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Hydraulic fracturing: a look at efficiency in the Haynesville Shale and the environmental effects of fracking

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HYDRAULIC FRACTURING: A LOOK AT EFFICIENCY IN THE HAYNESVILLE SHALE AND THE ENVIRONMENTAL EFFECTS OF FRACKING

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ABSTRACT

Hydraulic fracturing has become a hot topic in America's growing, domestic, oil and natural industry. This new technology has provided an economic way to extract resources from tight oil and gas shale formations found deep underground, but this new way of drilling does not come without environmental and human health effects. Among these health effects are water usage, water quality, and air quality. In this paper, data from Frac Focus.org was used to get the average amount of water used per well, and the average amount of chemicals, and what those chemicals are, for each well in the Haynesville Shale. An extensive literature review was used to get average air emission data from drilling and hydraulic fracturing. Data from the Louisiana Department of Natural Resources' SONRIS was used to find average drilling statistics associated with Haynesville Shale wells and used to determine drilling and hydraulic fracturing efficiency. These parameters were then used estimate air emissions, water usage, and chemical use in the Haynesville Shale. It was found that on average an unconventional well in the Haynesville Shale used 6.5 million gallons of water. The top three chemicals used in fracking fluid were found to be: Hydrochloric Acid, Phenol, and Quaternary Ammonia Salts, used at an average concentration of 0.21%, 0.086%, and 0.02%, