difficult to measure bromide concentrations in brine solutions such as produced waters due to extremely high chloride concentrations. EPA is attempting to develop a quantitative relationship between the levels of bromides discharged into water bodies and toxic disinfection byproducts in drinking water.

The constituents listed in Table 4-4 do not include the compounds that are added to the hydraulic fracturing fluid, any of which could be present in the flowback water. The industry has

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185 Gregory, K.B., et al. 2011. "Water Management Challenges Associated with the Production of Shale Gas by Hydraulic Fracturing." *Elements* v. 7 no. 3, pp. 181-186.

186 Hem, John. *Study and Interpretation of the Chemical Characteristics of Natural Water.* USGS Water Supply Paper 2254, 1989.

187 Calculated by DENR from total of constituents reported in Hem, 1989.

identified at least 44 chemicals used in shale gas production including the following: glutaraldehyde, quaternary ammonium chloride, tetrakis hydroxymethyl-phosphonium sulfate, ammonium persulfate, isopropanol, methanol, ethylene glycol, naphthalene and 2-butoxyethanol. Any of the chemicals used in hydraulic fracturing could be present in flowback water.

It is difficult to predict the exact composition of wastewater that would be generated by a hydraulic fracturing operation in North Carolina. The constituents in the wastewater are affected by both the characteristics of the shale play and the mixture of compounds used in the hydraulic fracturing fluids. For example, the produced waters from Barnett Shale in Texas are typically lower in total dissolved solids (TDS) concentration than those from the Marcellus Shale in Pennsylvania.[188] Oil, grease and volatile organic compounds are highly variable even within a particular formation. As a result, the flowback water from a North Carolina gas well may have a different makeup than the data cited above would suggest. It may not be possible to fully characterize flowback waters from shale gas operations in North Carolina until there is actual wastewater from a North Carolina hydraulic fracturing operation.

On-site storage of drilling fluids, hydraulic fracturing fluids, produced water and flowback

Often, on-site storage structures are used to provide temporary storage for drilling muds, hydraulic fracturing fluids, flowback, produced water, emergency overflow, oil and other fluids until they can be conveyed to a facility for disposal or reuse. On-site storage can be in pits excavated in the ground, or in above-ground containment systems such as steel tanks.

The failure of a tank, pit liner or the pipeline carrying fluid ("flowline") may result in contamination of surface water and shallow ground water. An accidental spill or release can have negative impacts on human health, wildlife, plants and ecosystems. Since environmental cleanup – especially where surface water or groundwater has been contaminated – is costly and time-consuming, prevention of releases is vitally important.

For excavated pits, infiltration of fluids into the ground is a serious concern. Typically, pit liners are constructed of compacted clay or synthetic materials like polyethylene or treated fabric that can be joined using special equipment. The GWPC study of contamination incidents associated with oil and gas operations found that unlined or inadequately constructed pits for drilling mud or produced water were one of the most common sources of groundwater contamination in Ohio.[189]

Under current North Carolina regulations, wastewater storage ponds are required to meet design standards to be protective of groundwater. Demonstration of liner specifications is required to ensure that maximum hydraulic conductivity or groundwater standards are not exceeded. Use of clay or synthetic liners or the use of predictive modeling of the groundwater may be used to demonstrate adequate protection.

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[188] Kelvin Gregory, Assistant Professor of Environmental Engineering, Carnegie Mellon University, personal communication, January 17, 2012.
[189] GWPC, 2011.

New systems have been developed that avoid the use of pits. One technology that is becoming more common is "closed-loop" fluid handling systems. These systems avoid the use of pits by keeping fluids within a series of pipes and tanks throughout the entire fluid storage process. Since fluid is never placed into contact with the ground, the likelihood of groundwater contamination is minimized.[190]

Disposal options for wastewaters

Four major options exist for disposal of wastewaters produced by oil and gas operations, including hydraulic fracturing operations: Class II injection wells: disposal by a publicly-owned treatment works (POTW) under a pretreatment program; reuse or recycling as fracturing fluids; and land application. A number of factors may make some of these options impractical or undesirable for use in the Triassic Basins of North Carolina.

Class II Injection Wells

One option used in other states for disposal of produced water and flowback water from hydraulic fracturing is by underground injection of the wastewater. EPA has delegated the authority to issue permits for injection wells under the federal Safe Drinking Water Act's Underground Injection Control (UIC) provisions to DENR's Division of Water Quality. The UIC program sets standards for several different classes of injection wells. Under the federal rules, a Class II injection well can be used to inject wastewater generated in the production of oil and natural gas. According to the EPA, approximately 80 percent of Class II injection wells in the United States are used for enhanced oil and gas recovery; the remainder are used for disposal of wastewater fluids from the shale gas exploration and production process into the original oil- or gas-bearing formation or a similar formation.[191] Federal regulations require Class II injection wells to be constructed and operated in a manner that is protective of underground sources of drinking water.

N.C. General Statute 143-214.2(b) prohibits the use of wells for waste disposal. To preserve options for future water supply, state rules also classify all groundwater in North Carolina as a potential source of drinking water. As a result, state law does not currently allow permitting of Class II injection wells. The nearest Class II injection wells are in western Virginia, but the UIC permits issued by EPA only allow those wells to accept wastewaters that are generated from the oil or gas production with which they are associated.

Even if North Carolina law were changed to allow underground injection of waste, it is not clear that injection wells would be a feasible option for managing produced waters from a gas well in the Triassic Basins. The areas with potential for natural gas development have not been sufficiently characterized to determine whether the formations would be suitable for disposal of shale gas production wastewater. The sedimentary rocks of these basins generally have very low permeability, and natural fractures are responsible for nearly all of the permeability and

[190] FracFocus.org, "Fracturing Fluid Management." Accessed January 31, 2012. http://fracfocus.org/hydraulic-fracturing-how-it-works/drilling-risks-safeguards.
[191] EPA. "Class II Wells – Oil and Gas Related Injection Wells (Class II)." 2011. Accessed January 20, 2012. http://water.epa.gov/type/groundwater/uic/class2/index.cfm

groundwater movement in these basins. As mentioned previously, sedimentary rocks in the Sanford sub-basin tend to have very low permeability due to the presence of fine-grained material commonly occurring within the spaces between the larger grains. Instead, most of the ability of these formations to produce or receive water is due to fractures in the rock. Disposal by injection into fractured rock presents difficulty in predicting the fate and transport of the injected wastewaters. These conditions suggest that Triassic Basins in North Carolina generally do not have suitable hydrogeologic conditions for disposal by injection.

States with both active oil and gas production and active Class II injection wells do not allow injection into the production zone in order to prevent degradation of the oil or gas-producing zones.[192] The exception is to allow disposal in the oil or gas producing formation in such a way that enhances the recovery of oil or gas. Otherwise, produced wastewaters are typically disposed of in other formations or zones that do not produce oil or gas.

The Coastal Plain of North Carolina is underlain by formations that could have properties more suitable for disposal of process wastewaters. However, multiple aquifers in the Coastal Plain are actively used as sources of drinking water, and others have the potential to be used as sources of drinking water and are protected as such under 15A NCAC 2L. 0200.

Federal UIC rules do not allow injection of wastewater into Underground Sources of Drinking Water (USDW). Although North Carolina classifies all groundwater as a potential drinking water source, the EPA definition of USDW excludes aquifers containing groundwater with total dissolved solids (TDS) levels of 10,000 mg/L or greater.[193] A limited number of areas in the Coastal Plain of North Carolina are known to have groundwater having TDS of 10,000 mg/L or greater. However, those areas are at least 120 miles away from the Deep River Triassic Basin. The relatively shallow depth of some of these aquifers may not provide sufficient separation from potential drinking water supplies to allow for the safe disposal of produced waters. Thus even adopting the EPA's definition for drinking water aquifers may not open up options for disposal of wastewaters by deep well injection.

If an appropriate underground disposal site could be identified, successfully siting and constructing a disposal well and associated infrastructure would require a thorough hydrogeologic evaluation of subsurface conditions thousands of feet below ground as well as assessments of environmental impacts to surface features. This assessment process would be both costly and time-consuming. Even the coastal plain aquifers that fall outside the EPA definition of USDW may not have hydrogeologic conditions suitable for injection, due to their generally low permeability.

Administratively, creation of the necessary regulatory framework to allow injection of wastewater from drilling operations would require development of a state regulatory program for Class II wells. Since North Carolina law prohibits underground injection of wastes, the state has no standards for siting, construction and operation of waste injection wells. The program

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[192] Based on conversations with Class II injection well programs in Montana, Colorado, Alabama, and Louisiana. January 2012.

[193] Code of Federal Regulations, Title 40, Part 144.3

change would require the state to re-apply to the EPA for approval of the revised UIC program; that process can be lengthy.

Disposal by publicly-owned treatment works or centralized waste treatment facility

Wastewaters from oil and gas exploration and production may also be sent to a Publicly-Owned Treatment Works (POTW) (also known as a municipal wastewater treatment plant) or a Centralized Waste Treatment (CWT) facility. CWTs accept wastes from many types of industry for treatment, and then discharge treated wastewater to a POTW under a pretreatment permit from the POTW, or discharge to surface waters under an NPDES permit held by the CWT.

Three basic scenarios exist for wastewater management through POTWs or CWTs:

(1) wastewater from oil and gas production operations may be treated onsite by the generator of the wastewater before final disposal to the POTW, which holds an NPDES permit,
(2) it may be transported to a centralized waste treatment facility (CWT) for pretreatment before final disposal to the POTW, or
(3) it may be transported to a CWT for treatment and discharge to surface waters under an NPDES permit held by the CWT.

North Carolina has eight CWTs permitted through local pretreatment programs. North Carolina also has one CWT permitted for direct discharge through the NPDES program, but the facility plans to shut down the CWT operation in the near future.

To receive wastewater from oil and gas production, a CWT that discharges treated wastewater under an NPDES permit would have to request a major permit modification due to the changed characteristics of the wastewater. NPDES permit writers are required to develop technology-based limits on a case-by-case basis. The NPDES permit would need to be modified to take into account pollutants in the new wastewater stream that were not addressed when the CWT effluent guidelines were developed.

Due to the high strength and unique characteristics of certain industrial wastewaters, including wastewaters generated by oil and gas production, pretreatment of wastewater is necessary in order to protect the receiving POTW and its receiving stream. Federal rules require pretreatment in order to prevent pass-through of pollutants to the receiving stream in amounts greater than the National Pollutant Discharge Elimination System (NPDES) permit limit or stream standard, prevent interference with the wastewater treatment processes, and promote the beneficial reuse of biosolids. [194]

EPA has established standards for each pretreatment category in 40 CFR Parts 400-471. Since EPA did not consider the hydraulic fracturing industry when developing the categorical standards, the standards may not address all of the pollutants of concern generated from shale gas production. Based on local site-specific factors, a POTW with a pretreatment program may establish limitations for pollutants not covered by the federal regulation and may require more stringent limits for covered pollutants. A pretreatment facility may be able to provide targeted

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[194] 40 CFR 403.2

treatment for specific pollutants of concern associated with natural gas extraction and make the treated wastewater much more acceptable to the POTW.

In North Carolina, any POTW that accepts wastewater from a significant industrial user (SIU) must have a state-approved pretreatment program. An SIU is an industrial user that:

1. discharges an average of 25, 000 gallons per day or more of process wastewater;
2. contributes 5 percent or more of the treatment plant capacity for flow or biochemical oxygen demand (BOD), total suspended solids (TSS) or ammonia;
3. is subject to categorical regulations described above; or
4. is designated as an SIU by the POTW because the industry's wastewater could adversely affect the operation of the POTW.

One of the tools used to accomplish the goals of the pretreatment program is the Headworks Analysis (HWA). The HWA calculates the amount of pollutants that can safely enter the POTW while meeting the goals of the program. Three criteria are examined in the conventional pollutant HWA:

- Pass-through calculations evaluate compliance with NPDES permit limits or water quality standards and serve to protect the stream into which the POTW discharges.
- Inhibition calculations evaluate allowable loadings that will not inhibit or interfere with the treatment process and serve to protect the treatment plant.
- Sludge calculations ensure that the biosolids produced are acceptable for land application. Organic parameters are evaluated using a separate spreadsheet and this evaluation addresses worker health and safety by including an evaluation of explosivity, permissible exposure limit (PEL) and short-term exposure limit (STEL) concentrations.

Each POTW that provides pretreatment performs the headworks analysis based on the characteristics of the individual wastewater treatment plant. Results will vary from POTW to POTW. Prior to accepting wastewater from any industrial source, the POTW must use sound scientific data and best professional judgment to determine if a particular waste stream will be compatible with the treatment plant and to decide whether to accept the waste stream. The SIU may not begin discharging to the POTW prior to receiving an Industrial User Permits (IUP) from the POTW. The IUP must be approved by DWQ and must contain conditions and limits so that the treatment plant effluent will still meet water quality standards, NDPES permit limits and not cause aquatic toxicity.

Typical parameters for the HWA are: biological oxygen demand (BOD), TSS, ammonia, arsenic, cadmium, chromium, copper, cyanide, lead, mercury, molybdenum, nickel, selenium, silver, zinc, total nitrogen and total phosphorus. Site-specific data is used to calculate removal rates. Literature removal rates are available if there is insufficient data or a removal rate cannot be calculated because a majority of the data is below the quantitation limit of the analytical method.

Many of the compounds that may be present in shale gas production wastewater are not included in the typical HWA parameters. Where applicable toxicity data on aquatic life or human health is available, the Division of Water Quality may be able to provide an aquatic life or human health protective value for these compounds. It should be noted that for a number of the identified constituents, data availability is limited. Often, the Classification and Standards Unit of the N.C. Division of Water Quality can provide an aquatic life or human health standard for these compounds. A removal rate based on scientific literature can be obtained from EPA's Risk Reduction Engineering Laboratory (RREL) Treatability Database. Other sources for data may be the HWAs of other North Carolina POTWs.

Even in the absence of specific water quality standards for all expected pollutants, the POTW can use the information in the Headwaters Analysis as a starting point for conducting inhibition and toxicity studies. Laboratory studies can be conducted using actual treatment plant influent and produced water to determine the compatibility of the wastewater with the treatment plant.

Some shale gas production wastewater also has naturally occurring radioactivity. North Carolina has dealt with the issue of treating radioactive wastewater in a wastewater treatment plant before. In the past, the issue arose because of the disposal of drinking water treatment residuals in which naturally occurring radioactive materials had been concentrated. In this context, the N.C. Radiation Protection Section (Department of Health and Human Services, Division of Public Health) clarified the requirements in 49 CFR Part 173 Subpart I regarding the general requirement for shipments and packaging of Class 7 (Radioactive) Materials.[195] The federal rule specifically states in Part 173.401 (b) (4) that this subpart does not apply to: "Natural material and ores containing naturally occurring radionuclides which are not intended to be processed for use of these radionuclides, provided the activity concentrations of the material does not exceed 10 times the values specified in 173.436." It is not yet known whether produced waters from North Carolina shale deposits will contain other hazard classes that would then be subject to the requirements in Part 173.423, Requirements for Multiple Hazard Limited Quantity Class 7 (Radioactive) Materials.

Land application

Land application is another option used in many states for disposal of wastewaters produced by oil and gas operations. In many western states, oil and gas production wastewaters are used for de-icing or dust control on roads.

In North Carolina, land application of wastewater requires treatment of the wastewater to meet specified quality standards prior to disposal. North Carolina has existing standards for both land application and infiltration systems; those can be found in 15A NCAC 02T .0500 and 15A NCAC 02T .0700, respectively. The rules and individual permit conditions specify setbacks, land-application rates, and the timing of land application to protect groundwater, surface water, and public health. North Carolina rules could potentially allow for land-application or infiltration of wastewater from gas production by irrigation of vegetated land, disposal in an infiltration basin, or beneficial reuse. In each case, the applicant would need to demonstrate compliance with current technical criteria

[195] Beverly Hall, Chief, Radiation Protection Section, November 27, 2006. Memorandum to DWQ on disposal of wastewater associated with water supply wells with potential radiological components.

Surface irrigation systems involve controlled surface application of wastewater effluent on a vegetated land surface by using spray heads or a drip system. These systems use the natural ecosystems to incorporate the wastewater effluent. The effluent is absorbed into the atmosphere through evaporation or volatilization, into the soil through filtration and into plants through nutrient uptake and the degradation of microorganisms.

Infiltration basins involve the controlled application of wastewater effluent to the ground and rely on infiltration as the primary mechanism of disposal. Application methods include rotary distributors, spray beds and infiltration basins. High-rate infiltration systems land apply treated effluent at rates greater than 91 inches per year (in/yr) for coastal areas and 873.6 in/yr for non-coastal areas. A standard infiltration basin is any basin that does not exceed the threshold to be considered a high-rate system. Application rates are based on soil properties and surficial aquifer characteristics. For high-rate systems, groundwater quality standards are designed to be met through more stringent effluent nutrient limits, and more stringent setbacks are in place. It is highly unlikely that site conditions in the Triassic Basin will provide sufficient infiltration for a basin to be considered a high-rate infiltration basin.

It is also possible that the shale gas production wastewater could be treated to meet reclaimed water standards established in 15A NCAC 02U. Reclaimed water is highly treated wastewater effluent that can be used for beneficial purposes such as for golf course irrigation, firefighting or cooling water. Wastewater that meets reclaimed water standards may be permitted for reuse with reduced reporting and setback requirements. The possibility of reuse of the wastewater produced by oil and gas production will depend on the cost of treatment to meet the reclaimed water standards and the availability of potential users for the reclaimed water.

Wastewater produced by a natural gas operation would be classified as an industrial wastewater and permitting requirements for land application of the wastewater would be consistent with those applied to any other industrial wastewater. The state’s land application rules set minimum design standards for the wastewater treatment and disposal system; establish setbacks from features such as streams; and require the applicant to demonstrate adequate operation and maintenance procedures.

Disposal of wastewater generated by oil and gas production by land-application or infiltration poses some significant challenges in the Triassic Basin due to the wastewater characteristics and the soil and subsurface conditions typically found in the area. All land-application wastewater systems require a site evaluation to ensure that the site can handle the waste. Due to the high variability in the chemical characteristics of the wastewaters and its classification as an industrial wastewater, a site-specific hydrogeologic evaluation and groundwater modeling would be required for each potential disposal site. The evaluations would consider the proposed method of treatment, available land area and subsurface conditions on the site to determine if the wastewater can be applied in a manner protective of the groundwater.

High salinity can present a potential problem in using wastewater recovered from oil and gas production for crop irrigation. Water salinity refers to the total amount of salts dissolved in the water, primarily from calcium, magnesium and sodium ions dissolved in the water. A high level of salts in irrigation water reduces water availability to the receiving crop and can reduce yield.

When sodium salts dominate the total salinity, the forces that naturally bind clay particles together in the soil are disrupted, causing clay particles to expand and reduce the permeability of the soil.

Considering the chemical characteristics of flowback water presented in Table 4-4, the concentration of both sodium and total chlorides presents another potential limitation on the suitability of land application of produced waters. Sodium may have adverse effects on the very shallow soils found in the Triassic belt of North Carolina. A combination of efficient drainage and flushing of the soil by water is often used to leach salts from the profile. The soils of this region have a hard subsurface with low permeability. The applied salts may accumulate on the surface layers for a long time, causing the topsoil to further degrade and affecting plant growth adversely.

Soil characteristics are also a key component to the proper design and management of non-discharge systems. Soils in the Triassic Basin typically have low hydraulic conductivity, which limits their utility as non-discharge systems. Loading rates for permitted facilities surrounding the Sanford sub-basin ranged from 20 to 80 inches per year. Using a 20 to 80 inches per year range of application rates, an anticipated average of five (5) million gallons per well, and a conversion of 27,000 gallons for an acre-inch, an expected range of 2.3 to 9.3 acres would be required to dispose of the average volume of waste from each well. (Please note that variation in volumes of wastewater generated at a well site and on-site soil characteristics will greatly impact the amount of land necessary to manage wastewater, and actual land requirements could be outside of the estimated range).

An existing rule, 15A NCAC 2T .0113(a)(10), provides an exemption from regular permitting for land application of “drilling muds, cuttings and well water from the development of wells or from other construction activities including directional boring.” This exemption was intended to address wastes generated by water well construction and utility borings. Without amendment, however, the rule could allow essentially unregulated disposal of these wastes from gas wells.

It is not likely that produced waters could be used for road de-icing or dust control under North Carolina’s land application rules. Unlike many western states where “roadspreading” of wastewater is allowed, North Carolina has a large network of streams and wetlands; road drainage features would in many instances direct the wastewater to surface waters.

Potential for recycling/on-site pre-treatment techniques

On-site treatment of the flowback or produced water prior to disposal or transportation to a permitted wastewater treatment facility may be required as part of wastewater management. If wastewater management includes either discharge to a municipal or private wastewater treatment system not owned by the oil and gas developer, or if the water is managed as part of a land application system owned by the gas developer, it is likely that on-site treatment will be necessary. Due to the variations in flowback water quality, and requirements for disposal, a site-specific evaluation will be necessary to determine the necessary treatment system. However, due to the high dissolved solids found in flowback water at other sites, it is likely that membrane filtration, reverse osmosis, thermal distillation or other high level treatment strategies will be necessary to achieve the treatment criteria needed for disposal. These types of treatment systems are proven to effectively remove dissolved solids from a wastewater; however, these treatment systems also produce a concentrate of dissolved solids that will need to be managed.

According to some sources, Chesapeake Energy's Aqua Renew technology can make 95 percent of hydraulic fracturing wastewater clean enough to be reused[196] by a filtering process that uses a 20-micron filter.[197] The remaining percentage is sludge treatment residual that must be disposed of in a landfill, through land application, or other means. North Carolina regulations applicable to treatment residuals are discussed below. The filtration process removes suspended solids that form a filter cake composed of sand and rock material. This material is disposed of in permitted landfills.[198] Chesapeake no longer disposes of any produced water by wastewater treatment plants that discharge to rivers or streams in Pennsylvania. The water produced during flowback operations is collected and stored in onsite storage tanks. The benefits of recycling wastewater include using less freshwater for hydraulic fracturing, reducing the impact on local water supplies, reducing the amount of truck traffic for hauling water, reducing noise and air pollution due to truck traffic, and reducing the costs of operation.[199]

Instances can occur where there is more water than can be readily processed and reused, typically during large rain events. In these instances, Chesapeake has used an evaporative distillation treatment system, provided by a local contractor, along with Class II injection wells to dispose of the temporary surplus. [200]

Closed-loop recycle systems are defined in 15A NCAC 02T .1000 as wastewater systems where nondomestic wastewater is repeatedly recycled back through the process in which the wastewater was generated. Requirements for closed-loop recycle systems are established in 15A NCAC 02T.1000. Closed-loop recycle systems do not include recycling of wastewater from groundwater remediation systems though an injection well or infiltration gallery specifically covered by administrative code for groundwater remediation systems (15A NCAC 02T .1600). The recycling of wastewater recovered during flowback for use as an injectant would not be allowed due to GS 143-214.2(b), which prohibits the injection of wastes into groundwaters of the state.

While recycling wastewaters as fracturing fluids has proven to be an effective wastewater management option for Chesapeake Energy in Pennsylvania, the usefulness of this practice in the Triassic Basins of North Carolina may be limited due to geologic and hydrogeologic conditions noted above. The shale that is being used for fracturing in Pennsylvania lies at depths of roughly 10,000 feet. The deepest water supply wells in that area are generally no more than 600 feet deep, and it is not uncommon to encounter highly saline groundwater at

[196] Downing, Bob. "Chesapeake unveils system to recycle waste water from 'fracking' drill sites." *Akron Beacon Journal Online*. February 9, 2012. Retrieved April 15, 2012 from http://www.ohio.com/news/local/chesapeake-unveils-system-to-recycle-waste-water-from-fracking-drill-sites-1.264011.
[197] Brian Grove, Chesapeake Energy. Personal communication, February 1, 2012.
[198] Ibid, February 1, 2012.
[199] Ibid, February 1, 2012.
[200] Ibid, February 1, 2012.

depths of 600 to 750 feet.[201] By contrast, water supply wells up to 1,000 feet deep have been found in North Carolina's Triassic Basins, and the depth to saline water, if present at all, is unknown. Additionally, in some areas, the shale that might be tapped for natural gas in the Triassic Basins of North Carolina lies at depths of 3,000 feet or less. These factors all point to a much greater potential for contamination of a future potential water supply.

Disposal options for treatment residuals

Residuals generated as part of oil and gas production must be managed to ensure protection of surface and groundwater resources. The Division of Water Quality's (DWQ) Residuals Management Program regulates the treatment, storage, transportation, use and disposal of residuals as specified in 15A NCAC 02T: Waste Not Discharged to Surface Waters. Under these rules, residuals have been defined as any solid, semi-solid or liquid waste, other than effluent or residues from agricultural products and processing, generated from a wastewater treatment facility, water supply treatment facility or air pollution control facility permitted under the authority of the Environmental Management Commission (EMC). Rules specific to Residuals Management are located in Section .1100 of Subchapter 02T. Depending on the quality of the residuals, the generator may land-apply the residuals for beneficial use or dispose of the residuals in a surface disposal unit. Residuals not meeting minimum requirements could be further processed until requirements are met, or sent to a permitted landfill or incinerator for disposal.

The quality of the residuals is critical to assure that proper management practices are matched with the residuals to assure that they are land applied, or disposed of, in a safe manner. The quality of the residuals is dependent on the characteristics of the wastewater being treated, and the type of wastewater treatment and sludge stabilization process used. Residuals quality requirements for land application include demonstration that the residuals are non-hazardous, metals and pathogen concentrations do not exceed a ceiling limit, micro nutrient values for nutrient management are met, and prescribed methods for pathogen and vector attraction reduction are met.

E. Surface water impacts and stormwater management

Oil and gas exploration and production activities present environmental risks to other industrial and construction activities already regulated under existing state and local stormwater management programs. Some of the activities associated with oil and gas exploration and production, however, are exempt from federal stormwater permitting requirements that apply to other industrial and construction activities in North Carolina.

Stormwater flows can impact the environment in several ways: stormwater can carry pollutants directly or indirectly from land surfaces to surface waters; stormwater may cause containment structures (such as pits storing wastewater) to overtop, causing pollutants to reach surface waters; and a high rate and volume of stormwater runoff can physically damage streams by eroding stream banks and scouring the stream bottom.

[201] Ibid, February 1, 2012.

As rainfall runs across the surface of the industrial or construction areas the rainwater picks up any pollutants that may be on the surface and carries those pollutants to streams, rivers and lakes. This is especially true for stormwater runoff from asphalt, concrete, gravel and dirt roads, other impervious surfaces, outdoor industrial activity and earthen construction sites, where any material collected on the ground in the course of normal operations may be washed into a nearby surface water body. In the event of a spill due to equipment malfunction or operator error, large amounts of pollutants can be delivered to the receiving waters in a very short amount of time.

Second, unusually heavy rainfall has the potential to overwhelm the excess storage capacity of open top tanks or pits containing process chemicals or waste materials as well as berms that may be enclosing a well pad, and can cause the unintended release of the harmful materials along with the excess rainfall. The New York Department of Environmental Conservation reviewed several spill incidents in the hydraulic fracturing industry, and reports on the Chesapeake Energy spill in Pennsylvania, stating that,

> "On April 19, 2011, an uncontrolled flow of hydraulic fracturing fluid occurred during fracture stimulation of Chesapeake Energy's Atlas 2H well in LeRoy Township, Bradford County...a failure occurred at a valve flange connection to the wellhead, causing fluid to be discharged from the wellhead at high pressure. Approximately 60,000 gallons of fluid were discharged to the well pad, of which 10,000 gallons flowed over the top of the containment berms. A portion of this fluid made its way into an unnamed tributary of Towanda Creek. The wellhead failure is under investigation to determine the precise cause of the breach. The wellhead was pressure-tested after installation and after each hydraulic fracturing stage prior to the breach. According to Chesapeake officials, it passed all tests. The discharge of fluid from the well pad was caused by the failure of stormwater controls on the well pad due to extraordinary precipitation and other factors."[202]

Incidents like this can cause pollutants in high-brine flowback waters to enter freshwater streams and rivers. Other pollutants contained in hydraulic fracturing fluids could be released as well, which also could pose threats to the aquatic environment. As noted above, the potential impacts of some hydraulic fracturing additives are not completely understood.

Third, runoff typically increases where hard surfaces and paved areas are constructed. Standard industrial site layout is designed to remove rainwater from the working area as quickly as possible so as not to impede the safe conduct of production operations. The result is more runoff volume, delivered more quickly, to the receiving water. The sudden increase in volume can cause stream bank and streambed erosion that degrades the habitat quality of the water body. For small rain events or small sites, the habitat degradation can be transient and the receiving waters may be sufficiently resilient to recover quickly. Variation in flow volume with the seasons and in response to large rain events is natural and some scouring of the streambed

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[202] NYDEC, pp. 10-2 – 10-3.

becomes part of the natural variability of the aquatic habitat. But for large projects or sizable sediment loads, the effects can be long-term and result in permanent stream degradation. So in addition to the chemical pollutants and eroded sediment originating from the well pad, increased in-stream erosion from artificially increased flow volumes can degrade streams.

A well pad has the potential to generate all three stormwater problems. While the pollutant generation and transport mechanisms are similar to other industrial and construction activities, oil and gas exploration and production activities are not regulated to the same extent as other industrial activities. The potential impacts of stormwater runoff from a drilling site include:

- Contamination of surface waters with hydraulic fracturing fluids
- Contamination of surface waters with sediment, nitrogen compounds and other pollutants
- In-stream erosion
- Habitat degradation

Erosion and sedimentation issues during production and following reclamation of well pads

Erosion and sedimentation from the construction of the well pad and from subsequent production activities deserve special attention. Sediment has been identified as the largest water quality problem in North Carolina. Environmental agencies use a variety of ways to measure sedimentation pollution: 1) the presence of visible sedimentation deposited in a stream bed; 2) total suspended solids (TSS) in the stormwater discharge entering a creek; and 3) in-stream turbidity. The potential for excess sediment in a creek can be mitigated through both operational and structural stormwater practices.

For sediment originating in erosion of the well pad itself, either during construction or during operations, the following preventive measures may be appropriate:

- Stabilize the disturbed earth as soon as possible after or even during phases of the grading operation with fast germinating grasses. Rigorously maintain these areas once stabilized.
- Coordinate the grass stabilization with the sequence of construction and site activities to afford maximum continuing protection.
- Employ sediment capture basins to keep eroded sediment on site.
- Continue inspections and maintenance of the sediment control measures even during periods of less intense activity, such as the production phase.

The federal Energy Policy Act of 2005 exempted oil and gas activities from federal construction stormwater permitting requirements under the Clean Water Act. Those permitting requirements specifically address sedimentation pollution and turbidity impacts associated with construction activities. State sedimentation control requirements still apply; compliance with the North Carolina Sedimentation Pollution Control Act, N.C. General Statute 113A, Article 4, will require the industry to implement many of the measures described above in the construction of well pads and other infrastructure associated with exploration and production of natural gas.

Post-development runoff

To prevent in-stream erosion and habitat degradation due to increased stormwater runoff and the resulting increased flow in the receiving water, the following preventive measures may be appropriate:

- Structural stormwater controls should provide enough freeboard to accommodate a large design rainfall.
- Structural stormwater controls should incorporate a peak flow shaving element in the outlet structure design. Standard outlet structure design typically accomplishes peak flow reduction with submerged orifices, floating outlets, or constraining weirs.
- Qualified personnel should assess the morphology of nearby streams in order to evaluate how much excess flow the stream can accommodate before in-stream erosion is probable. This assessment should be either accomplished by regulatory staff, or subject to regulatory review and approval.
- After site operations cease, the potential for site erosion and for increased stormwater runoff remains unless close out activities include stabilization of the abandoned well pad. Re-vegetation of the site should be required as part of close out requirements.

It appears that the greatest risk of stormwater pollution and receiving water impacts is during the more intense stages of natural gas extraction, such as clearing and grading, mobilization and set up, hydraulic fracturing and re-fracturing, and demobilization and knock down. Once the site is producing natural gas, stormwater runoff may carry less risk, assuming the well pad has been successfully stabilized, remaining production activities have adequate containment, and operators provide ongoing inspection, maintenance and repair. Production with reduced staff or no staff, however, increases the chance of stormwater impacts due to a lack of resources for prevention activities and for immediate response to a stormwater pollution emergency.

Stream and wetland impacts

Streams and wetlands are protected under both state and federal law because of the many beneficial functions they provide. Streams support aquatic life, commercial shellfish harvesting, fishing, recreation, agriculture and water supply. Wetlands provide stormwater and flood storage, recharge of groundwater reservoirs, filtration and storage of sediments, nutrients and other pollutants, shoreline protection and habitat for aquatic organisms and wildlife.

Activities associated with the exploration and production of wells for oil and gas can result in stream and wetland impacts similar to any construction and development project. Well site development involves a range of infrastructure including drilling pads, reserve and mud pits, freshwater ponds, flowback water ponds, access roads, dikes, berms, equipment ramps, borrow pits, disposal areas, staging areas, water lines, gathering lines and gas transmission pipelines. As in any construction project, stream and wetland impacts occur most commonly from the placement of material in a stream or wetland to support a structure (such as a culvert or road crossing), damming of a stream channel to create a pond or lake, disturbance to the bottom or sides of a stream (e.g. streambank stabilization) or filling or draining of wetlands.

If a gas exploration or production activity requires a federal permit under Section 404 of the Clean Water Act because of impacts to a stream or wetland, it also requires a certification that the project will be consistent with state water quality standards. The certification is commonly called the 401 Certification by reference to the section of the Clean Water Act that created the certification requirement. The Water Quality Certification (WQC) program in DENR's Division of Water Quality provides the review required for issuance of a Section 401 Certification. To receive a 401 Certification, the applicant must show that:

- No practical alternative exists to the stream or wetland impacts.
- The stream and wetland impacts have been minimized.
- Mitigation has been provided for stream and/or wetland impacts.
- The project does not degrade groundwater or surface waters.
- The project does not result in cumulative impacts that cause or will cause a violation of downstream water quality standards.
- The project provides protection of downstream water quality standards through the use of on-site stormwater control measures.

Environmentally sensitive site design

Appropriate selection and design of the well site can be a major tool in the protection of North Carolina's streams, rivers and lakes. With respect to gas production, major site location selection criteria will clearly involve geology of the site and commercial viability, but environmental considerations also have a role in siting and designing production-related infrastructure. Potential operators might consider the following factors:

- Are nearby surface waters especially particularly sensitive? Examples might be waters classified for drinking water supply or carrying an outstanding resource water designation.
- Are nearby or downstream waters the home of any threatened or endangered species?
- Is the topography surrounding the proposed well pad conducive to the construction of measures for effective control of runoff?
- Are there wetlands or buffers nearby that require particular attention in siting infrastructure?
- Can the well site accommodate any necessary setbacks? For example, oil and gas programs in other states include separation or setback requirements from a variety of features including water supply watershed boundaries, water supply wells, creeks and rivers, wetlands and floodplains. Separation criteria can be especially effective in addressing the pollutants conveyed in stormwater runoff.

Once a site location has been selected, environmentally sensitive site design will include the structural stormwater control measures necessary to protect surface waters from the pollutants, sediment and increased flow volume generated by activities at the well pad. These measures should be designed to control the following sources of potentially problematic stormwater runoff constituents:

- Sediment from site grading and subsequent well pad erosion;
- Subsoil and topsoil stockpiles;
- Initial drilling fluids, muds and cuttings;
- Fuel and petroleum products, as well as petroleum hydrocarbons originating down hole;
- Equipment wash water, detergents and solvents;
- Proppants and hydraulic fracturing fluids with known and unknown constituents;
- Produced water;
- Increased runoff volume

Stormwater management measures should also acknowledge the importance of operating practices and sequence of activities on the well pad. During site development there can be intense activity, conducted 24 hours per day. Site clearing and grading, mobilization and set up, hydraulic fracturing and re-fracturing, and demobilization all represent stages of activity similar to the most intense construction and industrial activities. During these times of focused, intense activity, management actions can increase, or decrease, the risk of discharge of stormwater pollutants.

Even during the less intense periods of production, or of stand-by or close out or capping, when the risks are less there is still a need for evaluation of the character of the risks, and of appropriate preventive measures and operating practices.

Surface spills and releases from the well pad

At similar industrial sites, standard good practice requires the development of a written site-specific spill plan including plan elements addressing on-site spill response equipment, personnel training, identification of on-site personnel in charge of executing the spill plan, immediate action in the form of containment, control and countermeasure responses, and reporting to environmental authorities. The purpose of rapid clean-up is, in part, to prevent the transport of any spilled material into nearby waterways by stormwater runoff. No federal regulations require hydraulic fracturing operations to have a comprehensive spill plan to address the several different types of fluids potentially on site, but a number of state oil and gas programs require operators to have an emergency response plan.

A rain event concurrent with a spill may transport pollutants directly to a receiving water, leaving little time to react to the spill. Effective response actions may be impeded if the spill occurs during a heavy rain.

Spills and releases during transportation and storage

As with transportation of any fluids or wastes, the transport of hydraulic fracturing chemicals, drilling muds, flowback water and other wastes associated with oil and gas exploration and production present the risk of spills or leaks from truck accidents or pipeline leaks. The magnitude of truck traffic necessary to support hydraulic fracturing increases the risk of spills from truck accidents. This risk could be reduced by relying instead on pipelines for transport of water and wastewaters, but pipelines still may leak or rupture if not adequately constructed or maintained. The environmental impacts of such spills vary based on the type and volume of fluid spilled, the accessibility of the site to emergency response crews, and the preparedness of the emergency response crew to deal with the particular substance that is spilled. There is obvious concern with spills of diesel fuel, hydraulic fracturing additives and wastewaters, but less obvious issues include spilling untreated raw water into pristine high quality waters, such as an example cited by Pennsylvania officials of spillage of water from the Susquehanna River into a headwater trout stream.[203]

Potential public health impacts

Stormwater pollution can impact public health through a limited number of mechanisms. Stormwater discharges polluted with carcinogens or toxics can accumulate in the tissue of fish and shellfish, and can be passed on to humans that consume them. Even less worrisome pollutants like sediment or turbidity can degrade the natural aquatic habitat and make the resident fish susceptible to disease organisms that may be transmitted to humans.

In general, public water supplies are effective at providing clean potable water and incidents of human impacts from public water supplies are rare. However, increased pollutant content in the raw water source could increase treatment costs for the public utility. Potential impacts to public water supply are addressed more fully in Section 3.A of this report.

Conclusions related to surface water impacts and stormwater management

We recommend conducting baseline data collection for surface waters. Pre-drilling surface water monitoring data should be collected for areas proposed for drilling to establish baseline water quality information. The extent and location of data collection should be determined as drilling blocks are established.

The impacts of stormwater discharges from oil and gas exploration and production are substantially similar to the impacts from the construction and industrial activities that occur in North Carolina today. Oil and gas exploration and production can disturb large areas of land to develop impervious well pad sites, creating significant impacts related to sedimentation and erosion, water quality pollution, increased peak discharges, increased frequency and severity of flooding, and other stormwater concerns.

However, unlike existing construction and industrial activities, oil and gas exploration and production activities are exempt from the requirements of the National Pollutant Discharge Elimination System (NPDES) stormwater permit program under the federal Clean Water Act

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[203] Pennsylvania Department of Environmental Protection, personal communication, February 3, 2012.

unless there has been a documented water quality standard violation, or release of a reportable quantity of oil or hazardous substance. Since North Carolina has relied on the federal stormwater permitting programs to manage industrial stormwater impacts, the state is not prepared to effectively manage stormwater impacts associated with oil and gas production.

We recommend that the General Assembly authorize a state stormwater regulatory program for oil and gas activities, including requirements for stormwater permitting, inspections and compliance activities.

F. Land application of oil and gas wastes

Some states allow the disposal of oil and gas industrial wastewaters and the associated solids and sludges, as well as drilling cuttings and muds, by land application. Land application is a form of bioremediation that usually refers to the application of wastes or byproducts to soils or crops at specific concentrations per acre. The objective is to allow the soil's naturally occurring microbial population to transform and assimilate waste constituents in place and utilized by a receiving crop. Several terms are used to describe this waste management approach, which can be considered both treatment and disposal.

Landfarming is a bioremediation method sometimes used for the treatment of contaminated soils or waste sludges and muds. Land farming often means repeated applications of wastes to the soil surface, whereas land spreading and land treatment are often used interchangeably to describe the one-time application of wastes to the soil surface or incorporation into the top several inches of the soil.

Roadspreading is the application of the wastewater or solids to roads for the purpose of de-icing, dust control or to increase traction.

See Section 4.D, Process wastewater, for information concerning land application and road spreading of wastewaters. As previously noted, 15A NCAC 2T .0113(a)(10) provides an exemption from regular permitting for land application of "drilling muds, cuttings and well water from the development of wells or from other construction activities including directional boring." While this exemption was intended to address these wastes generated by water well construction and utility borings, it could be interpreted to allow essentially unregulated disposal of these wastes from any type of well – including gas wells.

If natural gas extraction and production occurs in North Carolina, we recommend that the General Assembly prohibit the unregulated land application of solid waste and wastewater from oil and gas activities because of the environmental impacts and the lack of sufficient capability to dispose of all waste generated.

Given the chemical variability, drilling wastes (such as cuttings and muds) should be disposed of in a lined landfill unless additional regulations are put in place to require chemical characterization of the waste. A landfill continues to be the most protective method of solid waste disposal and also reduces possible or perceived aesthetics issues.

Petroleum-contaminated soils from spills or leaks associated with exploration and production can be land-applied by permit from the Division of Waste Management's Underground Storage Tank Section.

It is not likely that the wastewaters and solids from the exploration and production of gas in North Carolina will be generally suitable for beneficial land application, roadspreading or other recycling uses. DENR should, however, assist the industry in identifying wastes and byproducts that are suitable for recycling purposes. Additional resources within DENR will be needed for personnel with industry specific expertise.

G. Air quality impacts

A variety of processes and equipment used in oil and gas extraction and production can have air quality impacts. Air emissions associated with oil and gas activities may include a number of potential contaminants with differing health and environmental consequences. The air quality impacts of an oil and gas operation will depend on a number of different factors, including: the specific type of air contaminants emitted; the volume of those emissions; the siting of the operation; and the geography and meteorology of the area.[204]

Air emissions

Air contaminants (commonly referred to as air pollutants) are classified and regulated based on the physical state of the pollutant and the effect the pollutant has on human health and the environment. Four general classifications of pollutants have been established by the federal Clean Air Act and generally adopted by the states: criteria pollutants, toxic pollutants (also known as hazardous air pollutants or HAPs); other Clean Air Act (CAA) regulated pollutants; and greenhouse gases (GHG). The classifications are spelled out in more detail in the lists and discussion below.

- Criteria Pollutants
  - Particulate matter (PM-10 and PM-2.5)
  - Carbon monoxide (CO)
  - Sulfur dioxide (SO_2)
  - Nitrogen oxides (NO_x)
  - Ozone
  - Lead (Pb)
- Hazardous Air Pollutants (HAP)
  - Organic pollutants, including dioxins and furans
  - Inorganic pollutants, including metals
  - Acid gases
- Other CAA Regulated Pollutants
  - Volatile organic compounds (VOC)

[204] This section of the report analyzes the potential impacts of hydraulic fracturing based on North Carolina's air quality program; there can be considerable variations between state programs.

  - Fluorides
  - Sulfuric acid mist (H_2SO_4)
  - Reduced sulfur compounds (including hydrogen sulfide (H_2S))

- Greenhouse Gases (GHG)
  - Carbon dioxide (CO_2)
  - Nitrous oxide (N_2O)
  - Methane
  - Hydrofluorocarbons
  - Perfluorocarbons
  - Sulfur hexafluoride (SF_6)

Criteria Pollutants

Criteria pollutants (listed above) are the pollutants for which National Ambient Air Quality Standards (NAAQS) have been established. Federal rules, adopted by the U.S. Environmental Protection Agency (EPA), set the NAAQS at ambient air concentrations that are generally accepted to be protective of human health and the environment.[205] Several different regulatory tools are used to achieve the NAAQS. At the state level, the Clean Air Act requires development of a state implementation plan (SIP) for achieving the standard for each pollutant. The SIP typically includes emission standards for sources that emit the particular criteria pollutant, but may also include other measures.[206] EPA also sets federal New Source Performance Standards (NSPS) for new, modified or expanded sources of a criteria pollutant and the state implements New Source Review (NSR) permitting requirements for those sources.

Hazardous Air Pollutants

Hazardous air pollutants (HAPs) have acute, chronic and carcinogenic toxic effects on human health. The HAPs regulated under federal rules are listed in Section 112(b) of the Clean Air Act. The North Carolina air quality program enforces the National Emission Standards for Hazardous Air Pollutants (NESHAP) with respect to sources in North Carolina. The national emissions standards apply only to the types of sources specifically listed for regulation under Section 112 of the Clean Air Act and do not apply to every potential source of hazardous air pollutants. The national standards are technology based – that is, each standard identifies specific air pollution control technology or level of control required for that particular type of pollution source; the technology selection then determines the emissions limits that go into the air quality permit.

DAQ also addresses many of the federally listed hazardous air pollutants (and additional toxic air pollutants that are regulated only by the state) under state-adopted acceptable ambient level (AAL) guidelines. The guidelines have been developed based on exposure effects on human health. The state program to control toxic air pollutants requires a demonstration that

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[205] Criteria pollutants are also frequently used as surrogates for hazardous air pollutants (HAPs); for example, controlling particulates can provide reductions in emissions of metals and controlling volatile organic compounds (VOCs) can provide reductions in organic HAP emissions.

[206] Under some circumstances (including state failure to develop an approvable plan), EPA can develop a federal implementation plan (FIP) for a state.

toxic air emissions above a certain emission rate will not exceed the acceptable ambient level at the property boundary of the facility or operation.

The HAPs specifically identified from natural gas operations include benzene, toluene, hexane, xylenes, ethylene glycol, methanol, ethyl benzene and 2,2,4-trimethylpentane.[207]

Other CAA regulated pollutants

Other CAA regulated pollutants are primarily regulated through the Best Achievable Control Technology (BACT) component of the NSR permitting program although some of these pollutants are regulated by specific NSPS. More discussion about BACT is presented under NSR permitting.

Greenhouse gases

Greenhouse gases (GHG) are somewhat unique in that the gases were not listed as pollutants under the Clean Air Act or its implementing regulations until EPA adopted New Source Review (NSR) rules for GHGs in June of 2010. The rulemaking followed an EPA finding that greenhouse gases in the atmosphere endanger both the public health and the environment for current and future generations.[208] The Title V permitting requirements from the Clean Air Act Amendments (CAAA) of 1990 would ultimately be used to enforce the GHG emission limitations developed under the NSR program.

Emission sources associated with natural gas extraction and production, including venting and flaring

A variety of emission source types can be associated with natural gas, from exploration through production. Many of these sources are reciprocating internal combustion engines (RICE) or combustion turbines (CT) for producing electricity or operating drilling equipment. During production of the natural gas, these emission sources power pumps and compressors to process the gas to pipeline quality. The production process also involves the use of glycol dehydrators, compressors, storage vessels and other equipment that may emit air pollutants. In addition to the production equipment, emission sources associated with hydraulic fracturing would include the fracturing chemicals, mobile sources (trucks and other heavy equipment) and methane (a powerful GHG) that may escape from the wells. Open tanks and pits can also be potential sources of VOCs and HAPs.

Methane gas may be released from the shale formation at several points during exploration or production. The majority of these methane releases, however, occur during well completion and gas production. Completion involves preparing the well, installing production tubing and associated tools in addition to any other necessary preparation including installation of the well casing. When methane gas is released during this process or during initial gas production, the industry typically handles the releases in one of three ways: venting, flaring or green completion. Venting simply allows the methane emissions to escape into the atmosphere. The

[207] http://www.epa.gov/ttn/ecas/regdata/RIAs/oilnaturalgasfinalria.pdf, pp. 4-13, 4-19.

[208] EPA's authority to make the endangerment finding – a necessary precondition for regulation under the Clean Air Act --was upheld by the United States Supreme Court in *Massachusetts* v. *EPA,* 549 U.S. 497 (2007).

methane also carries additional VOCs and HAPs that are contained in the gas stream. Flaring is a means of burning the methane and contaminants, releasing primarily water vapor and carbon dioxide. While carbon dioxide is a greenhouse gas, methane has a CO2 equivalency of 25, so flaring reduces the greenhouse potential of completion operations by a factor of 25. While this is an improvement in well completion from the greenhouse gas standpoint, flaring wastes the energy of the flared gas while still generating CO2 emissions. From an air quality perspective, the preferred alternative is what is known as "green completion." In this process, methane is captured and stored or transported from the well to ultimately be included in the pipeline quality natural gas system. From an industry perspective, the primary drawback with a green completion is that it can add cost and time to putting a well into production.

As various states have addressed natural gas activities, several have estimated emissions coming from the operations. The New York Department of Environmental Conservation developed a draft generic environmental impact statement (GEIS) for natural gas drilling in the Marcellus Shale, and revised the GEIS several times in response to a series of public comment periods. The Revised Draft Supplemental Generic Environmental Impact Statement (SGEIS) released on Sept. 7, 2011, estimated potential emissions from the different stages of gas production and the potential impact on compliance with national ambient air quality standards and state toxic standards. The New York SGEIS concludes that additional pollution controls may be necessary for the diesel completion equipment engines and the older tier drilling engines (used for drilling, liquid and gas pumping, natural gas compression and potentially a variety of other uses) in order to comply with the 24-hour fine particulate (PM2.5) standard and the 1-hour NO2 standard. Particulate traps can be used to reduce PM2.5 emissions; selective catalytic reduction reduces NO2 emission.

The SGEIS also estimates that statewide NOx emissions could be increased by 3.7 percent from the hydraulic fracturing operations and as much as 10.4 percent in the upstate area where the Marcellus Shale is located. These increases in NOx emissions raise concerns for the impact on ozone concentrations and the state's ability to attain and maintain compliance with the federal ozone standard.

Pennsylvania is in the process of collecting 2011 emission data from the owners and operators of natural gas production and processing operations in unconventional shale formations across the state. The emission data was due to the Pennsylvania Department of Environmental Protection by March 1, 2012. The emission data will become part of the state's comprehensive emission inventory due to EPA by Dec. 31, 2012. These and other efforts will provide North Carolina with valuable information for understanding the potential emissions from natural gas production activities and the impact of those emissions on air quality in the state.

Emissions and regulatory applicability

Combustion sources, such as reciprocating internal combustion engines and combustion turbines, are sources of criteria pollutants, hazardous air pollutants, greenhouse gases and potentially sulfuric acid mist. As a result, both source categories are covered by various emissions standards under the state implementation plan or SIP (which sets out the state air quality standards necessary to meet national ambient air quality standards); federal new source performance standards; state and federal requirements for sources of toxic air pollutants; and other federal engine standards. Standards applicable to an operation requiring new source review permitting are discussed below.

Natural gas production operations, including those listed below, are primarily regulated by federal new source performance standards (NSPS) and national emissions standards for hazardous air pollutants (NESHAP). In 1985, EPA set new source performance standards for emissions of volatile organic compounds (VOCs) and sulfur dioxide from natural gas processing facilities. EPA only recently proposed new source performance standards for other oil and natural gas operations. On Aug. 23, 2011, EPA proposed new source performance standards for emissions of volatile organic compounds (VOCs) and sulfur dioxide from a broader range of oil and natural gas exploration and production activities. As proposed, the standards would include operational requirements for completion of hydraulically fractured natural gas wells. EPA originally proposed to adopt a final NSPS rule by Feb. 28, 2012, but extension of the original comment period has delayed action beyond that date. [209] Affected sources include: gas wellheads, centrifugal compressors, reciprocating compressors, pneumatic controllers, storage vessels and sweetening units. Until the proposed rules go into effect, no federal new source performance standards apply to emissions from these natural gas exploration and production activities.

The amended NESHAP, 40 CFR Part 63, Subpart HH, regulates hazardous air pollution emissions from "Oil and Natural Gas Production Facilities." Affected facilities include, among others: glycol dehydration units, storage vessels with the potential for flash emissions, and compressors intended to operate in volatile HAP service.

Many of the chemicals used in the production of natural gas from hydraulic fracturing are proprietary, but may include VOC and volatile HAP. Currently, there are no federal or state regulations for the control of VOC or volatile HAP from hydraulic fracturing chemicals.

Methane is the primary component of natural gas and burns cleaner than other fossil fuels, producing lower levels of greenhouse gases such as CO_2. Although CO_2 emissions may be lower, methane is four times more powerful than CO_2 as a GHG. There are no federal or state regulations for the control of methane or other GHG from wells or other gas leaks with the exception of Prevention of Significant Deterioration (PSD) permitting requirements that may apply.

Mobile sources

An increase in heavy-duty truck traffic is associated with many stages of natural gas production. The increased truck traffic results in higher NOx, VOC and PM2.5 emissions in the area near the operation. In the New York SGEIS, the conclusion was that the resulting increase was less than 1 percent over the baseline emissions. States generally have limited control over emissions from on-road mobile sources. Typically EPA sets fuel efficiency and emission standards for on- and off-road engines. North Carolina does have anti-idling and fugitive dust regulations that may

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[209] Federal Register /Vol. 76, No. 163 /Tuesday, August 23, 2011 / Proposed Rules p. 52799

apply to vehicle operations at a natural gas exploration and production site. Also, in the event that NSR permitting is required, emissions from mobile sources may have to be considered.

Air quality permitting requirements

Air quality permitting in North Carolina is a combination of state and federal requirements. The North Carolina Division of Air Quality (DAQ) has delegated authority to issue air quality permits under the federal Clean Air Act. As a result, most air quality permits issued by DAQ are federal permits that can be enforced by the state and EPA. The exceptions would be permits issued under state-only requirements such as the state air toxics rules, odor control standards and open burning regulations.

State-only permits

Facilities that are classified as small or synthetic minor based on their potential to emit criteria pollutants or hazardous air pollutants obtain state-only construction and operation permits. In this case, the terms “small” and “synthetic minor” refer to the facility’s classification by reference to permitting requirements under Title V of the Clean Air Act. Under Title V, major air pollution sources require a federal operating permit; a source is generally considered a major source if it emits 100 tons per year (tpy) of a criteria pollutant and 10/25 tpy of individual/aggregate HAP emissions. Small facilities are those that do not have the potential to emit air pollutants over the major source thresholds. Synthetic minor facilities take permit restrictions to limit emissions below the Title V major source thresholds. The permit restrictions can include limits on annual hours of operation or volumes of production, types and/or quantities of fuels burned, or raw materials, among others. Without those limits, the facility would be a major source under the Title V permitting program. The state-issued permits can include SIP or federal emission control requirements for criteria pollutants or hazardous air pollutants as well as state-only enforceable requirements.

Title V Operating Permits

The Clean Air Act amendments of 1990 established a new federal operating permit program for major sources. Facilities permitted under the Title V program go through a higher level of public and EPA oversight as compared to state-only permits. The Title V permitting program was intended to consolidate all Clean Air Act requirements in one document. The permits can include state and federal emission control requirements for criteria pollutants or HAPs. In North Carolina, Title V operating permits also include state-only requirements that can only be enforced by the state. Permit conditions related to control of criteria pollutants or federally regulated HAPS can be enforced by both the state and EPA; conditions based on state-only requirements are only enforced by the state. In the oil and gas sector, a Title V permit would only be required for a natural gas processing facility (if it is a major source).

New Source Review Permits

New Source Review (NSR) permits are issued to major sources or for major modifications to an existing source. The NSR permitting program was an original part of the Clean Air Act and applies differently depending on whether the proposed project will be located in an area designated as attainment or non-attainment for any given criteria pollutant. A non-attainment designation means the area is out of compliance with one of the national ambient air quality standards.

In attainment areas, Prevention of Significant Deterioration (PSD) permits are issued for the purpose of maintaining the attainment status of the area. This goal is achieved using two primary tools: best available control technology (BACT) requirements and ambient air quality analyses.

BACT is defined as:

> "an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this chapter emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning, clean fuels, or treatment or innovative fuel combustion techniques for control of each such pollutant."[210]

Air quality analyses are performed on the proposed facility or modification to estimate the increase in the ambient concentration of criteria pollutants with the goal of protecting the attainment status of the area where the proposed facility would be located. The analyses use state-of-the-art air dispersion models, predicted emission rates and actual meteorological data and terrain conditions. In certain circumstances, air quality analyses are required for visibility impacts in areas such as national parks and wilderness areas.

In non-attainment areas, Non-attainment Area New Source Review (NAA NSR) permits are issued for the purpose of improving the air quality in the non-attainment area. This goal is also achieved using two primary tools: lowest achievable emission rate (LAER) and emission offsets.

LAER is defined as:

> "(A) the most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or (B) the most stringent emission limitation which is achieved in practice by such class or category of source, whichever is more stringent."[211]

Emission offsets are reductions in emissions of the limiting pollutant that are used to offset the increased emissions of a new or modified facility. Emissions offsets are typically generated in the non-attainment area in which the proposed facility would be located. Emission offsets are usually greater than the anticipated increase from the proposed facility or modification. Offsetting emissions reductions can be obtained from the facility requesting modification or from reductions at other facilities in the area.

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[210] USC Title 42, Section 7479, Paragraph (3)
[211] USC Title 42, Section 7501, Paragraph (3)

As noted above, EPA has only recently proposed new source performance standards for sources related to natural gas exploration and development, particularly hydraulic fracturing and wellhead standards. Until those standards become final, only natural gas processing facilities have applicable federal emission standards. Air emissions from the currently unregulated sources associated with natural gas production may, however, affect the permitting of other industrial facilities in the Triassic Basin counties if those sources affect the area's ability to attain an air quality standard.

There are currently no non-attainment areas in the airshed of the Triassic Basin. However, the 2012 attainment designations for ozone are based on the current ozone standard of 75 ppb. EPA undertook a review of that standard two years ago with the intent of potentially adopting a lower, more protective value. The national Clean Air Scientific Advisory Committee has recommended a more restrictive standard in the range of 60-70 ppb. The Clean Air Act requires EPA to review the national ambient air quality standards every five years; the ozone standard is due for review in 2013 and a final EPA decision is expected in 2014.

If EPA accepts the committee's recommendation and adopts a new ozone standard within the 60-70 ppb range, much of the area in the Triassic Basin could be designated non-attainment for ozone. Areas that have previously been designated non-attainment include all or part of Wake, Durham, Orange and Chatham counties. Since the ozone standard is based on an eight-hour average, even short-term increases in NOx emissions in these areas could contribute to an increase in ozone formation and future non-attainment designations. It should be noted that North Carolina is a NOx limited state; increases in VOC emissions have much less influence over ozone formation than increases in NOx emissions. From the perspective of ozone non-attainment, NOx emissions should be the primary focus of any state emission reduction strategy associated with natural gas development and production.

North Carolina will be able to learn from other states that have experience with issuing air quality permits for sources related to exploration and production of oil and gas. For example, Ohio Environmental Protection Agency issued a final general air quality permit for production operations at shale gas well sites in Ohio. The general permit covers a variety of emissions sources found at most shale gas well sites, including internal combustion engines, generators, dehydration systems, storage tanks and flares. It contains emissions limits, operating restrictions and monitoring, testing and reporting requirements. Applicants have to meet the criteria of the general permit in order to qualify for this streamlined permitting approach.

Potential public health impacts

The air quality standards enforced by the North Carolina Division of Air Quality are health-based standards. As mandated by the Clean Air Act, EPA sets national ambient air quality standards at levels considered to be protective of human health. Although the federal hazardous air pollution standards are technology-based emission standards, Section 112 of the Clean Air Act Amendments of 1990 requires EPA to evaluate the residual health risk after the technology standards have been met. Many natural gas production activities have been exempt from federal hazardous air pollutant and NSPS standards, however, and EPA has only recently proposed rules to apply to those activities. Until EPA finalizes the standards proposed in August 2011, those activities continue to be exempt from federal standards.

The North Carolina toxic air pollution program uses acceptable ambient levels (AALs) established by the North Carolina Scientific Advisory Board to ensure that emissions of toxic air pollutants have no long-term health consequences. A source must demonstrate that the AALs are met at the property boundary to prevent adverse health impacts to people occupying or using nearby property.

Limited ambient air monitoring has been conducted near natural gas operations. The Arkansas Department of Environmental Quality conducted limited monitoring in the Fayetteville Shale region of northeastern Arkansas. The study concluded that concentrations of NOx were not measured above the instrument's detection level. The monitoring did not result in VOC concentrations above the instrument's detection level at natural gas well sites or compressor stations. However, daily average and 15-minute rolling average concentrations of 678 ppb and 5,321 ppb, respectively were observed near the drilling sites. The study recommended that future monitoring studies use instruments with lower detectible limits, and instruments that can measure individual VOC compounds.

A National Oceanic and Atmospheric Administration (NOAA) led study in Colorado found elevated pollutants near natural gas fields. Based on data collected mostly in 2008, the study found that emissions of methane and benzene had been underestimated from the gas operations. The study concluded that gas production infrastructure may be leaking twice as much methane to the atmosphere as had been previously thought; researchers found that the Colorado oil and gas fields were losing 4 percent of total gas produced as opposed to 2 percent. Using ambient monitoring data, benzene emissions were estimated to be between 385 and 2,005 metric tons – significantly higher than previous estimates of between 60 and 145 metric tons.[212] Researchers also found that some other source contributed to benzene emissions – most likely cars and trucks.

A three-year monitoring study by the Colorado School of Public Health found benzene, ethylbenzene, toluene and xylene near wells. The lead author of the study used EPA methods to estimate increased risk of cancer and acute illness, particularly for people living near the wells during the short-term well completion periods.[213]

An environmental consultant, Wolf Eagle Environmental, was retained by the town of DISH, Texas to perform ambient air sampling near the town and a number of natural gas compressor stations in the area. The results of the sampling were compared to Effects Screening Levels (ESLs) of the Texas Commission. The study found that ambient concentrations of benzene, dimethyl disulfide, methyl ethyl disulphide, "ethyl-methylethyl" [sic] disulfide, trimethyl benzene, diethyl benzene, methyl methyl ethyl benzene, tetramethyl benzene, naphthalene, 1,2,4-trimethyl benzene, m&p xylenes, carbonyl sulfide, carbon disulfide, methyl pyridine, and

[212] http://researchmatters.noaa.gov/news/Pages/COoilgas.aspx
[213] http://www.sciencedaily.com/releases/2012/03/120319095008.htm

"diemethyl" [sic] pyridine exceeded their respective ESLs. The report notes that there is no other heavy industry in the vicinity of the sampling.[214]

A NOAA study in Utah is aimed at explaining high wintertime ozone levels in the sparsely populated Uintah Basin. Ozone is a pollutant typically found in the summer in areas with high concentrations of people, industrial development and traffic. However, ambient monitors in the Uintah Basin found ozone levels as high as 140 parts per billion in the winter of 2011. This is compared to the ozone NAAQS that is currently 75 parts per billion. The six-week long NOAA study is looking at ozone precursor chemicals and meteorological conditions favorable to the formation of ozone.[215]

Conclusions related to air quality impacts

Natural gas production presents some unique air quality challenges, given limited federal regulation of oil and gas production and current implementation of the state air toxics program. As mentioned above, the state air toxics program requires a source of state-regulated toxic air pollutants to demonstrate compliance with the AALs at the property boundary. Shale gas production often occurs under a lease of property that may be owned and in some cases occupied by another person. If natural gas production occurs on a residential property or farm, the property owner or occupant may be exposed to unhealthy concentrations of toxic pollutants. We recommend that DENR evaluate the existing policy to determine whether it represents adequate protection under scenarios where natural gas production is occurring on residential properties or farms.

As better emission estimates are developed for potential oil and gas development and production in North Carolina, we recommend that DENR evaluate potential impacts on ozone levels in the region, including the increases in emissions from truck traffic, well drilling and production.

We also recommend that DENR collect pre-drilling air emissions data for areas proposed for drilling, at a distance determined through additional research.

H. Impacts on fish, wildlife and important natural areas

While only a limited amount of research has been conducted on the specific effects of natural gas production on fish, wildlife and important natural areas in the Triassic Basins of our state, biologists and ecologists have a good understanding of the types of impacts that affect species and habitats of the Triassic Basin. The potential impacts range from contact with hydraulic fracturing fluids and wastewater to forest fragmentation and sedimentation of surface waters. This section begins with descriptions of the important lands and species of the area underlain by the Triassic Basins, followed by the potential impacts posed to these natural resources of the state by oil and natural gas exploration and production.

[214] http://townofdish.com/objects/DISH_-_final_report_revised.pdf
[215] http://www.esrl.noaa.gov/csd/news/2012/114_0307.html

Publicly owned lands in North Carolina's Triassic Basins

State, federal and local government agencies own and manage significant natural areas throughout the Triassic Basins. These properties are managed for a number of different public purposes including recreation, conservation of sensitive natural lands and species, and to provide the ecological and economic benefits associated with forests, open space and clean water. The data on public lands provided in this section and shown on Figures 4-2, 4-3 and 4-4 does not include all publicly and privately owned natural areas that provide ecological benefits. For example, the dataset does not include city parks or privately owned game lands managed by the N.C. Wildlife Resources Commission (NCWRC) through the Game Lands Program. Some of these privately-owned conservation areas include significant acreage; Progress Energy has 14,000 acres of land around Harris Reservoir in the Game Land Program. Although this land is in private ownership, Progress Energy permits public access for hunting. It would be difficult to capture a complete list of such privately owned lands, but it is important to note that these types of privately owned lands can provide both recreational and ecological benefits that could be impacted by natural gas extraction and production.

The U.S. Army Corps of Engineers owns two key pieces of land in the area underlain by the Triassic Basins: Jordan Lake and Falls Lake. The NCWRC manages lands adjacent to the two reservoirs as part of the Game Land Program. These reservoirs and the surrounding properties provide recreational activities such as boating, swimming, fishing, biking, camping and hiking. The reservoirs also supply water for neighboring communities, aid in flood and water quality control and provide habitat for fish and wildlife. Other significant natural areas in the Triassic Basin include the Pee Dee National Wildlife Refuge and a part of the Uwharrie National Forest (located in the Wadesboro Sub-basin of the Deep River Basin).

State-owned lands have been acquired for a number of complementary purposes: to conserve and protect examples of the state's natural beauty and ecological features of statewide significance; to provide outdoor recreational opportunities in a safe and healthy environment; and as sites for environmental education promoting stewardship of the state's natural heritage. In addition to state parks, state-owned lands in the Triassic Basins include lands owned by University of North Carolina - Chapel Hill and two National Historic Landmarks: Duke Homestead and Town Creek Indian Mound. National Historic Landmarks are nationally significant historic places designated by the United States Secretary of the Interior because they possess exceptional value or quality in illustrating or interpreting the heritage of the United States.

Local governments conserve lands for the many of the same reasons. Wake and Durham counties have open space lands in the Durham Sub-basin of the Deep River Triassic Basin. Wake County's Lake Crabtree County Park is also in the area.

Lands owned by local, state or federal governments within the Dan River Basin, the northern portion of the Deep River Basin, and the southern portion of the Deep River Basin are shown in the next three figures.

Figure 4-3. Publicly Owned Lands in the Dan River Triassic Basin

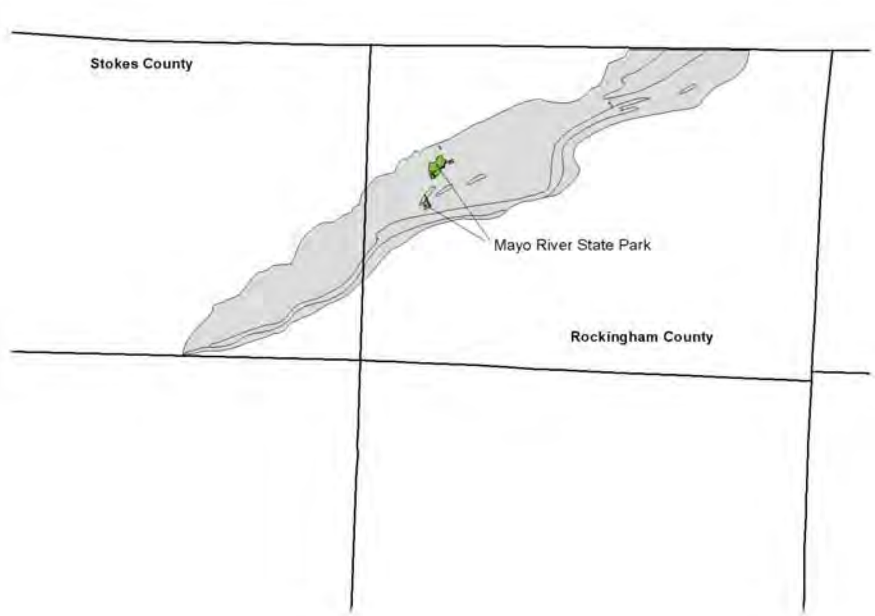


Figure 4-4. Publicly Owned Lands in the Northern Portion of the Deep River Basin

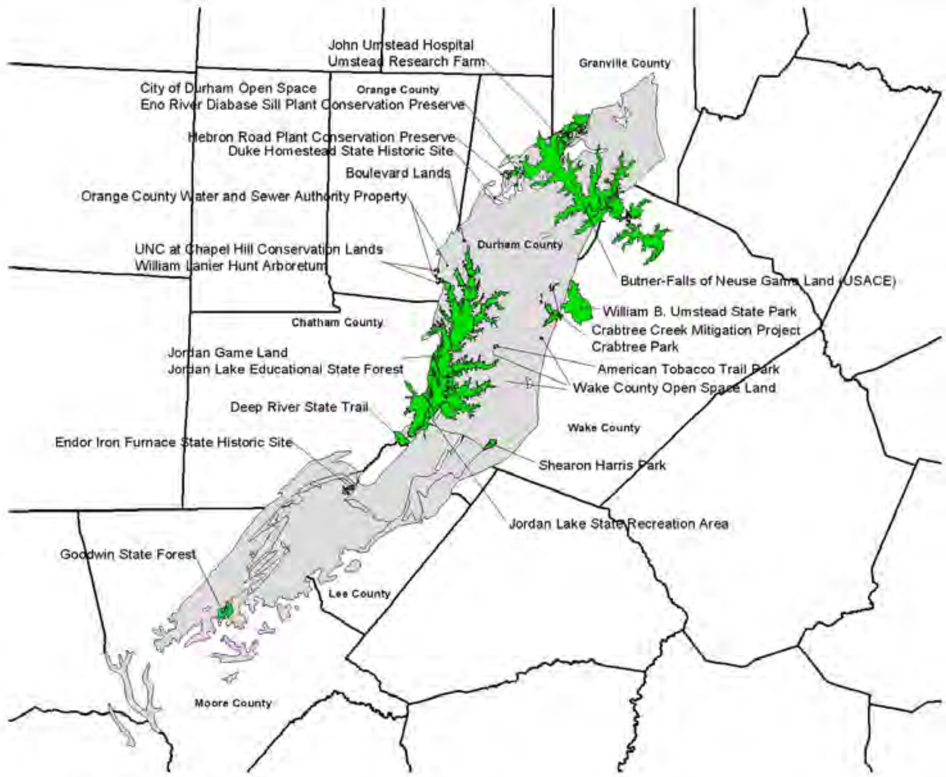
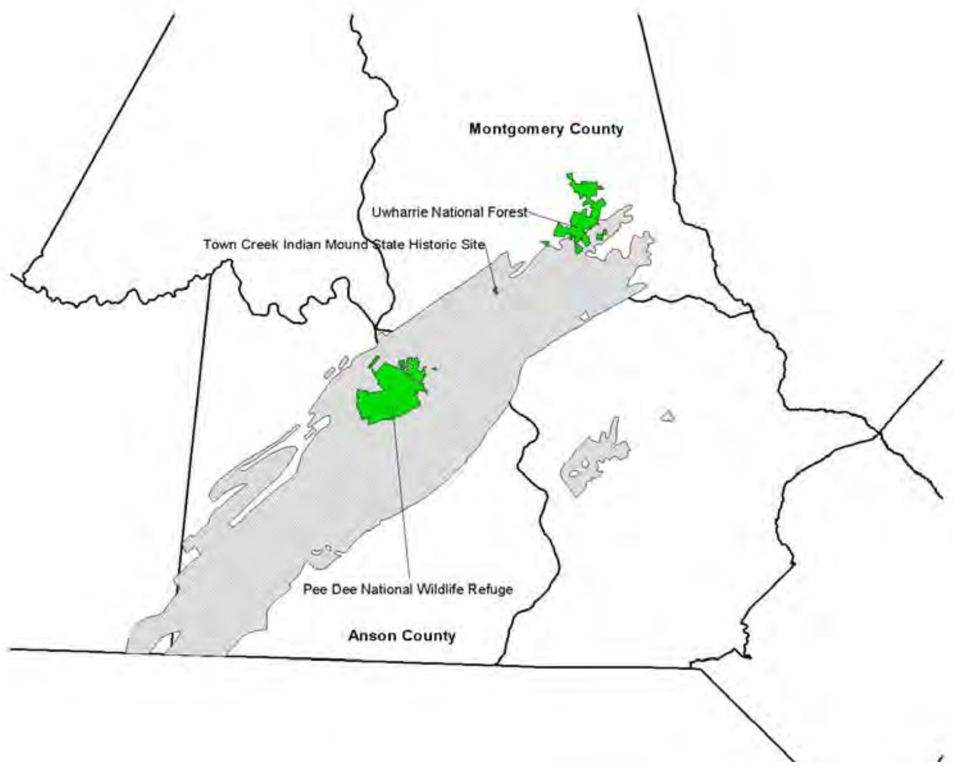


Figure 4-5. Publicly Owned Lands in the Southern Portion of the Deep River Basin



Important natural areas of North Carolina's Triassic Basins

The North Carolina Natural Heritage Program inventories, catalogues and supports conservation of the rarest and most outstanding elements of the natural diversity of North Carolina. These include rare plants and animals and significant natural areas. Information collected by the Natural Heritage Program allows government agencies and private developers to make better decisions about project siting and design. This information also helps public and private agencies set priorities for acquisition of conservation lands.

Significant Natural Heritage Areas

A Significant Natural Heritage Area (SNHA) is an area of land or water identified by the Natural Heritage Program as being important for conservation of the state's biodiversity. SNHAs contain one or more natural heritage elements: high-quality or rare natural communities, rare plant or animal species and special animal habitats. Designation as an SNHA does not provide legal protection or prevent natural gas exploration and production from occurring within these sites.

SNHAs are rated based on the value of the natural heritage elements found there; significance is rated based on the rarity and quality of those elements in comparison with other sites. SNHAs are designated as significant at the national, regional, state or county level using parameters developed by the Natural Heritage Program, NatureServe and The Nature Conservancy to measure statewide and global rarity for rare species and communities. These definitions are shown in Table 4-5.

Table 4-5. Definitions for SNHA Significance Rankings

Rank	Natural Area Significance
A	**Nationally** significant natural areas contain examples of natural communities, rare plant or animal populations, or geologic features that are among the highest quality, most viable, or best of their kind in the nation, or clusters of such elements that are among the best in the nation.
B	**Statewide** significant natural areas contain similar ecological resources that are among the best occurrences in North Carolina. There are a few better quality representatives or larger populations on nationally significant sites elsewhere in the nation or possibly within the state.
C	**Regionally** significant natural areas contain natural elements that may be represented elsewhere in the state by better quality examples, but which are among the outstanding examples in their geographic region of the state. A few better examples may occur in nationally or state significant natural areas. Regions consist of an area the size of about five counties.
D	**County** significant natural areas contain exemplary instances of high quality community types that are either common or at least fairly widespread in this region, or sites that serve as important wildlife habitat. These sites are considered important for local conservation based on size and integrity of the site, maturity and diversity of the community, and lack of disturbance/fragmentation. Sites important for wildlife habitat are also connected by corridors of continuous forest habitat, and are thus part of a network of wildlife habitats extending through the landscape.

Of the 129 SNHAs identified within the Triassic Basins, 12 are of national significance based on the importance of the area for rare species and high quality aquatic habitat. Thirty-five SNHAs have state significance; an additional 35 have regional significance and 47 are significant at the county level. SNHAs that are partially or wholly within the Triassic Basins are shown by rank in the following tables.

Table 4-6. Nationally Significant Natural Heritage Areas within the Triassic Basins (Rank A)

Site Name	Acreage	Ownership
Beaver Pond Road Longleaf Pine Forest	83.37	Federal
Catsburg Natural Area	110.15	Federal, Private
Dan River Aquatic Habitat	1,240.27	Public Waters
Eno River Diabase Sill	44.49	State
Knap of Reeds Creek Diabase Forest and Glades	162.56	Federal, State
Knap of Reeds Creek Diabase Levee and Slopes	136.09	Federal, State
Lower Brown Creek Swamp	2,023.00	Federal, Private
Lower Rocky River/Lower Deep River Aquatic Habitat	396.72	Public Waters
Mayo River Aquatic Habitat	207.06	Public Waters
Middle Deep River Aquatic Habitat	1,451.25	Public Waters
Picture Creek Diabase Barrens	407.35	State, Private
Upper Tar River Aquatic Habitat	257.87	Public Waters

Table 4-7. Statewide Significant Natural Heritage Areas within the Triassic Basin (Rank B)

Site Name	Acreage	Ownership
Beaverdam Lake Swamps and Arkose Outcrops	899.17	Federal, Private
Bennett Bridge Diabase Dike	4.05	Federal
Big Oak Woods	56.57	State
Cedar Mountain	141.29	Private
Cheek Creek Ridge	34.01	Federal
Diabase Sill Near Clay	540.03	Private
Drowning Creek Aquatic Habitat	180.05	Public Waters
Endor Iron Furnace Natural Area	253.61	State
Fitzgerald Woodland	88.36	Private
Flat River Bend Forest	17.41	Federal
Grassy Islands/Smith Lake	2,242.43	Private
Griffen Hunt Preserve	6.53	State, Private
Gulf Diabase Forest	6.83	Private
Haw River Dicentra Slopes	15.94	Private
Hebron Road Remnant Glade	90.11	State, Private
Jacobs Creek Slopes	14.51	Private
Jordan Lake Bald Eagle Habitat	5,995.28	Federal, State
Lake Rogers Diabase Area	13.13	State, Private
Lick Creek Bottomland Forest	1,743.79	Federal
Lower Little River (Montgomery) Aquatic Habitat	116.36	Public Waters
Lower Little River (Richmond) Corridor	1,703.65	Private
Lower New Hope Creek Floodplain Forest and Slopes	1,422.76	Federal, Private
Mason Farm/Laurel Hill Oak-Hickory Forest	447.43	State
Mayodan Bluffs	47.99	Private
Morgan Creek Bluffs	189.20	State, Private
Morgan Creek Floodplain Forest	1,537.86	Federal, Private
Mountain Creek Corridor	1,804.97	Private
Naked Creek Aquatic Habitat	62.89	Public Waters
New Hope Creek Aquatic Habitat	32.86	Public Waters
New Hope Creek Bottomland Forest	964.59	Federal
Northside Diabase Area	1.90	Federal
Redwood Road Remnant Glade	22.48	Federal
South Butner Diabase Swamp	99.19	State
Upper Brown Creek Swamp	3,036.51	Private
William B. Umstead State Park	5,578.80	State

Table 4-8. Regionally Significant Natural Heritage Areas within the Triassic Basin (Rank C)

Site Name	Acreage	Ownership
Bear Slide Bluff	12.01	State
Big Beaver Island Creek Slopes	26.09	Private
Cabin Branch Creek Bottomland-Swamp	196.47	Federal
Cape Fear River/McKay Island Floodplain	154.71	Private
Carbonton Diabase Sill	104.48	Private
Deep River Slopes Near Carbonton	44.69	Private
Deep River/Patterson Creek Slopes	74.10	Private
Dry Creek/Mount Moriah Bottomland	438.97	Private
Duke Forest Oak-Hickory Upland	423.32	Private
Gum Springs Church Road Slopes	285.09	Federal
Indian Creek Diabase Slope	16.45	Private
Jenkins Road Diabase Dike	41.33	Federal, Private
Lagrange Diabase Bog	46.52	Private
Leaksville Loam Forests	138.29	Private
Little River Shooting-Star Slopes	109.55	Private
Lower Deep River Slopes	602.20	State, Private
McLendons Creek Diabase Sill and Levees	110.26	Private
Middle Eno River Bluffs and Slopes	2,123.81	State, Local
Middle Pee Dee River Aquatic Habitat	1,459.88	Public Waters
Moncure Boggy Streamheads	269.07	Federal, Private
Northeast Creek Floodplain Forest	819.93	Federal, Private
Northeast Creek/Panther Creek Dikes and Bottomlands	498.66	Federal
Pleasantville Basic Forest	137.01	Private
Polly Branch Slopes	156.64	Federal
Rocky Branch Conglomerate Exposure	60.13	Federal
Rocky Ford Creek Mountain Laurel Bluff	43.29	State
Roundhouse Road Forest	74.63	Private
Savannah Church Diabase Dike	41.19	Private
Smith River Bluffs	20.96	Private
Tar River/Triassic Basin Floodplain	488.99	Private
Thoroughfare Creek Wetlands	201.69	Federal
Upper Drowning Creek Swamp Forest	4,213.34	State, Private
Utley Creek Slopes	459.20	Private
White Oak Creek Floodplain	613.78	Federal
Woodwards Branch Diabase Dike	34.38	Private

Table 4-9. County Significant Natural Heritage Areas within the Triassic Basin (Rank D)

Site Name	Acreage	Ownership
Ash Camp Creek Wetland	53.28	Private
Battle Park	80.77	State
Beaver Creek Floodplain	172.08	Federal, Local
Big Buffalo Creek Galax Slope	20.05	Private
Big Woods Road Upland Forests	1,964.25	Federal, Private
Bush Creek Marshes	216.52	Federal, Private
Candor Lake Slopes and Wetland	28.96	Private
Center Church Headwaters of Little Governors Creek	29.45	Private
Cheek Creek Slope	26.37	Private
Collins Bridge Bluffs	48.60	Private
Cub Creek Bottomlands and Beaver Ponds	103.31	Private
Deep River Bend	22.79	Private
Deep River/Little Governors Creek Forests	91.35	Private
Drowning Creek Slopes	94.29	Private
Dry Fork Pocket Creek Forest	20.81	Private
Falls Lake Shoreline and Tributaries	7,748.07	Private
Gate 4 Mafic Forests	241.28	Private
Harrisville Basic Forest	35.49	Private
Hollemans Crossroads Salamander Pools	3.36	Private
Hollemans Crossroads Slopes	132.37	Private
Jim Branch/Buckhorn Creek Forests	14.56	Private
Kit Creek Slopes and Floodplain	55.36	Federal
Knap of Reeds Creek Beaver Ponds and Swamp	66.69	Federal
Leatherwood Cove	159.02	Private
Little Beaverdam Creek Slopes	95.80	Federal, Private
Little Creek Bottomlands and Slopes	1,447.28	Federal, State, Private
Little Indian Creek Galax Bluff	103.26	Private
Little River (Durham) Corridor	1,185.91	Local, Private
Lower Eno River/Little River Bottomlands	2,157.02	Federal, Private
Middle Lick Creek Bottomlands	1,034.18	Federal, Private
Mills Creek Equisetum Wetland	14.19	Private
New Hope Overlook Bluff and Slopes	405.81	Federal
North Edwards Ridge	119.75	Private
Old Weaver Trail Slopes	317.89	Federal
Parkers Creek Ridges	226.88	Federal
Pee Dee River Skunk Cabbage Seep	145.18	Federal
Pine Hall Slopes	130.37	Private
Poes Ridge/Dam Road Upland Forests	177.61	Federal
Shaddox Creek Swamp	22.62	Private
Shearon Harris Longleaf Pine Forest	356.91	Private
Smith Creek Alluvial Forest and Slopes	479.76	Federal, Private
Stirrup Iron Creek Marsh and Sloughs	217.87	Private
Third Fork Creek Wetlands	144.70	Federal, Private
Town Creek Indian Mound Bottomland	61.22	Private
Town Fork Forest	255.16	Private
Weaver Creek Pine Forest	581.87	Federal
Wide Mouth Creek Conglomerate Exposure	24.10	Private

Significant Natural Heritage Areas within the Triassic Basin are shown in the following maps.

Figure 4-6. SNHAs in the Dan River Triassic Basin

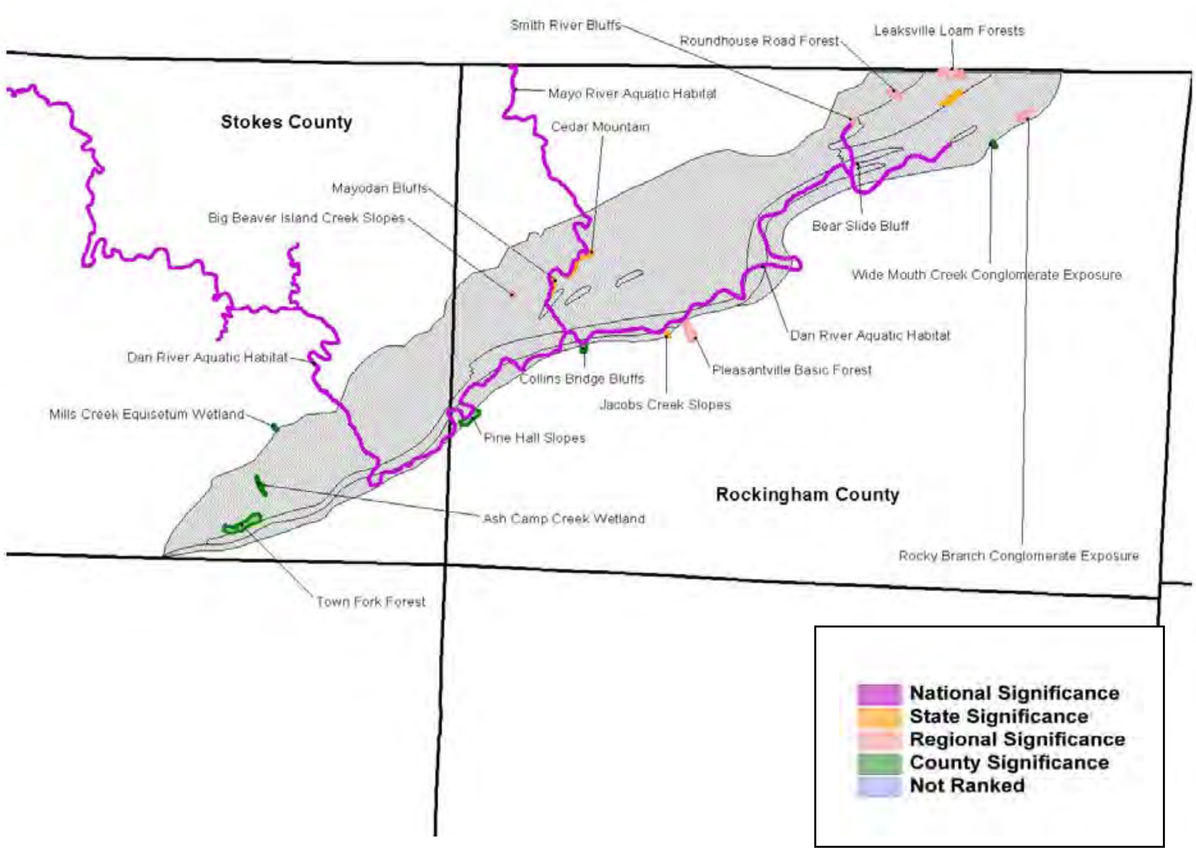


Figure 4-7. SNHAs in the Northern Portion of the Deep River Basin

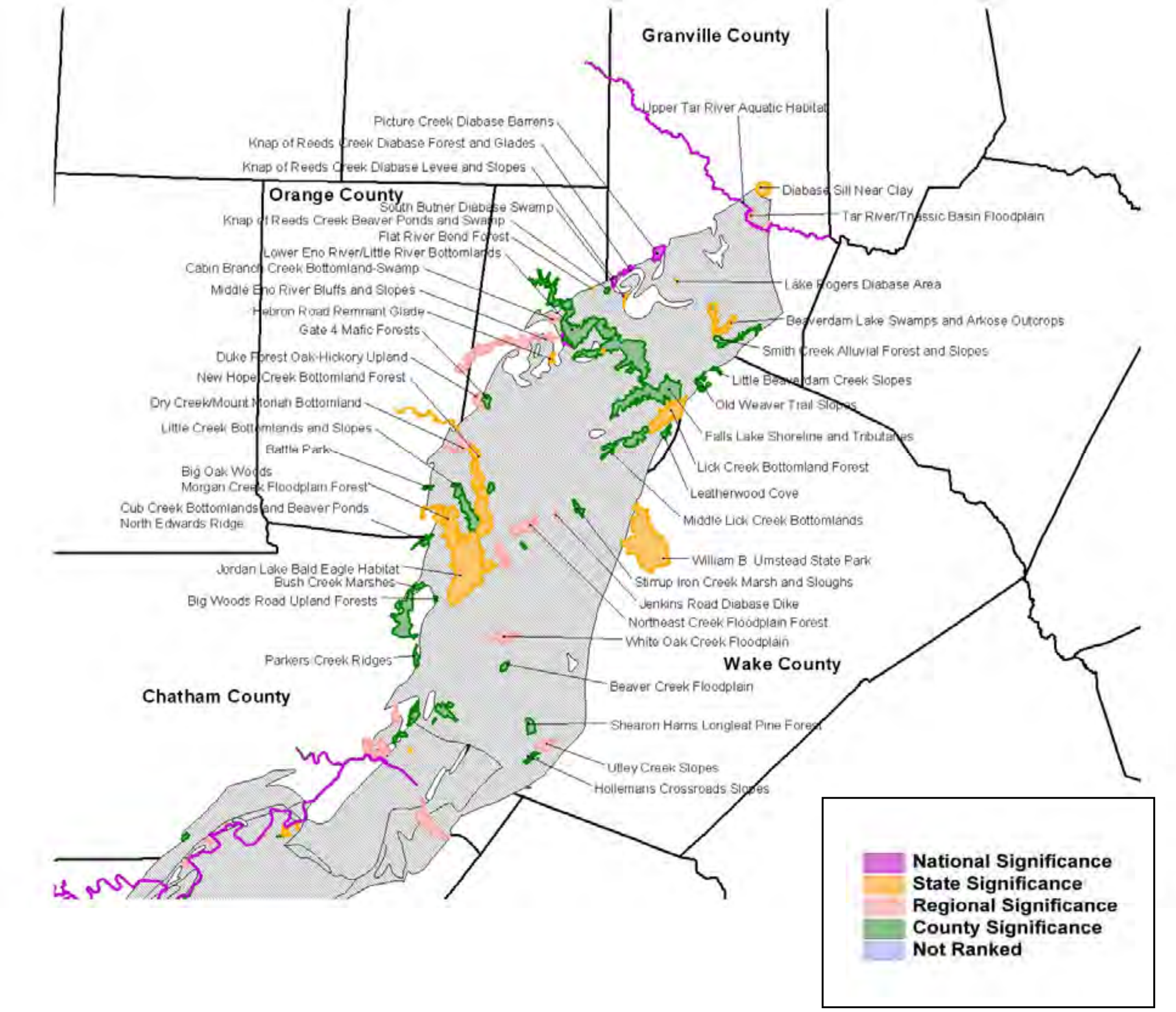


Figure 4-8. SNHAs in the Southern Portion of the Deep River Basin

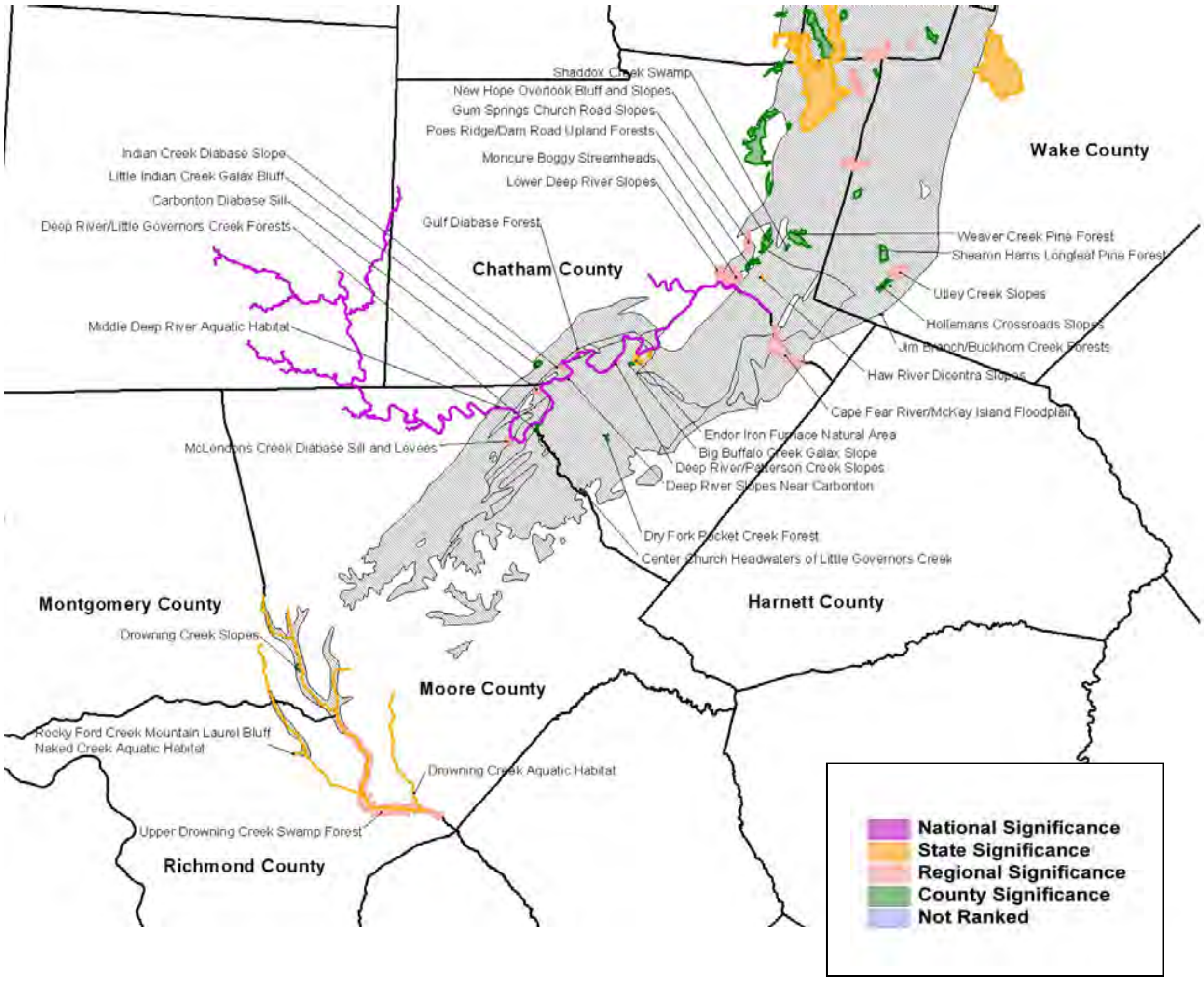
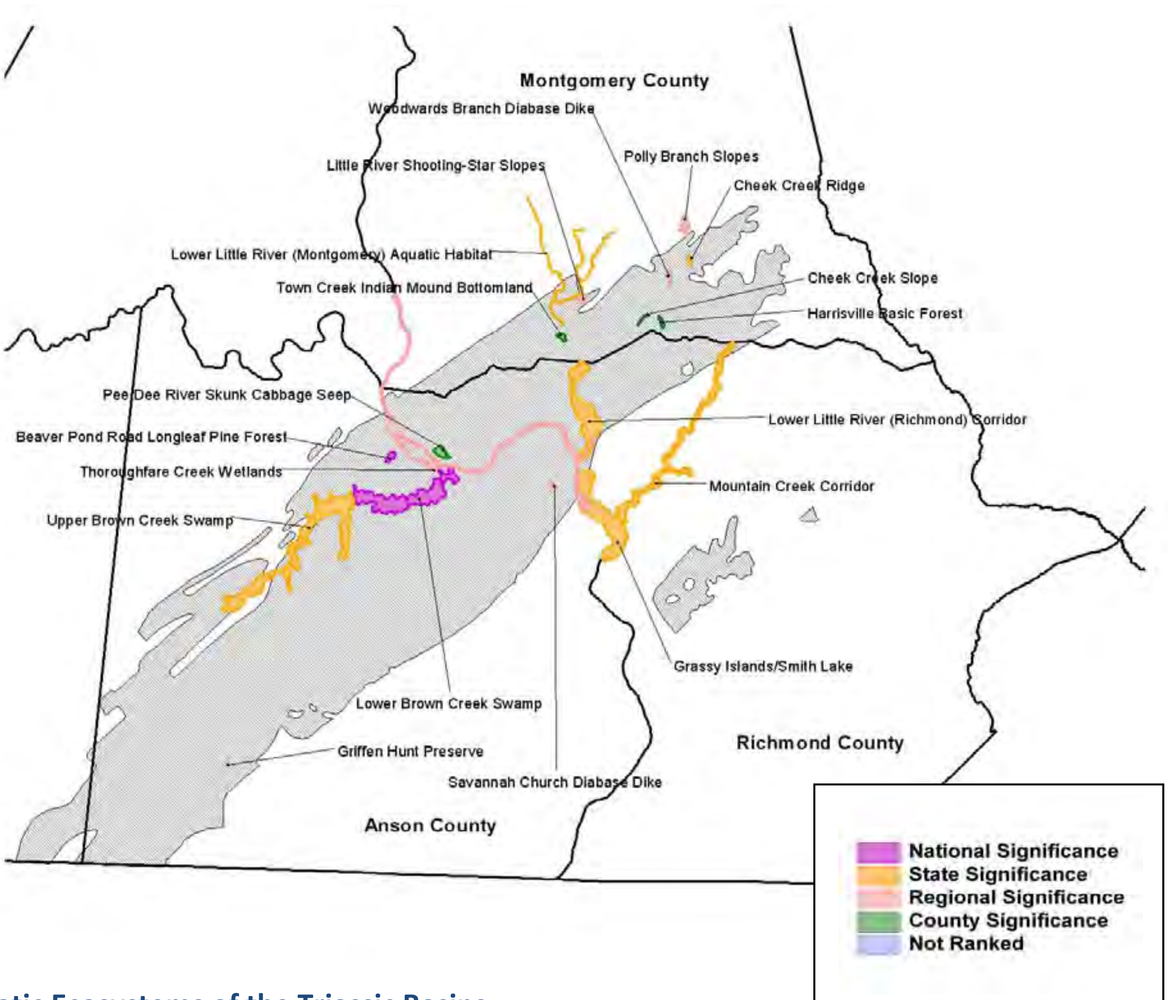


Figure 4-9. SNHAs in the Wadesboro Sub-basin



Aquatic Ecosystems of the Triassic Basins

Aquatic ecosystems perform many important functions, including recycling nutrients, purifying water, reducing flood damage, recharging groundwater and providing wildlife habitat.[216] Streams, rivers and riparian ecosystems in central North Carolina, including the area underlain by the Triassic Basins, also support many rare aquatic species. Native aquatic species are able to survive and reproduce within a certain range of environmental variation of the habitat, such as water depth, flow velocity, water temperature, and oxygen content.[217] Aquatic species are important indicators of a stream's health because of their specific habitat requirements.

Freshwater mussels are a particularly important group of aquatic species. These mollusks filter sediment and pollutants, thereby improving water quality. Mussels are important indicators of stream health and a food source for many species of fish, reptiles, birds and mammals. A mussel's shell may be covered by aquatic insects, algae and plants and the empty shell of a

[216] Ibid, p. 47.
[217] NYSDEC, p. 6-3 - 6-4.

dead mussel can serve as a nesting site for small fish.[218] The United States has a greater variety of freshwater mussels than anywhere else in the world. North Carolina has about 60 mussel species; 80 percent of those species are considered rare and in need of protection.[219] Freshwater mussels face threats from non-point source pollution, sedimentation, habitat loss through channelization, clearing of riparian vegetation, dredging and dam construction.[220]

The aquatic habitats of the Deep River Basin and the Dan River Basin are well known as ecologically important systems.[221] The Deep River, an Atlantic Slope river that eventually drains to the Atlantic Ocean, joins the Haw River to form the Cape Fear River. The Dan River flows north into Virginia where it joins the Roanoke River in Kerr Reservoir. Both the Dan River and Deep River hydrologic basins and their tributaries support a high diversity of aquatic organisms, including largemouth bass *(Micropterus salmoides)*, sunfishes, catfishes, minnows, darters, suckers, mussels, crayfish and other invertebrates.

A number of rare species are found in the Triassic Basin portion of the Deep River watershed. The Cape Fear shiner, a minnow found only in aquatic habitats in the vicinity of the fall line in Chatham, Lee, Harnett, Moore and Randolph counties, is a federally listed endangered species. The Deep River also contains habitat for several rare freshwater mussels, including Atlantic pigtoe (*Fusconaia masoni*), yellow lampmussel (*Lampsilis cariosa*), Savannah lilliput (*Toxolasma pullus*), triangle floater (*Alasmidonta undulata*), Roanoke slabshell (*Elliptio roanokensis*), creeper (*Strophitus undulatas*), notched rainbow (*Villosa constricta*), and eastern creekshell (*V. delumbis*); fish such as the Carolina redhorse (*Moxostoma sp. 'Carolina'*) and Roanoke bass (*Ambloplites cavifrons*); the federally endangered plant Harperella (*Ptilimnium nodosum*); and the Septima's clubtail dragonfly (*Gomphus septima*).

The Dan River aquatic habitat is considered by the Natural Heritage Program to be a nationally significant natural heritage area, and the NCWRC has identified this river as a high priority area for long-term conservation. In addition, this basin is presently the focus of efforts by North Carolina and Virginia state agencies and federal agencies to restore diadromous fishery resources such as blueback herring (*Alosa aestivalis*), alewife (*A. pseudoharengus*), American shad (*A. sapidissima*), American eel (*Anguilla rostrata*), and striped bass (*Morone saxatilis*), with an initial focus on American shad. There are records for the existence of the federal and state endangered James spinymussel (*Pleurobema collina*), the federal species of concern and state endangered green floater (*Lasmigona subviridis*), state species of special concern riverweed darter (*Etheostoma podostemone*), bigeye jumprock (*Scartomyzon ariommus*), and notched rainbow (*Villosa constricta*), and the state significantly rare Roanoke hogsucker (*Hypentelium roanokense*) in the Dan River system. Portions of the Dan River have been formally designated

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[218] Virginia Department of Game and Inland Fisheries. "Freshwater Mussels." Retrieved February 6, 2012 from http://www.dgif.virginia.gov/wildlife/freshwater-mussels.asp.

[219] Chatham Conservation Partnership. A Comprehensive Conservation Plan for Chatham County.

[220] U.S. Fish & Wildlife Service. "Discover Freshwater Mussels: America's Hidden Treasure." Retrieved February 24, 2012 from http://www.fws.gov/news/mussels.html.

[221] Schwab, Edward C. *A Preliminary Inventory of the Natural Areas of Lee County, North Carolina.* Compiled and edited by Laura Cotterman. NC Natural Heritage Program, NC Department of Environment and Natural Resources. Raleigh, NC, 1996.

as a State Water Trail by the N.C. Division of Parks and Recreation; and the remaining river segments comprise an informal water trail.

Terrestrial ecosystems of the Triassic Basins

Some terrestrial species in the Triassic Basins depend on unfragmented upland and bottomland hardwood forests; others require early successional habitats, floodplain forests, riverine aquatic communities or wetland habitats. Many terrestrial species depend on a combination of these habitats. Area-sensitive species require large, unfragmented habitats as home ranges and to support biological dispersal. Large, unfragmented hardwood forests with intact understories provide forage (such as acorns and nuts) and nesting sites.[222]

Many species use floodplain forests as travel corridors, and fragmentation of these areas can impact these species by altering dispersal and migration patterns. Reptiles and amphibians are especially vulnerable to these impacts. In addition, floodplain forests contain floodplain pools, that serve as breeding sites for amphibians.[223]

Natural Communities

The Triassic Basins have high quality natural communities. Natural communities are distinct and reoccurring assemblages of populations of plants, animals, bacteria and fungi that are naturally associated with each other and the physical environment. These natural communities play an important role in maintaining natural diversity. By protecting examples of all natural community types, the majority of species can be protected without laborious individual attention. Natural communities also have intrinsic natural and aesthetic values, and may contain valuable scientific resources.[224]

The types of natural communities found in the Triassic Basin are shown in Table 4-10 below. Natural communities located in the Deep River basin include high quality examples of floodplain pools, Piedmont/low mountain alluvial forest, basic mesic forest and Piedmont longleaf pine forest. Care in siting drilling pads and infrastructure can limit direct impacts to high quality natural communities and rare plants. However, care must be taken to avoid the indirect effects of air pollution, water pollution and other impacts that can travel.

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[222] Chatham Conservation Partnership. *A Comprehensive Conservation Plan for Chatham County*.
[223] Chatham Conservation Partnership.
[224] Schwab, Edward C. 1996. A Preliminary Inventory of the Natural Areas of Lee County, North Carolina. Compiled and edited by Laura Cotterman. NC Natural Heritage Program, NC Department of Environment and Natural Resources, Raleigh, NC.

Table 4-10. Natural Communities within the Triassic Basin

Natural Community
Diabase glade
Piedmont calcareous cliff
Xeric Hardpan Forest (Northern Prairie Barren Subtype)
Piedmont longleaf pine forest
Piedmont mafic cliff
Hillside seepage bog
Piedmont/mountain swamp forest
Dry Basic Oak--Hickory Forest
Xeric Hardpan Forest (Basic Hardpan Subtype)
Granitic flatrock
Upland depression swamp forest
Floodplain pool
Dry-Mesic Basic Oak--Hickory Forest (Piedmont Subtype)
Xeric hardpan forest
Basic Oak--Hickory Forest
Piedmont Alluvial Forest
Streamhead pocosin
Low elevation seep
Piedmont/coastal plain heath bluff
Coastal plain small stream swamp (blackwater subtype)
Dry oak--hickory forest
Dry-mesic oak--hickory forest
Oxbow lake
Piedmont/low mountain alluvial forest
Piedmont/mountain bottomland forest
Piedmont/mountain levee forest
Piedmont/mountain semipermanent impoundment
Basic mesic forest (piedmont subtype)
Mesic mixed hardwood forest (piedmont subtype)
Piedmont Boggy Streamhead

Rare species of the Triassic Basins

As part of its mission to preserve the biological diversity of North Carolina, the North Carolina Natural Heritage Program documents the status and distribution of the rarest plants and animals by working closely with experts from across the state and in cooperation with the U.S. Fish and Wildlife Service, the Plant Conservation Program of the N.C. Department of Agriculture and Consumer Services and the Wildlife Diversity Program of the N.C. Wildlife Resources

Commission. The Natural Heritage Program takes the lead role in North Carolina in the inventory of the state's natural diversity and the identification of important natural areas and rare species habitats.

Threatened and endangered species of the Triassic Basins

The North Carolina Natural Heritage Program maintains lists of species native to North Carolina that are officially recognized by federal or state agencies as protected or otherwise rare in North Carolina. These species are shown in Table 4-11 and Table 4-12 and are described in greater detail on the following pages.

Table 4-11. Federally or State-Listed Endangered or Threatened Plant Species

Taxa Group	**Federal Status**	**State Status**
Vascular Plant		
American Bluehearts, *Buchnera americana*		**E**
Big Shellbark Hickory, *Carya laciniosa*		**T**
Buffalo Clover, *Trifolium reflexum*		**T**
Carolina Thistle, *Cirsium carolinianum*		**E**
Chapman's Redtop, *Tridens chapmanii*		**T**
Douglass's Bittercress, *Cardamine douglassii*		**T**
Eaton's Ladies'-tresses, *Spiranthes eatonii*		**E**
Georgia Indigo-bush, *Amorpha georgiana*		**E**
Glade Bluecurls, *Trichostema brachiatum*		**E**
Harperella, *Ptilimnium nodosum*	**E**	**E**
Hoary Puccoon, *Lithospermum canescens*		**T**
Indian Physic , *Gillenia stipulata*		**T**
Jacob's Ladder, *Polemonium reptans var. reptans*		**T**
Low Wild-petunia, *Ruellia humilis*		**E**
Michaux's Sumac, *Rhus michauxii*	**E**	**E**
Narrow-leaf Aster, *Symphyotrichum laeve var. concinnum*		**T**
Pink Thoroughwort, *Fleischmannia incarnata*		**T**
Pondberry, *Lindera melissifolia*	**E**	**E**
Prairie Blue Wild Indigo, *Baptisia australis var. aberrans*		**E**
Rough-leaf Loosestrife, *Lysimachia asperulifolia*	**E**	**E**
Schweinitz's Sunflower, *Helianthus schweinitzii*	**E**	**E**
Serpentine Aster, *Symphyotrichum depauperatum*		**E**
Shale-barren Skullcap, *Scutellaria leonardii*		**E**
Shooting-star, *Primula meadia*		**T**
Smooth Coneflower, *Echinacea laevigata*	**E**	**E**
Southern Anemone, *Anemone berlandieri*		**E**
Southern Skullcap, *Scutellaria australis*		**E**
Tall Larkspur, *Delphinium exaltatum*		**E**
Thick-pod White Wild Indigo, *Baptisia alba*		**T**
Veined Skullcap, *Scutellaria nervosa*		**E**
Virginia Spiderwort, *Tradescantia virginiana*		**T**
Wiry Panic Grass, *Panicum flexile*		**T**

Table 4-12. Federally or State-Listed Endangered or Threatened Animal Species

Taxa Group	Federal Status	State Status
Invertebrate Animal		
Atlantic Pigtoe, *Fusconaia masoni*		E
Brook Floater, *Alasmidonta varicosa*		E
Carolina Creekshell, *Villosa vaughaniana*		E
Creeper , *Strophitus undulatus*		T
Dwarf Wedgemussel, *Alasmidonta heterodon*	E	E
Eastern Lampmussel, *Lampsilis radiata*		T
Eastern Pondmussel, *Ligumia nasuta*		T
Green Floater, *Lasmigona subviridis*		E
James Spinymussel, *Pleurobema collina*	E	E
Roanoke Slabshell , *Elliptio roanokensis*		T
Savannah Lilliput , *Toxolasma pullus*		E
Triangle Floater, *Alasmidonta undulata*		T
Yellow Lampmussel , *Lampsilis cariosa*		E
Yellow Lance, *Elliptio lanceolata*		E
Vertebrate Animal		
Bald Eagle, *Haliaeetus leucocephalus*		T
Bigeye Jumprock, *Moxostoma ariommum*		T
Cape Fear Shiner, *Notropis mekistocholas*	E	E
Carolina Madtom, *Noturus furiosus*		T
Carolina Redhorse, *Moxostoma sp. 3*		T
Red-cockaded Woodpecker, *Picoides borealis*	E	E
Roanoke Logperch, *Percina rex*	E	E

Federal Status

Federally listed endangered and threatened species are protected under the provisions of the Endangered Species Act of 1973 (ESA), as amended. The U.S. Fish and Wildlife Service has authority under the Act to designate a species as threatened or endangered. The ESA defines an endangered species as "in danger of extinction throughout all or a significant portion of its range." A threatened species is "likely to become an endangered species within the foreseeable future throughout all or a significant portion of its range."[225] The area underlain by the Triassic Basin includes terrestrial and aquatic habitat for 11 species listed as endangered federally, and no species that are listed as threatened federally. These species, and the habitats needed to support them, are described in greater detail below.

[225] North Carolina Natural Heritage Program. *Guide to Federally Listed Endangered and Threatened Species of North Carolina.* 2001. Web. February 13, 2012. http://www.ncnhp.org/Images/Federal%20E&T%20NC-5.pdf.

Several additional species currently identified as endangered, threatened, special concern and significantly rare in North Carolina have been included in a petition for listing at the federal level as endangered or threatened. These include the Neuse River waterdog (*Necturus lewisi*), the brook floater (*Alasmidonta varicosa*), the yellow lance (*Elliptio lanceolata*), Atlantic pigtoe (*Fusconaia masoni*), green floater (*Lasmigona subviridis*), Carolina madtom (*Noturus furiosus*), Septima's clubtail (*Gomphus septima*), the ravine sedge (*Carex impressinervia*), and bog spicebush (*Lindera subcoriacea*).

Cape Fear shiner (*Notropis mekistocholas*) – The Cape Fear shiner is a small minnow that is native to the upper Cape Fear River Basin. It is known from tributaries and mainstreams of the Deep, Haw and Rocky rivers in Chatham, Harnett, Lee, Moore and Randolph counties. Only five populations of the shiner are thought to exist. It prefers gravel, cobble and boulder substrates, and has been seen in slow pools, riffles and slow runs. Dams and loss of riverine habitat to water impoundments, as well as deteriorating water quality, have had serious impacts on the shiner by inundating its rocky riverine habitat. Changes in stream flow, increased stormwater runoff, road construction, wastewater discharge and other forms of development have threatened the species.[226]

Dwarf Wedgemussel (*Alasmidonta heterodon*) – All river mussels live partly buried in the substratum, where they filter feed on planktonic algae, bacteria, protozoa, rotifers, fine particles of decaying leaves and other suspended organic matter. Due to their limited mobility and filter-feeding habits, river mussels are generally sensitive to stream channel erosion and siltation, high turbidity (other than food particles), severe droughts, excessive heat, low dissolved oxygen, ammonia, metals, herbicides, pesticides, blooms of blue-green algae or other algae that may be toxic, and urban development impacts.[227]

A century ago the dwarf wedgemussel lived in 15 watersheds along the Atlantic Coast from New Brunswick, Canada to North Carolina. Today, this mussel has been eliminated in Canada and is found in only nine watersheds in the United States.[228] It is found in portions of the Durham Sub-basin of the Deep River Basin. It inhabits creeks and rivers with a slow to moderate current and a sand, gravel or muddy bottom. The species is threatened by toxic effects from domestic, industrial and agricultural pollution.[229]

James Spinymussel (*Pleurobema collina*) – The James spinymussel has declined rapidly during the past two decades. In North Carolina, it is found in portions of the Dan River Basin. It prefers free-flowing streams with a variety of flow regimes. Threats to the species include "impoundment of waterways, water pollution, stream channelization, sewage discharge,

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[226] U.S. Fish & Wildlife Service. "Cape Fear Shiner (Notropis mekistocholas)." *North Carolina Ecological Services*. Web. Accessed February 13, 2012. http://www.fws.gov/nc-es/fish/cfshiner.html

[227] Chatham County Conservation Plan Appendix A., p. 8.

[228] Fisheries and Oceans Canada. "Aquatic Species at Risk – Dwarf Wedgemussel." Retrieved March 12, 2012 from http://www.dfo-mpo.gc.ca/species-especes/species-especes/dwarf_wedgemussel-alasmidonte-eng.htm.

[229] U.S. Fish & Wildlife Service. "Dwarf Wedge Mussel in North Carolina." Retrieved February 13, 2012. http://www.fws.gov/nc-es/mussel/dwmussel.html.

agricultural runoff including pesticides and fertilizers, poor logging and road/bridge construction practices, and discharge of chlorine."[230]

Harperella (*Ptilimnium nodosum*) – This annual herb has small, white flowers that grow in heads, similar to Queen Anne's lace. Harperella is known from 12 populations, two of which occur in North Carolina (one in Granville and one in Chatham counties). Harperella grows in rocky or gravel shoals and the margins of clear, swift-flowing streams as well as on the edges of intermittent pineland ponds in the coastal plain.[231]

Michaux's sumac (*Rhus michauxii*) – Michaux's sumac is a dense shrub that grows from one to three feet tall. The plant grows in sandy or rocky open woods and survives best in open areas, such as highway rights-of-way, roadsides or the edges of clearings. However, it has a low reproductive capacity, and it is threatened by habitat destruction due to residential and industrial development. Two historic populations were destroyed by development.[232]

Pondberry (*Lindera melissifolia*) – The pondberry, or Southern spicebush, is a deciduous shrub that grows up to six feet tall. It bears pale yellow flowers in the spring and red, oval fruits in the fall. It grows in seasonally flooded wetlands such as floodplains, bottomland hardwood forests or forested swales and along the margins of ponds and depressions in pinelands.[233] The pondberry is threatened by drainage ditching and land development.[234]

Red-cockaded woodpecker (*Picoides borealis*) – The red-cockaded woodpecker is a territorial, nonmigratory species native to the American southeast. They require large areas of mature pine-dominated forest with a relatively open understory.[235] Red-cockaded woodpeckers seek out living pines with red heart disease in which to excavate nesting holes. The specificity of the bird's breeding habitat makes it extremely vulnerable to habitat loss. Today, most pine trees are cut before they reach an age at which red heart disease is common.[236]

Roanoke logperch (*Percina rex*) – This small fish presently occurs in five populations. The Roanoke logperch typically inhabits medium to large, warm, clear streams and small rivers. In North Carolina it is found in the Dan River Sub-basin of the Deep River Triassic Basin. The logperch suffered massive habitat loss following the construction of water impoundments in the Roanoke River Basin in the 1950s and 1960s, which disrupted the species' ability to move throughout its historic range. Current threats to the logperch are stormwater runoff and "spills

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[230] U.S. Fish & Wildlife Service Virginia Field Office. "James Spinymussel." Retrieved February 13, 2012. http://www.fws.gov/northeast/virginiafield/pdf/endspecies/fact_sheets/james%20spiny.pdf
[231] U.S. Fish & Wildlife Service. "Harperella in North Carolina." *North Carolina Ecological Services*. Retrieved February 13, 2012. http://www.fws.gov/nc-es/plant/harperella.html
[232] U.S. Fish & Wildlife Service. "Michaux's Sumac in North Carolina." *North Carolina Ecological Services*. Retrieved February 13, 2012. http://www.fws.gov/nc-es/plant/michsumac.html
[233] NatureServe Explorer. "*Lindera melissifolia*." Retrieved March 12, 2012 from http://www.natureserve.org/explorer/servlet/NatureServe?searchName=Lindera+melissifolia.
[234] U.S. Fish & Wildlife Service. "Pondberry (Southern Spicebush) in North Carolina." *North Carolina Ecological Services*. Retrieved February 13, 2012. http://www.fws.gov/nc-es/plant/pondberry.html
[235] Chatham County Conservation Plan Appendix A, p. 3.
[236] The Nature Conservancy. "Red-cockaded Woodpecker." *Animal Species Profiles*. Retrieved February 13, 2012. http://www.nature.org/newsfeatures/specialfeatures/animals/birds/red-cockaded-woodpecker.xml

and accidents associated with chemical releases and destruction and degradation of habitat."[237] Water withdrawals in the Roanoke River basin also threaten this species.[238]

Rough-leaf loosestrife (*Lysimachia asperulifolia*) – Rough-leaf loosestrife is a perennial herb with yellow flowers that blooms from mid-May to June. It is endemic to the coastal plain and sandhills of North Carolina and South Carolina, and occurs on the edges between longleaf pine uplands and pond pine pocosins. Fire suppression, wetland drainage and residential and commercial development pose significant threats to the continued existence of this species.[239]

Schweinitz's sunflower (*Helianthus schweinitzii*) – This perennial herb with yellow flowers is believed to have once occupied prairie-like habitats that were maintained by fire. Today this sunflower lives on roadsides, power line clearings, pastures, woodland openings and other sunny or semi-sunny areas. Schweinitz's sunflower is threatened by fire suppression, highway construction, residential and commercial development, and maintenance activities in roadsides and utility corridors.[240]

Smooth coneflower (*Echinacea laevigata*) – The smooth coneflower is a perennial herb in the Aster family with light pink or purple drooping flowers. It is typically found in sunny places such as open woods, cedar barrens, roadsides, dry limestone bluffs and utility corridors. Historically the smooth coneflower existed in Pennsylvania, Maryland, Virginia, North Carolina, South Carolina, Georgia, Alabama and Arkansas, but today is found only in Virginia, North Carolina, South Carolina and Georgia. In North Carolina, it is found in Durham, Granville, Mecklenburg and Rockingham counties. It is threatened by fire suppression and habitat destruction resulting from highway construction, residential and commercial development, and maintenance activities in roadsides and utility corridors.[241]

State status and state regulations related to endangered, threatened and special concern species

Plants and animals have different state status definitions and are assigned status by different agencies. The Plant Conservation Program (part of the N.C. Department of Agriculture and Consumer Services) determines plant statuses. The North Carolina Wildlife Resources Commission and the Natural Heritage Program determine animal statuses.

State listed plants

Endangered, threatened and special concern species of plants have limited protection status under the Plant Protection and Conservation Act of 1979 (G.S. 106, Article 19A). The Plant Protection and Conservation Act and the North Carolina Endangered Species Act (G.S. 113,

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[237] U.S. Fish & Wildlife Service Virginia Field Office. "Roanoke logperch." Retrieved February 13, 2012. http://www.fws.gov/northeast/virginiafield/pdf/endspecies/fact_sheets/roanoke%20logperch.pdf
[238] Ibid.
[239] U.S. Fish & Wildlife Service. "Rough-leaf Loosestrife (Lysimachia asperulifolia)." *North Carolina Ecological Services*. Retrieved February 14, 2012. http://www.fws.gov/nc-es/plant/rllooses.html
[240] U.S. Fish & Wildlife Service. "Schweinitz's sunflower (Helianthus schweinitzii)." *North Carolina Ecological Services*. Retrieved February 14, 2012. http://www.fws.gov/nc-es/plant/schwsun.html
[241] U.S. Fish & Wildlife Service. "Smooth Coneflower (Echinacea laevigata)." *North Carolina Ecological Services*. Retrieved February 14, 2012. http://www.fws.gov/nc-es/plant/smooconefl.html

Article 25) prohibit the takings of state-listed species, but do not limit the rights of a landowner in the lawful management of his or her land. In the area underlain by the Triassic Basin, 53 species are listed by the state as endangered or threatened in North Carolina. Of these, 32 are plants.

State-listed animals

Endangered, threatened and special concern species of mammals, birds, reptiles, amphibians, freshwater fishes, crustaceans and freshwater and terrestrial mollusks have limited legal protection status in North Carolina under the North Carolina Endangered Species Act (G.S. 113, Article 25). Of the 53 species listed by the state as endangered or threatened in North Carolina, 21 are animals.

Potential impacts to fish, wildlife and important natural areas based on studies from other states

At this time, there is insufficient information to predict specific impacts of natural gas drilling and production to fish, wildlife and important natural areas in North Carolina. This section describes research on impacts that have occurred in other oil and gas producing states. The potential impacts of natural gas exploration and production to fish, wildlife and important natural areas are organized within this section into two major types of impacts: land use changes and exposure to spills, releases and air emissions. Water withdrawals and introduction or expansion of invasive species would result in additional impacts that are not discussed here.

Natural gas drilling operations on public lands

Lands that are owned by the government, such as state parks and game lands, are not necessarily excluded from natural gas drilling. In 2011, Ohio Gov. John Kasich and the State Legislature opened up state parks for oil and gas drilling. The state "will earn at least 30 percent of royalties from land leases," and the proceeds are earmarked for improvements on the state's lands.[242]

Drilling has taken place in Pennsylvania state forests since 1947, and the state benefits from royalties and bonus payments associated with that drilling. Until 2009, "oil and gas revenue had been reserved for conservation, flood control and recreation purposes."[243] In 2009, Pennsylvania's government "took more than $399 million from the fund to help balance the next two budgets." More than 700,000 acres of Pennsylvania state forests have been leased.[244] Drilling also occurs on state game lands in Pennsylvania. Although the State Game Commission

[242] Guillen, Joe. "Drilling in state parks for oil and gas: Whatever happened to?" *The Plain Dealer.* January 14, 2012. Retrieved February 26, 2012 from http://blog.cleveland.com/metro/2012/01/drilling_in_state_parks_for_oi.html.

[243] Detrow, Scott. "Can Pennsylvania's State Forests Survive Additional Marcellus Shale Drilling?" StateImpact. September 12, 2011. Retrieved February 26, 2012 from http://stateimpact.npr.org/pennsylvania/2011/09/12/can-pennsylvanias-state-forests-survive-additional-marcellus-shale-drilling/.

[244] Ibid.

"owns 1.4 million acres of game lands, it does not always own the mineral rights beneath them, so private owners can lease them out to gas companies."[245]

Federal lands are also used for natural gas exploration and production. The Bureau of Land Management (BLM) issues leases for natural gas development on lands managed by the BLM and other federal agencies, such as the U.S. Forest Service. The BLM is currently considering regulations that would require disclosure of information about chemicals used in hydraulic fracturing on federal lands.[246] Federal lands under the stewardship of the U.S. Army Corps of Engineers at Falls Lake and B. Everett Jordan Lake, including areas leased to the State of North Carolina, could also be subject to BLM leasing decisions.

Proposed legislation in New York would ban hydraulic fracturing in state parks and forests.[247] In Ohio, the Department of Natural Resources has proposed rules that "would require natural gas and oil companies to stay at least 300 feet – the length of a football field – from campgrounds, certain waterways and sites deemed historically or archaeologically valuable."[248]

Impacts due to land disturbance

The exploration and production of natural gas can disturb a large amount of land as oil and gas operators develop gravel access roads, well pads, utility corridors, compressor stations and other necessary infrastructure. In the process of natural gas extraction and production, land is graded and cleared to develop well pads, access roads and utility corridors for water and electrical lines, gas gathering lines, and compressor facilities.

The New York Draft Environmental Impact Statement includes industry estimates of the average size of a multi-well pad. During drilling and hydraulic fracturing, the average well pad is estimated to be 3.5 acres. Once production begins at the well pad, a portion of the area used during the drilling and fracturing phase is partially reclaimed (as required by law in New York), and the remaining well pad size is estimated to be 1.5 acres on average.

The NYSDEC also contains industry estimates for the total land disturbed for well pads, including land disturbed for access roads and utility corridors. According to the industry estimates in the NYSDEC, during drilling and hydraulic fracturing, the average total land disturbance is 7.4 acres per well pad. The total acreage that remains disturbed during the production phase is 5.5 acres on average per well pad.

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[245] Seelye, Katharine Q. "Gas Drillers Invade Hunters' Pennsylvania Paradise." *The New York Times*. November 11, 2011. Retrieved February 26, 2012 from http://www.nytimes.com/2011/11/12/us/pennsylvania-hunting-and-fracking-vie-for-state-lands.html?pagewanted=all.

[246] Fugleberg, Jeremy. "First-ever federal fracking rules draw mixed Wyoming reviews." *Casper Star-Tribune*. February 16, 2012. Retrieved February 26, 2012 from http://trib.com/news/state-and-regional/first-ever-federal-fracking-rules-draw-mixed-wyoming-reviews/article_d0c16030-a105-51bf-8727-7c7aea09f031.html.

[247] Phillips, Susan. "New York's Proposed Fracking Regs Much Tighter than Pennsylvania's." StateImpact. July 1, 2011. Retrieved April 15, 2012 from http://stateimpact.npr.org/pennsylvania/2011/07/01/new-yorks-proposed-fracking-regs-much-tighter-than-pennsyvlanias/.

[248] *The Huffington Post*. "Ohio Fracking: State Agency Proposes Rules for Drilling in State Parks." April 12, 2012. Retrieved April 15, 2012 from http://www.huffingtonpost.com/2012/04/12/ohio-fracking-rules-proposed_n_1421400.html.

Natural gas production in the Triassic Basins could result in more land disturbance for the development of utility corridors for transmission lines than other states have experienced. There are fewer transmission lines in this state than in others that are already experiencing oil and gas extraction activities.

The estimates in the NYSDEC's Draft Generic Environmental Impact Statement do not include land disturbance for surface water impoundments, which have surface acreage of up to five acres. Each surface water impoundment can serve multiple well pads. At least one other estimate does include this land disturbance, and reports a higher amount of total land disturbance than the NYSDEC. The Nature Conservancy conducted a study in 2010 on the effects of horizontal hydraulic fracturing in Pennsylvania on high priority conservation areas. The study included an assessment of aerial photography of 242 Pennsylvania natural gas well locations, using data from the Pennsylvania Department of Environmental Protection, both before and after development. The study reported that nearly nine acres of land was disturbed per well pad (3.1 acres on average for the well pad and an additional 5.7 acres for roads, water impoundments and utility corridors for pipelines).[249]

Land disturbance associated with natural gas drilling, extraction and production activities could have a significant adverse impact on habitats and on the species that live both in the area that is disturbed and in neighboring areas, such as those described below.

Habitat fragmentation and habitat loss

Land disturbance can cause habitat fragmentation and habitat loss. Habitat fragmentation is the alteration of habitat that results in changes in area, configuration or spatial patterns from a previous state of greater continuity. Habitat loss is the conversion of areas of habitat to uses not compatible with the needs of wildlife. Habitat degradation is the diminishment of habitat value or functionality. Habitat fragmentation and habitat loss can lead to reduction in the total area of habitat, the isolation of one habitat unit from other units of habitat, and the separation of populations.

Habitat fragmentation and loss can occur naturally through events such as forest fires and volcanoes, but it can also be caused by the construction of well pads, access roads, pipelines and other infrastructure necessary for natural gas exploration and production.

Habitat connectivity is important; many wildlife species need to be able to move among various habitats to survive. For instance, many amphibians breed in wetlands but spend most of their lives in uplands away from wetlands. Therefore amphibians have different habitat requirements at different times of the year. Alterations to either of these habitats or barriers that would prevent them from moving between the two habitats will impact amphibians and other species that depend on habitat connectivity.

In addition to habitat loss and degradation, the development of natural gas drilling and production, including development of the necessary support infrastructure such as pipelines,

[249] NYSDEC, p. 6-76.

access roads and compressor stations, can impact wildlife through increased mortality, increased edge habitats and increased traffic, noise, lighting and air emissions.[250]

Forests provide ecological, economic and social benefits such as water quality protection, air quality enhancement, flood protection, pollination, pest predation, wildlife habitat and diversity, and opportunities for recreation. Large, continuous forest patches are particularly valuable. Forest cover helps maintain water quality, and forests and forestry practices are vital to the long-term sustainability of clean and affordable drinking water.

Although forestland is common throughout the Triassic Basin, current land development practices have already resulted and will continue to result in losses of large, contiguous forested areas. As forests are fragmented, the populations of species that depend on interior forests decline. Protecting remaining patches of forests is therefore critical.

Forests may be fragmented as a part of the land disturbance for natural gas drilling operations. Lands adjacent to well pads can be affected by natural gas extraction, even if they are not directly cleared, through the fragmentation of habitats and changing conditions for sensitive species that depend on interior forest conditions. Interior forest species may avoid edges because of the increased risk of predation or because of changes in canopy cover, humidity and light. Some species, such as invasive plants, thrive on forest edges, displacing native species. Land disturbance increases these edge habitats, and this type of disturbance is referred to as the “edge effect.”

According to the NYSDEC, “research has shown measurable impacts often extend at least 330 feet (100 meters) into forest[s] adjacent to an edge.”[251] A professor of wildlife resources at Penn State, Margaret Brittingham, is beginning to study the effects of the edges created by drilling in Pennsylvania game lands on flora and fauna. Dr. Brittingham “expects that some wildlife populations, like deer, are expected to increase after the drillers leave, but that songbirds, salamanders and frogs and other amphibians that help maintain a forest’s ecological balance are likely to decline.”[252]

The density of wells per well pad can either aggravate or mitigate the land disturbance impacts of the natural gas operation. More wells per pad equates to less land disturbance and more limited impacts on the landscape. In The Nature Conservancy’s 2010 study, the average well pad density was two wells per pad. Although gas drilling operators may eventually install more wells on each pad, two are initially drilled “as companies quickly move on to drill other leases to test productivity and to secure as many potentially productive leases as possible” before those leases expired (typically after five years if no drilling occurs).[253] If these wells are productive, gas operators will return to drill additional wells in the future.[254]

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[250] NYSDEC, pp. 6-67 – 6-69.
[251] NYSDEC, p. 6-75.
[252] Seelye, 2011.
[253] The Nature Conservancy. “Pennsylvania Energy Impacts Assessment Report 1: Marcellus Shale Natural Gas and Wind.” p. 13.
[254] The practice of drilling two wells initially and returning to the well pad after the wells proved productive was also mentioned by staff members of the Pennsylvania DEP.

The study compared three drilling scenarios for Pennsylvania (low, medium and high) and found that the most likely drilling scenario in Pennsylvania would result in a density of one well pad per 386 acres. This could be different in North Carolina, if a regulatory structure were developed that required a certain density of well pads, as does New York State. Some of the findings from The Nature Conservancy's study were:

- A majority of projected well locations were found in forests (64 percent for each of the three development scenarios). By 2030, between 34,000 and 82,000 acres of forest cover could be cleared by new Marcellus gas development in Pennsylvania, creating new forest edges "where the risk of predation, changes in light and humidity levels, and expanded presence of invasive species could threaten forest interior species in 85,000 to 190,000 forest acres."[255] The report recommends locating energy infrastructure toward the edges of large forest patches.
- Between 300 and 750 well pads could be located within a half mile of "exceptional value" streams, the Department of Environmental Protection's highest water quality designation.
- Nearly 40 percent of Pennsylvania's globally rare and Pennsylvania threatened species can be found in areas with a high potential for Marcellus shale gas development.

The report projects extensive overlaps between Marcellus development and state forests, parks and game lands.

The NYSDEC concluded that "for each acre of forest directly cleared for well pads and infrastructure in New York, an additional 2.5 acres can be expected to be indirectly impacted,"[256] because of the edge effect. This would have a high impact on interior forest bird species.

Forest matrix blocks are areas that "contain mature forests with old trees, understories, and soils that guarantee increased structural diversity and habitat important to many species."[257] Within these forest matrix blocks are smaller ecosystems, such as wetlands and streams, which depend on the forest for their long-term health. The New York State Department of Environmental Conservation assessed the 2010 work of the New York Natural Heritage Program in identifying New York's forest matrix blocks and predicting corresponding forest connectivity areas. NYSDEC concluded that 57 percent of the area underlain by the Marcellus shale in New York is forested, and it is likely that forests in New York would experience negative impacts similar to those predicted in Pennsylvania from high-volume hydraulic fracturing. NYSDEC reports that "In order to minimize habitat fragmentation and resulting restrictions to species movement in the area underlain by the Marcellus, it is recommended that forest matrix blocks

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[255] The Nature Conservancy. "Pennsylvania Energy Impacts Assessment Report 1: Marcellus Shale Natural Gas and Wind." p. 6.
[256] NYSDEC, p. 6-81.
[257] NYSDEC, p. 6-82.

be managed to create, maintain, and enhance the forest cover characteristics that are most beneficial to the priority species that may use them."[258]

In North Carolina's Triassic Basins, there are greater than 550,000 acres of forested land. Within the Dan River Basin, 56 percent of land is forested; in the Deep River Basin, 64 percent of land is forested; and in the Davie Basin, 49 percent of land is forested.

Secondary and cumulative impacts

In addition to the direct impacts of gas development, activities associated with gas production could also have secondary and cumulative impacts. "Secondary impacts" describes the predictable indirect impacts attributable to an activity. Secondary impacts may occur later in time or at a distance from the direct impacts; one example would be the impacts of constructing temporary housing for oil and gas workers. "Cumulative impacts" refers to the collective impacts attributable to a number of similar projects. Often individual impacts have negligible effects on wildlife and natural areas, but the cumulative effects over time from many small projects can greatly impact natural resources.

Like any other development activity, clearing, grading and road-building associated with natural gas production can harm threatened and endangered species by physically altering the species' habitat. Some species, such as turtles or mussels, may be unable to avoid direct impacts due to a lack of mobility. Land-disturbing activities can damage nesting and spawning areas or result in the loss of eggs and young animals. All of these impacts can result in a loss of future productivity. Increased vehicle traffic can also impact threatened and endangered species through direct mortality. Species may also be impacted by exposure to spills of fluids or wastewater from the drilling or hydraulic fracturing processes.

Impacts associated with drilling pads and associated infrastructure can potentially be reduced through careful planning. Care in siting drilling pads and infrastructure can limit direct impacts to high quality natural communities and rare plants. However, care must be taken to avoid the indirect effects of air pollution, water pollution and other impacts that can affect adjacent areas. Roads, gathering lines and other utility lines have the potential to impact wildlife and habitats through direct land alteration and habitat fragmentation. The cumulative effects of multiple utility corridors and new roads can greatly reduce the quality of natural communities. Efforts to combine utility corridors, reduce stream crossings, avoid impacts to large forest blocks and avoid wetland impacts will be important steps to reducing the overall impacts from natural gas production in the Triassic Basins.

Invasive species

The extraction and production of natural gas can increase invasive species problems through three main pathways: creation of edges due to land disturbance, vehicles and equipment transport, and surface water transport. Invasive plants readily colonize disturbed areas and habitat edges. Once established, invasive plants continue to spread to adjacent habitats. For example, invasive vegetation like privet (*Ligustrum* spp.) can also establish itself in forests.

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[258] NYSDEC, p. 6-83.

Invasive plant species are aggressive competitors and can significantly reduce the diversity of native plant and animal species.[259]

Any activity involving land disturbance, including well pad construction, access roads and surface impoundments for fresh water storage, has the potential to introduce and transfer invasive species. Machinery and equipment may come into contact with invasive species and carry them via tires, buckets or other parts of the equipment to another location on site, a separate site or a location in between.[260]

Invasive species are not limited to terrestrial habitats. The transportation of surface water across long distances to supply hydraulic fracturing operations presents the opportunity to transfer invasive aquatic plant and animal species within North Carolina. If spills or discharges occur during truck accidents or freshwater pipeline leaks, invasive species may be transferred from one watershed to another. One notable example is hydrilla (*Hydrilla verticillata*), a submersed aquatic plant native to Africa that forms nearly impenetrable mats of stems and leaves at the water's surface. Hydrilla crowds out beneficial native vegetation and causes changes in fish populations and other aquatic ecology. Hydrilla was introduced to the United States as an aquarium plant but is now "the most serious weed threat in North Carolina's inland waters."[261]

Potential impacts from spills, releases and air emissions

Spills will occur with any natural gas drilling and production in North Carolina. Along with violations for sedimentation and erosion control, spills were one of the two most common types of violations found by the Pennsylvania Department of Environmental Protection in gas drilling operations.[262] A number of different components of natural gas exploration and drilling may be spilled, including hydraulic fracturing fluids, drilling muds, wastewater and freshwater. The impact of spills can be compounded by insufficient stormwater controls. If spills occur before or during rain events, runoff can carry spilled fluids into surface waters.

Spills of fluids related to gas drilling operations

In oil and gas production, spills can occur at a number of different points in the process. Spills can occur during transportation of hydraulic fracturing fluids or drilling wastes. Spills can also occur on the well pad due to equipment malfunction or failure of spill prevention measures. Gas production requires storage pits or tanks for production fluids and waste materials (both wastewater and solid waste). Spills associated with storage structures can occur due to structural failures or overtopping of open pits. In any of these situations, a spill could enter a nearby stream in the absence of adequate containment systems.

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[259] New Hampshire Department of Transportation. *Best Management Practices for Roadside Invasive Plants.* 2008. Retrieved March 6, 2012 from http://www.fws.gov/northeast/cpwn/pdf/activities/InvasiveSpecies/BMPsforRoadsideInvasivePlantsNH.pdf.

[260] NYSDEC, p. 6-86.

[261] North Carolina Agricultural Extension Service. "Hydrilla: A Rapidly Spreading Aquatic Weed in North Carolina." Publication Number AG-449. North Carolina State University, 1992. Retrieved March 6, 2012 from http://www.weedscience.ncsu.edu/aquaticweeds/hydrilla.PDF.

[262] Personal communication, February 3, 2012.

Aquatic environments may be sensitive to the contamination associated with natural gas exploration and production, such as spills of hydraulic fracturing fluids, drilling wastes or even freshwater withdrawn for use in hydraulic fracturing if the water is of a lower quality than the receiving water. Hydraulic fracturing fluids may include toxic constituents, as described in Section 4.A, that are harmful to fish and wildlife depending on the concentration of the chemicals released to the environment. Wastewater from hydraulic fracturing may include the components of the hydraulic fracturing mixture as well as naturally occurring radioactive materials (NORMS) from the shale formation and high levels of chlorides.

A recent example of such a spill occurred in April 2011 in Leroy Township, Pa., when a mechanical failure caused the operator to lose control of a wellhead during hydraulic fracturing. Ten thousand gallons of fluids from the well mixed with rainwater and entered Towanda Creek, a tributary of the Susquehanna River, and an unnamed tributary of Towanda Creek.[263] The berm around the exterior edge of the well pad, designed to contain stormwater and spills, had been damaged by a truck shortly before the release and the berm failed.[264]

According to a press release from the Pennsylvania Department of Environmental Protection (DEP), “Chesapeake took two days to stop the flow from the well and four days beyond that to bring the well fully under control.”[265] The day after the operator lost control of the well, DEP detected “levels of total dissolved solids, chlorides and barium that were higher than background levels at the mouth of the tributary, where it enters Towanda Creek. Subsequent testing further downstream and on the following days showed these levels returned to normal background levels.”[266] According to a report by a consultant hired by Chesapeake, the spill did not cause any long-term damage to Towanda Creek. Chesapeake has indicated that it is making operational improvements to ensure this type of failure does not happen again, including marking berms so that truck drivers are better able to see them. This incident is just one example of how a spill from a drilling site can enter surface waters.

The impact of a spill to surface waters would depend on the nature and toxicity of the release. Potential impacts to aquatic life could include fish kills and injury to other aquatic plants and animals. A spill of approximately 8,000 gallons of hydraulic fracturing fluid from a broken pipe into Stevens Creek and a wetland in Dimock, Pa., on Sept. 16, 2009, resulted in a fish kill.[267] Contamination of fish species traditionally caught for human consumption could also affect availability of those species as a food source. In cases of threats to human health, the N.C. Department of Health and Human Services issues fish consumption advisories to notify people to limit consumption or avoid eating fish that may contain contaminants.

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[263] Sunday, Kevin. “DEP Fines Chesapeake Appalachia $565,000 for Multiple Violations.” Pennsylvania Department of Environmental Protection. February 9, 2012. Retrieved February 26, 2012 from http://www.portal.state.pa.us/portal/server.pt/community/news_releases/14288.
[264] Personal communication with Brian Grove of Chesapeake Energy.
[265] Sunday, 2012.
[266] Ibid.
[267] McConnell, Steve. “DEP notes 5 violations for gas drilling spill.” *Wayne Independent*. September 24, 2009. Retrieved April 18, 2012 from http://www.wayneindependent.com/news/x1128380990/DEP-notes-5-violations-for-gas-drilling-spill.

Some reports have also linked spills from gas production operations to death or illness in livestock, dogs and wildlife. In 2009, 17 cattle in Louisiana died in a pasture near a well that was being hydraulically fractured. According to the *Shreveport Times*, "Witnesses reported hearing [the cattle] bellowing and seeing them bleeding before they fell over dead."[268] The Louisiana Department of Environmental Quality (DEQ) determined that "fluid leaked from the well pad, then ran into an adjacent pasture after a rain." A toxicologist hired by DEQ determined that the cattle deaths "were consistent with and suggestive of petroleum hydrocarbon ingestion with secondary aspiration pneumonia."[269] In response to the incident, DEQ fined the drilling operator and a contractor for violating several state rules.[270] Although both companies denied that the material discharged from the well site killed the cattle, the drilling operator and the contractor each paid $22,000 in fines and the drilling operator compensated the cattle owners for their losses.[271]

Contaminated freshwater

The release of freshwater from a leaking pipeline or during transportation may be detrimental to aquatic species and habitats if it enters a surface water of higher quality. For instance, a spill of water from a Class C water to a high quality stream may contaminate the high quality stream and adversely impact the aquatic species within it.

Sedimentation and erosion

In addition to spills that release contaminants to surface waters, land disturbance associated with gas production activities can damage surface waters through erosion and sedimentation. If disturbed areas are not effectively stabilized, rain events cause soil erosion. Stormwater runoff then carries excess sediment and contaminants on the land surface into nearby surface waters. Lack of effective sedimentation and erosion control measures can damage wetlands and streams in at least two ways. Sedimentation pollution buries aquatic organisms, disrupting the food chain and altering habitat. The excess stormwater that flows off unstabilized areas can also scour out stream banks and bottoms, which damages aquatic habitat in other ways. Effective sedimentation and erosion control measures are necessary to reduce the impacts of erosion and sedimentation on aquatic species and their habitats.

At the same time Chesapeake Energy was fined for the spill in Leroy Township, Chesapeake was fined for a March 2011 incident in West Branch Township, "where sediment discharged into a stream classified as high quality," and for 2010 violation that impacted a wetland and allowed sediment to enter Sugar Creek in North Towanda Township.[272] In the first incident, an access road and well pad were constructed without sufficient erosion controls and heavy rain caused sediment to run-off into a stream. The sediment load eventually impacted a local water

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[268] Welborn, Vickie. "Chesapeake, Schlumberger fined $22,000 each in cattle deaths." *Shreveport Times*. March 26, 2010. Retrieved February 26, 2012 from http://pqasb.pqarchiver.com/shreveporttimes/access/1994311381.html?FMT=ABS&date=Mar+26%2C+2010.
[269] Ibid.
[270] Ibid.
[271] Ibid.
[272] Ibid.

authority's water treatment filters. In the second incident, part of the well pad was built in a wetland. The production company filled a third of an acre of wetlands without authorization, causing temporary impacts to the wetland through erosion and allowing sediment to enter Sugar Creek.[273]

Impacts to wildlife, livestock and pets

There is a limited amount of research on the impacts of natural gas drilling on wildlife, livestock and pets. This could be due in part to nondisclosure agreements between injured parties and corporations that prevent information from being documented. One peer-reviewed study researched the impacts of gas drilling on human and animal health. Their research is essentially a collection of case studies and the authors acknowledge the study "is not an epidemiologic analysis of the health effects of gas drilling."[274] The authors documented cases of animal and owner health problems with potential links to gas drilling and interviewed animal owners living near gas drilling operations in six states. The authors researched 24 cases involving spills associated with drilling operations including wastewater spills, stormwater runoff from a well pad, drilling fluids that spilled off a well pad during a blow out, and hydraulic fracturing fluids spilled from a holding tank. According to this study, reproductive problems were "the most commonly reported symptoms."

The Bamberger study cited above also noted the potential for impact on food supply. The authors

> "documented cases where food-producing animals exposed to chemical contaminants have not been tested before slaughter and where farms in areas testing positive for air and/or water contamination are still producing dairy and meat products for human consumption without testing of the animals or the products."[275]

In addition to the risk of spills, open pits and impoundments for storage of drilling wastes and produced water may attract wildlife. If untreated wastewater is stored in settling ponds, wildlife species that swim in, drink from or consume vegetation growing in the wastewater may be impacted by the chemicals and contaminants in this wastewater. If these animals are subsequently harvested by hunters, these potential wildlife health impacts may impact humans as well.

Potential impacts from noise and light pollution

Some researchers have expressed concerns about the impacts to wildlife from noise and light pollution (the extent of these impacts is discussed in Section 6). Research in the Canyon Wildlife Area of New Mexico, where thousands of natural gas wells are located, found that some species avoided eating the seeds of pinyon pines in noisy areas. Researchers found that mice preferred noisy sites while western scrub jays avoided noisy sites. Pinyon pines were four times

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[273] Ibid.

[274] Bamberger, Michelle and Robert E. Oswald. "Impacts of Gas Drilling on Human and Animal Health." *New Solutions*, vol 22(1) 51-77, 2012.

[275] Bamberger and Oswald, p. 67.

as abundant in quiet areas, showing that "manmade noise not only affects animal behavior, buy may impact the future of pinyon pines."[276]

Artificial lights from natural gas drilling sites may also impact nocturnally migratory birds or other wildlife. Lights are required for safety on the rig during night operations, but light pollution can confuse wildlife. Additional research is needed to fully understand these impacts and ways to mitigate them. Some research indicates that lights of certain wavelengths may be less disorienting to migratory birds while providing sufficient light for human needs.[277]

Noise and light pollution may alter animal behavior in ways that affect the distribution and potentially the survival of some species. The types of animals that may be impacted include birds, mammals, reptiles, amphibians, insects and other invertebrates. The alteration of animal behavior may in turn affect the distribution of plants; many animal species are directly or indirectly involved in the distribution of seeds through their feeding and migration patterns.

Surface water withdrawals

Healthy aquatic ecosystems depend on natural flow patterns in streams and rivers. Aquatic ecosystems can be adversely impacted by changes to water quantity or changes to stream flow resulting from water withdrawals for hydraulic fracturing. Water withdrawal during drought conditions when flows are already low could be particularly harmful to aquatic ecosystems and sensitive species in particular. During hydraulic fracturing for shale gas production, approximately three to five million gallons of water is used per well.

Potential impacts to recreational fishing and hunting

The process of extracting and producing natural gas or oil can affect recreational activities, such as fishing and hunting, that occur throughout the Triassic Basins. In addition to reduced populations of fish and game, the land disturbance, noise, visual impacts and increased truck traffic associated with natural gas production could alter landscapes and animal behavior, disturb the peaceful environment associated with public recreation areas, and result in loss of access to fishing and hunting areas. The potential impacts to recreational fishing and hunting are described in greater detail in Section 6D, *Potential impacts on recreation activities*.

Conclusions related to the protection of fish, wildlife and important natural areas

If natural gas drilling and production occurs in North Carolina, DENR recommends that fish, wildlife and important natural areas should be offered some protection through establishing setbacks and areas prohibited from drilling. The development of specific setbacks and prohibited areas will require further work in collaboration with a number of stakeholders. To address secondary and cumulative impacts, DENR has recommended that the General Assembly require oil and gas operators present a drilling unit management plan to the regulatory agency for approval. State agencies would review potential secondary and

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[276] Sanders, Anna. "Study Suggests Manmade Noise Affects Plant Dispersal and Flower Pollination." *Audubon Magazine*. March 20, 2012. Retrieved April 15, 2012 from http://magblog.audubon.org/study-suggests-manmade-noise-affects-plant-dispersal-and-flower-pollination.

[277] Poot, Hanneke, et al. "Green Light for Nocturnally Migrating Birds." *Ecology and Society*. 2008. Retrieved April 15, 2012 from http://www.ecologyandsociety.org/vol13/iss2/art47/.

cumulative impacts such as forest fragmentation and harm to important natural areas and develop requirements for the minimization of secondary and cumulative impacts.

I. Management and reclamation of drilling sites (including orphaned sites)

Definitions

Under North Carolina's Oil and Gas Conservation law (North Carolina General Statutes Chapter 113, Article 27), once an exploration well is completed or stops producing, notice is given to the Division of Land Resources (DLR) along with a fee paid for a permit to plug and abandon the well. DLR issues a permit and conducts a final inspection of the abandoned well. Proper abandonment of the well will result in the return of the bond carried on the well during the entire well lifecycle.

Orphaned oil and gas wells are wells that have been plugged, but not inspected by DLR; wells that have been improperly abandoned without the correct plugging; and wells that have not been plugged and have been left as an open hole.

History of oil and gas exploration in North Carolina

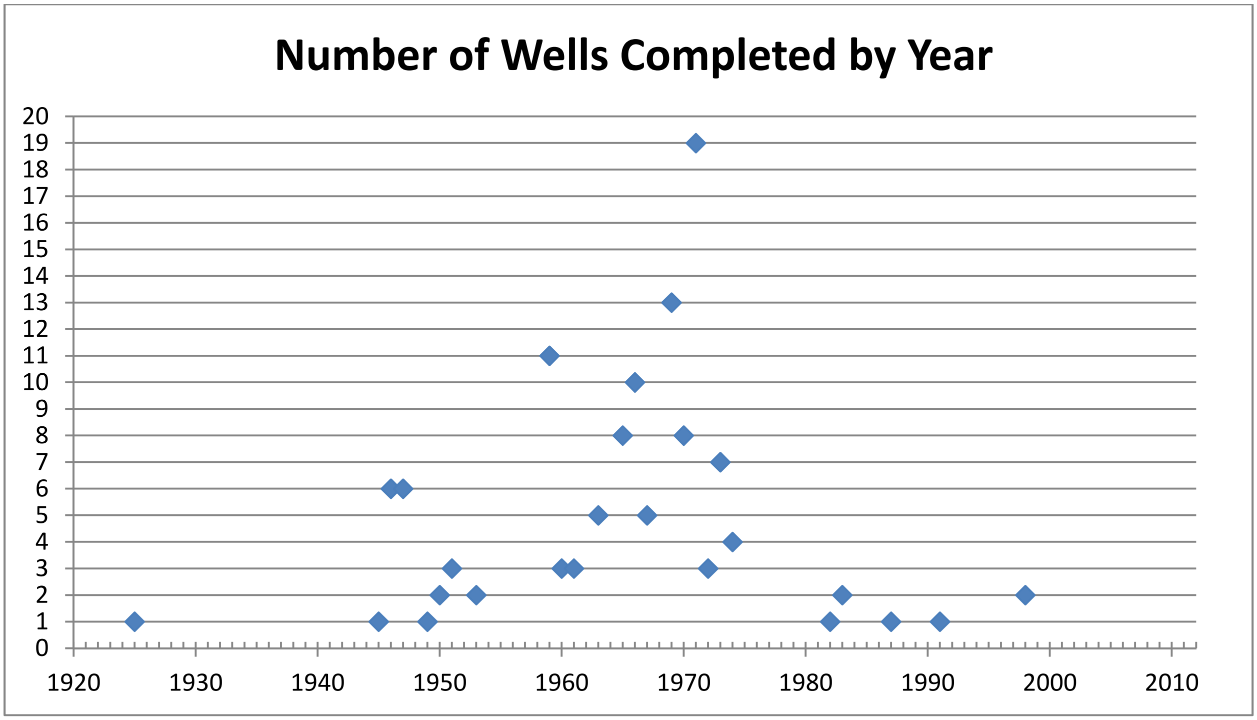
The history of oil and gas exploration in North Carolina spans more than 80 years, with the earliest oil well drilled in 1925 in Craven County (Great Lakes #2 – API No.: 32-049-1). The most recent oil and gas wells were drilled in 1998 in Lee County (Simpson #1 – LE-OT-1-98 and Butler #3 – LE-OT-2-98).

To date, 128 oil and gas exploration wells have been completed in North Carolina. Figure 4-10 shows the number of wells completed per year using data from N.C. Geological Survey Information Circular 22 – "Exploration Oil Well of North Carolina 1925 – 1976," compiled by James C. Coffey (1977). The 120 wells listed in that publication have been increased to 128 to include seven wells completed from 1976 to 1998 and the addition of another well drilled in Pamlico County in 1947 (API No.: 32-137-0004).

Oil and gas exploration wells have been drilled in 23 counties. These are listed in rank order: Onslow (22), Brunswick (16), Carteret (16), Dare (15), Hyde (10), Lee (8), Pender (8), Beaufort (5), Tyrrell (5), Pamlico (4), New Hanover (3), Camden (2), Craven (2), Currituck (2), Washington (2), Bertie (1), Bladen (1), Duplin (1), Gates (1), Hertford (1), Jones (1), Pasquotank (1) and Wilson (1).

Over the years, several exploration campaigns have concentrated on one or two adjacent counties. From 1945 to 1947, Carteret, Pamlico and Dare counties were the targets. In 1959, the focus was on Hyde and Onslow counties. By 1963, it was Beaufort; Dare and Hyde in 1965; and in 1966-67 Pender and Onslow. Exploration expanded in 1969, when13 wells were drilled in nine different counties. By the early 1970s, the focus had narrowed to Onslow and Brunswick; in 1971 it was Brunswick (11 of 19), Dare and Tyrrell; and in 1972 to 1974 Tyrrell, Carteret, Dare and Lee. Since 1974, eight wells have been drilled, all of them in Lee County.

Figure 4-10. Time series of the number of exploration oil and gas wells completed in North Carolina. The most active exploration years, those with 10 or more wells completed are: 1971 with 19; 1969 with 13; 1959 with 11 and 1966 with 10.



Oil and gas exploration well information held by the N.C. Geological Survey

Upon submission of an application for an oil and gas drilling permit, a permanent file is created for that well. The proposed well is assigned an American Petroleum Institute (API) number. This is a three-part number; the first two digits represent the state code, e.g. 32 for North Carolina. The second three-digit number is the county, e.g., 013 for Beaufort County. The third number represents the chronology of the well completion within the county, e.g., 1 for the first well in the county.

Only one well, drilled in Craven County in 1925, precedes the North Carolina Oil and Gas Conservation Act of 1945. Each well has a unique NCGS code and well name. Well files can include permit applications, issued permits, drilling reports, completion reports, well location maps, correspondence between the department and the owner, operator and/or driller, mud logs and all geophysical logs. These files are stored in locking metal filing cabinets in the Core Repository at the NCGS Raleigh Field Office on Reedy Creek Road in Raleigh. All well information is stored by county in chronological order, from first well drilled in the county to the latest.

A digital database of everything known about each oil and gas exploration well is also maintained. NCGS is currently using the ESRI ArcGIS 8.3 platform. Decidegrees of latitude and longitude are provided in the database for plotting in a GIS environment.

The explanation for the data fields is listed below. Note that the well locations are reported in degrees, minutes and seconds. One second of latitude (1/60 of one minute x 1/60 of one degree) equals 0.0003 of a degree.

0.0003 degrees x 111.195 km/degree x 62 miles/100 km x 5,280 ft/mile = 109 feet.

One-half second of latitude equals 50 feet. The well locations listed in the files are between 50 feet to 110 feet of the abandoned well location.

Oil and gas exploration well database data field explanation

Listed in the table below is the explanation of the data fields found in the oil and gas exploration well database.

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Data field explanations

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NCGS Code: alphanumeric code for the hole of interest, format is 2-letter county abbreviation, type of hole

(T=test; C=core; A=auger; P=producing (outdated water-well designation); and OT=oil & gas exploratory hole), sequence number within a given year, and year drilled.

PP 796: USGS Professional Paper 796 cross-reference number for the well.

Well Name: usually lease-name for oil & gas exploration wells

Other Code: company code, or other tracking code used to id the well.

Latitude: degrees, min, sec

Longitude: degrees, min, sec

Well datum: elevation of measuring point for logging, usually ground surface, but in the case of oiltests, is usually the KB (kelly bushing).

County: self-explanatory

Operator: owner of well

Depth: total depth of well

Drilled by: actual driller, not owner of hole

Date Drilled: full year, month, day

Logged by: geophysical logging contractor

Date logged: self-explanatory

Logs: listing of geophysical logs run on the borehole, "standard" abbreviations used, call if you need a list.

Samples: samples archived by NCGS, boolean field, true or false

Slides: paleontologic slides available, boolean field, true or false

Lith log: good quality lithologic log for the hole, boolean field, true or false

Cuttings: cuttings available, boolean field, true or false

Ctgs Interval: cuttings intervals archived

Core: core available, boolean field, true or false

Core Interval: core intervals archived

SWC: side wall cores (oiltests), boolean field, true or false

SWC Interval: side wall core intervals

Interval: continuation of side wall core intervals

Tops: formation tops picked, boolean field, true or false

Basement: bedrock reached, boolean field, true or false

BsmtLith: bedrock lithology

GW Grid: NC Ground Water Section grid coordinates for borehole (a filled field indicates a well that the Groundwater Section drilled or logged).

Ctgs Footage: total cuttings footage for hole.

Core Footage: total core footage for hole.

Bsmt depth: log depth of bedrock surface

Bsmt altitude: depth of bedrock, reference MSL

Type: type of hole, Welldata=municipal, industrial, and domestic water wells; Hardrock=mineral exploration tests, in piedmont/blue ridge;

Triassic=triassic basin holes; Oiltest=oil and gas exploratory holes.

Deci-long: decidegrees of longitude

Deci-lat: decidegrees of latitude

Summary

One hundred twenty-eight oil and gas test wells have been drilled in North Carolina. One hundred twenty-five wells have been abandoned in compliance with the Oil and Gas Conservation Act of 1945. The two wells drilled in 1998 are shut-in (completed but not in production) and both under a bond of $5,000 each. We do not know the method used to abandon the 1925 Craven County well.

For the 125 oil and gas test wells that have been plugged and abandoned, a paper folder for each test well is maintained by the DLR in secured filing cabinets at the NCGS Raleigh Field Office and Core Repository. Documents in each file include copies of permits, correspondences between the permittee and DLR, inspection reports by NCGS staff and documentation on the release of the bond, copies of the mud log, daily drilling reports and copies of all geophysical logs collected from the test well. By law, the test well files are to be kept confidential for one year, which can be extended to two years at the request of the permit holder. At this time, all documents are public records and can be viewed or copied by anyone. To arrange access to the oil and gas test well files, contact the NCGS.

J. Management of naturally occurring radioactive materials (NORMs)

Note to the reader: *This subsection was written with the assistance of the N.C. Department of Health and Human Services, Radiation Protection Section.*

Shale is a fine-grained sedimentary rock composed mostly of clay-size particles that settle out of a water column in a bay or deep ocean. Shale is a clastic sedimentary rock, which means it is made of tiny particles of weathered rocks and minerals. The two most resistant minerals to weathering are quartz and feldspar. In addition to the quartz and feldspar e more dense heavy minerals such as magnetite, ilmenite, zircon, pyroxene and amphibole can be incorporated into shale. Several types of pyroxene, amphiboles, feldspar and zircon are mildly radioactive.

Naturally occurring radioactive materials (NORMs) contribute to background radiation. Uranium (U) and Thorium (Th) are two of the most common radioactive elements that occur in most igneous, metamorphic and sedimentary rocks, in very low concentrations of 1 to 3 parts per million (ppm). These elements together with their decay daughters – Radium (Ra) and Radon (Rn) – have been associated with NORMs.

NORMs occur in both flowback and produced waters, because elements extracted from the shale or present in the formation water are brought up when flowback and produced water return to the surface. Each shale play appears to have a different pattern and range of levels for NORMs.[278] The existence of radioactivity in flowback water has been a major concern of environmental groups, particularly in the Marcellus shale play.[279] The U.S. EPA estimates that about 30 percent of oil and gas production sites have radionuclide levels of regulatory concern.[280]

The principal concern for NORMs in the oil and gas industry is that, over time, radiation can become concentrated in field production equipment, as sludge or sediment inside tanks and process vessels that have an extended history of contact with formation water, or in landfills in which sludge is disposed.[281] To address this concern, the Pennsylvania Department of Environmental Protection (DEP) conducted a study starting in 1991 to survey more than 400 oil and gas well sites, nine pipe yards and about 500 miles of dirt road that were sprayed with brine for dust suppression.[282] Their survey shows that about 60 percent of the well sites had readings at or below background levels. Thirty-four percent of the readings were within 10 microroentgens per hour (microR/hr) of background, and two percent were 21-54 microR/hr above background.[283] The level of background radiation varies, but from their evaluation, 94 percent of the sites were at or only two to three times background levels.

Several states have adopted regulations for NORMs. Louisiana, Texas, Arkansas and Michigan have set an action level of 50 microR/hr for contamination. The level for Mississippi is 25

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[278] Groat, C.G., Grimshaw, T.W. (2012) Fact-based regulation for environmental protection in shale gas development, The Energy Institute, The University of Texas at Austin, February 2012. http://energy.utexas.edu/ Regulations report is: ei_shale_gas_regulations120215.pdf
[279] Ibid.
[280] Otton, J. K., Zielinski, R.A. (2000) Simple techniques for assessing impacts of oil and gas operations on Federal Lands – a field evaluation at Big South Fork National River and Recreation Area, Scott County, Tennessee (online edition), USGS Open-File Report 00-499, 51 pp.
[281] Ground Water Protection Council and ALL Consulting, 2009.
[282] PA DEP (1991 and 1995) NORM Survey Summary was prepared as an article in April 1995 for the IOGA News. An earlier NORM Survey Summary was prepared September 1, 1992. File accessed from PA Oil and Gas Commission website.
[283] Ibid.

microR/hr.[284] Federal limits have not yet established.[285]

The U.S. Geological Survey has documented cases of NORM contamination with measured radium isotopes at oil and gas exploration and production sites in Oklahoma, Illinois, Kentucky, Wyoming, and Michigan.[286] As part of the USGS field investigations of sites on federal land, personnel measured radioactivity from gamma rays produced by the decay products of $_{226}$Ra (principally $_{214}$Bi) and $_{228}$Ra (principally $_{208}$Tl), but also gamma rays from $_{40}$K.

N.C. Geological Survey (NCGS) measurements and sampling

Under the legislatively mandated study, the NCGS borrowed two hand-held radiation counters to measure outcrops of shale rock in the Deep River and Dan River basins. Samples were also collected to be sent to geochemical laboratories for analysis of a full geochemical package of 63 elements, which has a uranium and thorium detection and limit of 0.1 parts per million.

The fieldwork occurred on a handful of days over several months. NCGS sampled roadcuts and quarry walls for radioactivity with the handheld meters and collected rock samples for split samples to test for total organic carbon and elemental isotope radiation. While geochemical analysis is not yet complete, the field measurements were conducted using the same method as Otton and Zielinski.

Drs. Kenneth Taylor and Jeff Reid of the NCGS were joined by Dr. Paul Olsen of Columbia University to take 54 measurements of the radioactivity of shale rock from the black shale Cows Branch Formation in the Dan River Basin along a 1,500 feet east-west exposure of the west pit in the Cemex Quarry north of Eden. Sites along the south-facing quarry wall were selected by Olsen and Taylor in order to sample all the darkest shale layers in the continuous section.

Taylor took two radiation measurements at each sampling location and Reid logged the measurement on a handheld GPS receiver with antenna. The locations were post-process by personnel in the North Carolina Geodetic Survey. The radiation measurements were reported in microR/hr.

The background radiation level was 6 to 10 microR/hr. Seven samples were at or equal to background: one sample at 9 microR/hr, four samples at 10 micro$/hr and two samples at 10.5 microR/hr. The highest value was 29 microR/hr (one value). The mean of the 54 samples has a radiation value of 14.8 microR/hr with a standard deviation of 3.7 microR/hr. Taking a level of 8 microR/hr as background, 19 samples are two times background and only one sample is greater than three times background. A plot of the observed radiation levels is shown in Figure 4-11.

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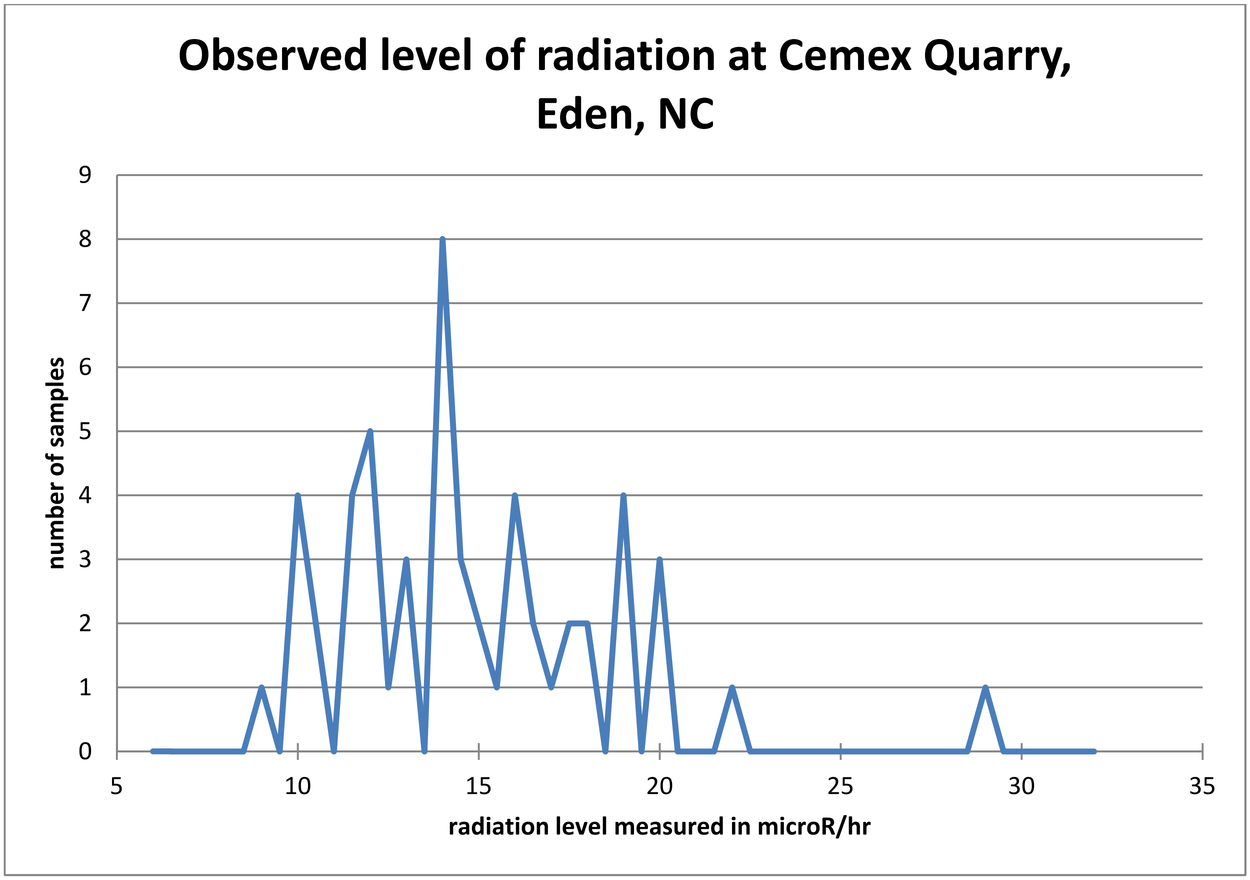
[284] Ibid.

[285] Groat and Grimshaw (2012) and Shale Gas Primer (2009).

[286] Otton and Zielinski (2000).

Figure 4-11. Observed radiation from shale rock along the south-facing quarry wall at the CEMEX mine north of Eden, N.C. The 1,500 foot quarry face is a continuous exposure of the Cows Branch Formation in the Dan River Basin.



K. Potential for increased seismic activity

This sub-section outlines the documented cases of increased seismic activity due to activities associated with oil and natural gas extraction. The full range of triggered or induced seismic activity from hydraulic fracturing to events triggered by deep-well disposal will be discussed. The Oklahoma Geological Survey in their position statement on this issue said,

> "Induced seismicity is the more colloquial term, but triggered seismicity is the more accurate term for earthquakes inadvertently cause by anthropogenic activities. This indicates that the stress released in the earthquake was accumulated through natural processes, but the mechanism that caused the stress release was due the affects of human activities."[287]

Actions taken by state and local governments to curtail the induced seismicity and prevent triggering of seismic events will also be outlined.

[287] Oklahoma Geological Survey, "Position Statement on Triggered or Induced Seismicity," April, 2012.

Earthquakes 101

An earthquake is a sudden motion or trembling of the earth caused by the abrupt release of slowly accumulated strain.[288] The ability to measure the size or strength of an earthquake has been a goal of seismologists since the 1930s. The Richter magnitude scale correlates a tenfold increase in the recorded amplitude of ground shaking to magnitude.[289]

In the mid 1970s, a new concept called seismic moment M_O was defined as the product of the shear modulus, μ, the average slip on a fault, *d,* and the area of the fault, *A*. By measuring the energy, *E*, in the waveforms, the following relationships are seen:

$$M_O = \mu dA \approx E/20000$$

This led to the development of a magnitude scale that was directly related to the size of the rupture caused the earthquake. The moment magnitude was also able to give a quantifiable value to large explosions, such as underground nuclear tests.

The moment magnitude scale is open-ended and earthquakes can range from the smallest at "-4" to the largest which are greater than magnitude "9". The smaller the earthquake, the higher the corner frequency, so to record successfully very small earthquakes, the data collection system must sample at rates of at least 10,000 samples per second.[290]

Does the process of hydraulic fracturing create or trigger earthquakes? The process of hydraulic fracturing involves pumping fluid under pressure into cracks in the surrounding rock; as these cracks expand, vibrations are generated and can be observed by sensitive geophones. Figure 4-12 shows the process of lowering a string of geophones from a wireline to record microseismic events produced by the cracking of the rock formation. These microseismic events have moment magnitudes in the range of "0.0" to "-2.5".[291]

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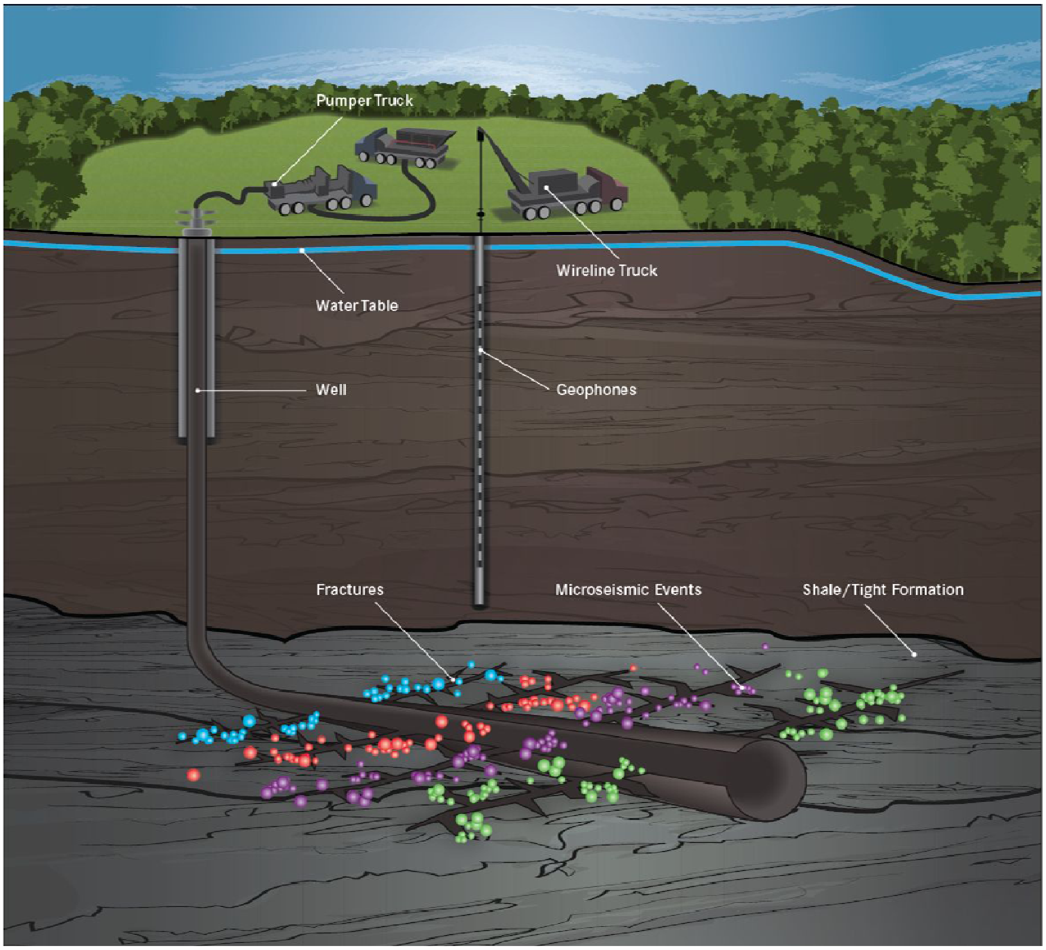
[288]Bates, R. L. and J. A. Jackson (editors). *Dictionary of Geological Terms – Third Addition.* American Geological Institute, Garden City, NY, 1984.
[289] Baig, A. and T. Urbancic. "Magnitude determination, event detectability, and assessing the effectiveness of microseismic monitoring program in petroleum applications." CGEC Recorder, February 2010, pg 22-26.
[290] Ibid.
[291] Ibid.

Figure 4-12. Colored spheres show the location of microseismic events generated by hydraulic fracturing.



Source: ESG Solutions[292]

Baig and Urbancic (2010) show that these microseismic events, which are recorded on a geophone string closer than 1,600 feet away, must have a moment magnitude of at least "-1.8." In terms of energy, an event of that size is 30 times smaller than a "-0.8." event and 21.87 billion times smaller than a "5.8." For reference, the Aug. 23, 2011, Mineral, Va. earthquake was moment magnitude "5.8" and it shook Raleigh and was felt along the East Coast from Georgia to Canada.[293]

The process of hydraulic fracturing generates very small earthquakes. As the fracturing occurs, the expanding crack is located by the seismic waves generated by the fracturing and recorded on the geophone string. An important job of microseismic monitoring companies is to notify the hydraulic fracturing contractor when cracks occur away from the horizontal lateral and the

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[292] ESG Solutions. "Hydraulic fracture mapping." 2012. https://www.esgsolutions.com.
[293] USGS. "Magnitude 5.8 – Virginia – 2011 August 23 17:51:04 UTC." *Significant Earthquakes 2011.* 2011. Retrieved from: http://earthquake.usgs.gov/earthquakes/eqinthenews/2011/se082311a/.

fracturing stage. In most cases, individual cracks can be located within tens of feet from several thousand feet away.

Possible case of seismicity induced by hydraulic fracturing

In 2011, the Oklahoma Geological Survey (OGS) investigated a citizen report of feeling several earthquakes during the night at a location near a hydraulic fracturing project.[294] Looking at seismograms for that day, about 50 earthquakes occurred during that time. Only 43 earthquakes were large enough to be located and the magnitudes ranged from 1.0 to 2.8 using the duration magnitude. Using the relation given earlier for the size of the microseisms created during hydraulic fracturing, these events are 900 to 27,000 times smaller than the felt earthquakes. The OGS analysis showed that shortly after hydraulic fracturing began, small earthquakes started occurring. Most of these earthquakes occurred within a 24-hour period after the hydraulic fracturing operations had ceased.[295] The OGS shows a strong correlation in both time and space as well as a reasonable fit to a physical model suggesting a possibility that these earthquakes were induced by hydraulic fracturing.

Several instances of triggered or induced earthquakes have been documented in the scientific literature. These include the Rocky Mountain Arsenal; Rangely, Colo.; Paradox Valley, Colo.; and the KTB Deep Well in Germany.[296] In each of these cases, strong correlations exist between the onset of fluid injection and the start of seismicity. There were also correlations between the well location and the location of the seismicity, which tended to be in close proximity to the well.[297]

The final correlation criteria require that there must be changes in fluid pressure at the depth of the earthquakes sufficient to encourage seismicity. In the case of the OGS investigation, the first fracture stage (between 9,830 and 10,282 vertical feet below the surface) was at an average rate of injection of 88.5 barrels per minute and at an average injection pressure of 4,850 pounds per square inch (psi). The earthquakes were about 1.5 miles away from the well and co-located with a group of small fault-bounded blocks.

Arkansas case of disposal wells inducing earthquakes

In September 2010, small earthquakes started occurring near the town of Guy in north-central Arkansas. Several thousand earthquakes migrated from the northeast to the southwest along a seven to nine mile linear trend over the next several months. On Feb. 27, 2011, a magnitude 4.7 earthquake occurred near the town of Greenbrier. To the south and east of Guy is the community of Enola, a place with a history of earthquake activity. In 1982, over a period of a

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[294]Holland, Austin. "Examination of Possible Induced Seismicity from Hydraulic Fracturing in the Eola Field, Garvin County, Oklahoma." Oklahoma Geological Survey, Open-File Report OF1-2011.
[295] Ibid.
[296] Ibid.
[297] Ibid.

few weeks, thousands of small earthquakes were recorded near there. In 2001, the ground began to shake again and more than 2,000 events occurred that year.[298]

In March 2011, two natural gas companies, Chesapeake Energy and Clarita Operating, agreed to temporarily suspend use of an injection wells for wastewater disposal in central Arkansas where the earthquakes persisted.[299] The companies stopped operations of the wells near Greenbrier and Gay only five days after the Greenbrier quake struck.

The Arkansas Oil and Gas Commission undertook an investigation and discovered that four disposal wells were located on a fault line – the northeast to southwest extension of the New Madrid Seismic Zone. After two of the four wells stopped operating in March 2011, the number of earthquakes sharply declined. A public hearing was held on July 26, 2011, and two draft orders were circulated to: 1. request an immediate cessation of disposal operations and order the plugging of the disposal well; and 2. request an immediate moratorium on any new or additional class II commercial disposal wells or Class II disposal well permits in certain areas.

Lawrence E. Bengal, director of the Arkansas Oil and Gas Commission, issued those two orders on Aug. 2, 2011.[300, 301] The moratorium closed one disposal well and had the direct effect of closing three other disposal wells in the 1,150 square mile area. A map of the moratorium area can be found on the Arkansas Oil and Gas Commission website.[302]

Ohio and another case of induced seismicity

Trucks have been transporting produced water to Ohio from the Pennsylvania gas fields since the Pennsylvania DEP asked drillers to stop disposing of flowback water at municipal wastewater treatment plants. Ohio had a number of underground injection wells for wastewater disposal that could accept waste from operations in another state. That all changed when a magnitude 4.0 earthquake struck the Youngstown-Warren area in Ohio on the last day of 2011.[303]

By Jan. 3, 2011, press reports quoted Dr. John Armbruster of Columbia University's Lamont-Doherty Earth Observatory saying that the earthquake and 11 minor earthquakes that followed it were due to the wastewater well.[304] What many did not know was that more than two weeks

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[298]U.S. Geological Survey. 2010-2011 Arkansas earthquake swarm Poster. http://earthquakes.usgs.gov/earthquakes/eqarchivees/poster/2011/20110228ARupdate.medium.jpg, published March 1, 2011.

[299]Eddington, S. "'Fracking' disposal sites suspended, likely linked to Arkansas earthquakes." Associated Press published by *Huffington Post* at www.huffingtonpost.com, March 3, 2011.

[300]Arkansas Oil and Gas Commission. "Request for an immediate cessation of disposal operations and order to plug a Class II Commercial Disposal Well." Order No. 180A-1-2011-07, August 2, 2011.

[301]Arkansas Oil and Gas Commission. "Request for an immediate moratorium on any new or additional Class II commercial disposal well or Class II disposal well permits in certain areas." Order No. 180A-2-2011-07, August 2, 2011.

[302]Arkansas Oil and Gas Commission. "Permanent Disposal Well Moratorium Area Map," Scale 1:300,000, compiled by Ramsey, J. 6/7/2011, Map date 6/20/2011.

[303]Associated Press. "Earthquake strikes in northeastern Ohio near Youngstown." December 31, 2011, 3:57 PM, updated: December 31, 2011, 5:56 PM.

[304]Sheeran, T. "Expert: wastewater well in Ohio triggered quakes." Associated Press, January 3, 2012.

earlier, Henry Fountain from *The New York Times* had reported that eight earthquakes in eight months had already struck the region and the experts who Mr. Fountain quoted in his article had already suspected a connection between the earthquakes and the disposal well.[305] Mark Niquette from Bloomburg News reported that while Ohio had stopped operations at five wells, the state's other 177 disposal wells would continue to be used.[306]

After researching the link between the seismic events in the Youngstown area and a brine disposal well, the Ohio Department of Natural Resources developed new standards for transporting and disposing of brine. The new requirements include a prohibition against drilling new wastewater disposal wells in the Precambrian basement rock formation, pressure and volume monitoring devices including automatic shut-off switches and electronic data recorders, and requiring that brine haulers install electronic transponders to ensure monitoring of all shipments.[307]

In addition, press reports from West Virginia also suggested a correlation between seismicity and disposal wells in that state.[308] Andrew Maykuth from the *Philadelphia Inquirer* reported on January 14, 2012 that the Columbia University team had been invited to Youngstown, Ohio in 2011 and they had installed four seismographs near the well in November.[309]

A new study from the USGS (not yet published but is due to be presented at a conference in April) has added to the discussion. The study reports that from 1970 to 2000, the midcontinent saw a six-fold increase in the number of seismic events with a magnitude greater than or equal to 3. From 1970 to 2000, the number of events with magnitude greater than or equal to 3 was 21 plus or minus 7.6 per year. From 2001 to 2008, that rate increased to 29 plus or minus 3.5 per year. In 2009, 2010 and 2011, there were 50, 87 and 135 such events, respectively.[310] Between 2001 and 2008 the rate increased by 1.4 times the rate of these events between 1970 and 2000. In 2009, the rate again increased 1.7 times. In 2010, the rate again increased 1.7 times over the previous year. 2011 saw a 1.5 times increase over 2010. That rate from 2001 to 2011 has increased more than six-fold in 10 years.

The USGS team concludes that the seismicity rate changes are almost certainly manmade.[311] The study authors say that it is not yet clear how the earthquake rates are related to oil and gas production, but other researchers have linked earthquakes to wastewater well injection. One of

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[305] Fountain, H. "Quakes add to rumblings over hydraulic fracturing." Raleigh *News and Observer*, December 13, 2011.
[306] Niquette, M. "Ohio quake spurs action on 5 wells, won't stop oil and gas work." *Bloomburg News*, January 4, 2012.
[307] LoParo, Carlo. "Ohio's New Rules for Brine Disposal Among Nation's Toughest." Ohio Department of Natural Resources. March 9, 2012. Retrieved March 12, 2012 from http://www.ohiodnr.com/home_page/NewsReleases/tabid/18276/EntryId/2711/Ohios-New-Rules-for-Brine-Disposal-Among-Nations-Toughest.aspx.
[308] Steelhammer, R. "Small earthquake rattles Braxton near quake cluster recorded in 2010." *West Virginia Gazette*, January 11, 2012.
[309] Maykuth, A. "Quakes focus scrutiny on fracking." Raleigh *News and Observer*, January 14, 2012.
[310] Ellsworth, W.L., Hickman, S.H., Lleons, A.L., McGarr, A., Michael, A.J. and Rubinstein, J.L. "Are seismicity rate changes in the midcontinent natural or manmade?" Abstract, Seismological Society of America, April 18, 2012.
[311] Ibid.

the study authors said "he is confident that fracking is not responsible for the earthquake trends his study found."[312]

Many oil and gas fields are located in areas where tectonics – faulting , folding and mountain building– has occurred, such as Arkansas, Texas, Oklahoma, Ohio and Colorado. The Wabash Valley between Illinois and Indiana is a rift system and the northern extension of the New Madrid Seismic Zone. Increases in seismicity near Guy, Ark., which is on the southern end of the New Madrid Seismic Zone, have been correlated to deep well disposal.

As to the possibility of triggering a larger earthquake in the Triassic basins from natural gas production, it would depend on two factors. The first has to do with the orientation of faults, since orientation affects the ability of the fault to accumulate stress. Faults orientated either low angle or high angle to the present stress field cannot accumulate stress. Faults with strikes at 30 to 60 degrees to the present stress field can do so. With additional research, the exact orientation of all known faults in the basins could be identified to determine which are capable of generating earthquakes and their expected moment magnitudes.

The second factor is the practice of deep well disposal. The Triassic rocks have low permeability, which is why hydraulic fracturing is required to create the pathways to release the natural gas. Low permeability rocks are poorly suited for deep well disposal of wastewater from hydraulic fracturing. In the Triassic Basin, the rocks at depth do not have the interconnectivity necessary to store large volumes of fluid.

Oil and gas exploration activities near some critical infrastructure, such as federal dams, require coordination between private industry, state agencies and federal agencies. In addition, while the Aug. 23, 2011, Mineral, Va., earthquake had only a moment magnitude of 5.8, the U.S. Nuclear Regulatory Commission required the North Anna nuclear power station to be shut down for 81 days following this event before the Agency authorized a restart of the power station. Damage to the facility was slight, but changes were made to the ways plant personnel respond to such an event.

Summary

The process of hydraulic fracturing causes microseismic events or very small earthquakes that do not pose a threat to the environment or human health or safety. Most reports of significantly increased seismicity have occurred in regions where disposal wells are operated and related to underground injection of waste rather than hydraulic fracturing. Only a small fraction of those operations are inducing seismicity. Limiting injection volumes, decreasing pressure, and distributing the waste between more disposal wells have been shown to reduce and even eliminate induced seismicity, while reusing and recycling of wastewater can reduce the need for other waste management options. Based on these considerations, we recommend that the state maintain its prohibition on underground injection of wastewater due to North Carolina's unsuitable geology for wastewater injection and seismic risk.

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[312] The Associated Press. "Oil and gas production linked to spike in Midwest earthquakes: study." *The New York Daily News*. April 7, 2012. Retrieved April 16, 2012 from http://articles.nydailynews.com/2012-04-07/news/31306045_1_magnitude-quakes-sharp-jolt.

L. Disposal, storage and transportation of hazardous and non-hazardous solid waste

Under both state and federal law, there is normally a clear dividing line in the management of hazardous and non-hazardous solid waste. With respect to oil and gas drilling wastes, the picture is much less clear because wastes that may be classified as hazardous waste are not regulated as hazardous waste under the primary federal law.

As defined in the federal Resource Conservation and Recovery Act (RCRA), hazardous waste is a solid waste that may

> "(i) Cause, or significantly contribute to, an increase in mortality or an increase in serious irreversible, or incapacitating reversible illness; or
>
> (ii) Pose a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported, disposed of or otherwise managed."[313]

A solid waste is a hazardous waste if it is not excluded from regulation as a hazardous waste and meets any of the following conditions:

- It exhibits any of the characteristics of a hazardous waste (ignitable, corrosive, reactive or toxic).
- It has been named as a hazardous waste and appears on one of four lists in the regulations.
- It is a mixture containing a listed waste and a non-hazardous waste; or
- It is a waste derived from the treatment, storage or disposal of a listed hazardous waste.

Federal hazardous waste regulations include the following exclusion: "The following solid wastes are not hazardous wastes: Drilling fluids, produced waters, and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy."[314] EPA guidance "does not preclude these wastes from control under state regulations, under the less stringent RCRA Subtitle D solid waste regulations, or under other federal regulations."[315]

In some instances, drilling fluids and liquids used to fracture the shale contain additives that are hazardous materials. Spills or releases of chemicals used in exploration and production can occur as a result of tank ruptures, equipment or surface impoundment failures, overfills, vandalism, vehicle accidents or improper operations. In the instance of a chemical spill, the cleanup could produce wastes that have a hazardous component (such as contaminated soils)

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[313] 40 CFR 261.10(a)
[314] 40 CFR 261.4(b)(5)
[315] U.S. Environmental Protection Agency, Exemption of Oil and Gas Exploration and Production Wastes from Federal Hazardous Waste Regulations, EPA530-K-01-004, www.epa.gov/osw/nonhaz/industrial/special/oil/oil-gas.pdf

that would not be considered exempt from RCRA and may require handling as a hazardous waste.

While chemical additives used in drilling may still be regulated as hazardous wastes, drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy are exempt under the EPA regulatory decision cited above. Although large quantities of fluids are needed during exploration and production of natural gas, industry reports indicate that much of this fluid can be recycled. Section 4C discusses the alternatives for disposal of any remaining process wastewater. This section will address disposal of other wastes and the particular challenge of handling waste streams that do not neatly fit into the standard categories of hazardous and non-hazardous waste.

For the state of North Carolina to appropriately regulate exploration and production waste, the state must know the chemical makeup of all fluids used during hydraulic fracturing. The composition of fracturing fluids varies from company to company; the geology of the area being drilled may also require adjustments in the fracturing formula. Natural gas companies performing hydraulic fracturing activities are not required under federal law to identify the chemical composition of the hydraulic fracturing fluid. This information is necessary in order to determine how to treat and dispose of any fluid waste from the hydraulic fracturing process.

In 2009, the New York State Department of Environmental Conservation (NYSDEC) produced a document that lists 12 classes of additives used in the shale fracturing process. A “sample fracture fluid composition by weight” from this report is presented in Table 4-13.

Table 4-13. Sample of Hydraulic Fracturing Fluid Composition by Weight

Additive Class	Fluid Composition by Weight
Acid	0.110%
Breaker	0.010%
Bactericide/Biocide	0.001%
Clay Stabilizer/Controller	0.050%
Corrosion Inhibitor	0.001%
Crosslinker	0.010%
Friction Reducer	0.080%
Gelling Agent	0.050%
Iron Control	0.004%
Scale Inhibitor	0.040%
Surfactant	0.080%
pH Adjusting Agent	0.010%

This NYSDEC report discusses how each product within the 12 classes of additives may be made up of one or more chemical constituents. The report presents “a list of chemical constituents and their Chemical Abstract Service (CAS) numbers that have been extracted from complete produce chemical compositional information and Material Safety Data Sheets (MSDS) 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." This list contains more than 250 compounds and classes of compounds (i.e. Petroleum Distillates, Aliphatic Acids, Aromatic Hydrocarbons). Only a handful of these chemicals would be used in a single well, but the list demonstrates the variety of chemicals that may be utilized.

It is important to know the types of chemicals being used both to ensure appropriate disposal of any waste and to be prepared for emergency response. A number of states have required disclosure of compounds used in fracturing fluids. In some states, the driller only has to disclose the information to the state regulatory agency. Other states also require public disclosure. In either case, any proprietary information would need to be protected.

Oil and gas producing states have generally developed specific standards for handling exploration and production wastes that may have the characteristics of hazardous wastes, but are not regulated under RCRA because of the federal exemption. Standards for exploration and production wastes typically fall somewhere between RCRA hazardous waste rules and the less stringent standards applied to typical industrial and household waste. North Carolina does not have standards that specifically address disposal of or transportation of exploration and production waste.

North Carolina solid waste regulations, at 15A NCAC 13B .0105, make the collector responsible for the satisfactory collection and transportation of all solid waste to a permitted disposal site or facility. Solid wastes may be sent only to a site or facility permitted to receive the particular type of waste. Solid waste rules also set standards for vehicles or containers used for the collection and transportation of garbage, or refuse containing garbage. The current standards were intended to address the risk of leakage, spills and avoidance of nuisance conditions (such as insect breeding). Spilled material must be picked up immediately by the solid waste collector and returned to the vehicle or container and the area shall be properly cleaned.

The existing state rules were not developed for waste materials that may have the characteristics of hazardous waste.

- DENR recommends additional study of regulations in other oil and gas producing states, including requirements for chemical characterization of waste, transportation tracking and reporting requirements, hauler certification and manifest standards, to identify the kind of additional regulations needed to ensure the safe handling, transportation, storage and disposal of exploration and production waste.

State law defines "solid waste" to include the non-oil components of exploration and production such as the drilling muds and cuttings. [316] Under state rules, solid wastes that are not RCRA hazardous wastes may go into an industrial landfill designed and constructed for that particular waste or to a municipal solid waste (MSW) landfill.

Since North Carolina statutes and rules have not been written to address these particular types of wastes, existing state rules would allow disposal of all RCRA-exempt exploration and production wastes (other than oils and liquid hydrocarbons) in a MSW landfill. North Carolina

[316] The definition excludes oils and other liquid hydrocarbons.

has strong standards for design and construction of both industrial and MSW landfills, but those standards were not developed for disposal of hazardous waste. As a result, disposal of exploration and production wastes, which may be classified as hazardous absent federal exemption, may present some risks that MSW landfills have not have been designed to manage. The nature of these wastes may also cause landfill operators to refuse to accept the waste even if state law continues to allow disposal in an MSW landfill. A landfill operator can exclude wastes that would otherwise be allowed for disposal; wastes that are difficult to handle or perceived to pose an unusual risk may be turned away.

Solid waste types known to be generated in the shale gas industry

The majority of waste produced in the shale gas industry is liquid. Liquids are not allowed in landfills. Types of industrial solid waste include:

- Drilling muds that pass the paint filter test
- Drill cuttings unless the drill cuttings are radioactive regulated waste
- Waste water residuals
- Produced sand
- Spent filters and filter media that do not contain oil
- Soils contaminated due to spill or leaks, but not hazardous waste
- Pipe rust, scale and other deposits

Available types of solid waste disposal in North Carolina

Hazardous waste disposal facilities

Currently there are no commercial hazardous waste disposal facilities in North Carolina. The Division of Waste Management oversees the operation of 10 commercial hazardous waste management facilities that store and treat hazardous waste. Commercial hazardous waste facilities are permitted to store hazardous waste from offsite sources and could be permitted to accept wastes generated by shale gas exploration and production. Although the facilities currently operating in North Carolina are not disposal facilities, the facilities are responsible for ensuring that the waste is disposed properly.

Industrial landfills

Industrial landfills receive specific types of industrial waste. At present, there are only three types of industrial landfills in North Carolina: coal combustion residuals produced by the electric power industry; battery-related wastes; and wastewater sludge and boiler ash from the paper industry. Twelve out of 13 industrial landfills are located at the facility where the waste is generated; the landfill space is used by the permitted landfill owner or operator, who is usually also the waste generator. The one exception is a Halifax County facility that accepts coal combustion residuals from small regional power companies.

Industrial landfills – siting, construction and operation regulatory requirements
Industrial landfills are sited, constructed and operated according to North Carolina sanitary landfill regulations 15A NCAC 13B .0503 and .0504. These regulations require that industrial landfills must have a design that requires a leachate collection system, a closure cap system and a composite liner system consisting of two components: the upper component is a flexible membrane (30 ml minimum) and the lower component is a two-foot (minimum) compacted soil with a hydraulic conductivity of no more that 1×10^{-7} cm/sec. An applicant may also prove through modeling that an alternative landfill design can meet state groundwater standards at the compliance boundary. Industrial landfill modeling must include hydrogeologic characteristics of the facility and surrounding lands, the climatic factors of the area, and the volume and physical and chemical characteristics of the leachate.

- **Recommendation:** Exploration and production waste should only be allowed in a landfill with a liner and leachate system that meets the standard for a MSW landfill.

  Modeling of the exploration and production waste within the current regulations would only evaluate and provide a design for one chemical makeup of waste. This type of model would not account for the variety of chemicals used in gas production and would make it difficult for the industry to evolve and vary the industrial process (and therefore the waste stream). The industry's desire to protect information about the types of chemicals used in the fracturing fluids as proprietary would also make it difficult to rely on modeling as the basis for an alternative landfill design.

In addition to preventing leachate from contaminating groundwater at the compliance boundary, state rules establish siting and design criteria to prevent landfill impacts on floodplains, threatened and endangered species, archaeological or historic sites, parks, recreational or scenic areas, and state nature or historic preserves. Other standards address potential explosion hazards and impacts to surface waters.

Landfill sites must also maintain buffers between the disposal areas and certain features:

- A 50-foot minimum buffer between all property lines and disposal areas
- A 500-foot minimum buffer between private dwellings and wells and disposal areas
- A 50-foot minimum buffer between streams and rivers and disposal areas

Municipal solid waste landfills
In North Carolina presently there are 40 landfills that are allowed to take nonhazardous solid waste. MSW landfills are constructed with leachate collection systems and one of three regulatory liners, or an alternative liner design with equivalent protection from leakage and with modeled groundwater protection. These municipal solid waste landfills are sited, constructed and operated under N.C.G.S. 130A-295 and regulations 15A NCAC 13B .1601 through .1637. The siting criteria are more stringent than the industrial landfill siting criteria.

MSW landfills are allowed to take all types of non-hazardous solid wastes with the exception of petroleum wastes. Other possible options are available for handling petroleum contaminated soils from spills or leaks associated with exploration and production, such as management by land application through the Division of Waste Management - Underground Storage Tank Section or use as fuel in brick kilns.

Possible waste-handling problems associated with the shale gas industry

Naturally occurring radioactive materials (NORM) - NORM has been shown to be present within shale formations of the Triassic Basins. Section I of this report describes the types of wastes that may include radiation. It is possible that accumulation of waste with undetectable levels of radiation will cumulatively cause detectible radiation in a landfill. Levels of radiation would have to be closely monitored at the landfill to ensure safe levels are maintained. Detection of radiation would require the landfill to cease accepting the cuttings and possibly move existing radioactive waste. That determination would be made by the Radiation Protection Section of the North Carolina Department of Health and Human Services. Waste from oil and gas exploration and production activities would thereafter have to be taken to a low-level radioactive disposal site.

Occurrence of NORM because of the prevalence of radioactivity in some rock formations has been a cause of concern at MSW landfills. Drill cuttings from water supply wells have sometimes caused the radioactivity meter at a landfill to react. (More often, radioactivity detected at a landfill has originated from medical waste.) Operational plans for permitted landfills include procedures for responding to radiation detection at the landfill. The initial action taken involves the facility and/or the DWM contacting the Department of Health and Human Services - Radiation Protection Section, in order to effectively and safely isolate and dispose of radioactive waste.

- **Recommendation:** Industrial and MSW landfill's operational plans should be required to include radiation monitoring at the working face of the landfill when exploration and production waste is being accepted.

Hazardous wastes - Solid Waste landfills cannot accept RCRA hazardous waste. MSW landfills are responsible for screening the waste received to exclude any hazardous waste from disposal. As noted above, exploration and production wastes present some special challenges. Some types of chemical-contaminated wastes and waste materials that are not exclusive to the oil and gas industry but used in the manufacturing of natural gas (such as battery or paint waste) continue to be classified as RCRA hazardous waste and cannot be disposed of in a MSW landfill. As noted above, many oil and gas wastes (such as drill cuttings) are exempt from RCRA regulation as a hazardous waste. North Carolina law would not currently prohibit disposal of those wastes in a MSW landfill.

- The state should consider the need for additional standards, including a requirement for waste determinations and rules excluding certain exploration and production wastes from MSW landfills. Hazardous waste regulations and rules adopted in other oil and gas states should be studied to develop appropriate regulations.

Difficult to handle wastes - Landfill operators are not required to unconditionally accept all wastes that could be lawfully disposed of at the landfill. The nature of the exploration and production industrial wastes may cause the landfill operator to turn the waste away, even if it is not hazardous. Shale cuttings are the consistency of very fine clay or silt; the cuttings may be difficult to handle and may also cause the landfill to experience operational problems. Large slugs of shale cuttings, when placed in an MSW landfill, could create a layer of relatively impermeable waste. This layer may create a “perching” effect in which the leachate (liquid that has percolated through or drained from the landfill waste) stays on top of the cuttings. If the leachate exerts pressure on the side slopes of the landfill, a failure of the side slopes may result in contaminants leaving the landfill.

Industrial landfills do not at this time receive solid waste disposal fees. If the shale gas industry chooses to site a landfill in North Carolina, it is recommended that fees be assessed for this type of waste at commercial industrial landfills. It is not recommended that the tax be assessed at industrial landfills that are located at the facility that generates the waste.

Possible compromise of landfill components – There has not been research on the possible interaction between chemicals used in industrial processes (such as natural gas production) and other wastes in MSW landfills and effects on the liner or leachate components. The possibility of the chemical solutions compromising the landfill integrity must be thoroughly assessed before these exploration and production wastes are allowed into existing or new landfills. DENR should undertake at the least a literature review to determine if design or operational changes are needed for this particular waste stream.

Recycling of waste

It is not likely that the solid wastes from the exploration and production of natural gas in North Carolina will be suitable for beneficial land application, roadspreading or other recycling uses. DENR should assist the industry, however, in identifying those wastes and byproducts that are suitable for recycling purposes. Additional resources within DENR will be needed for personnel with industry specific expertise.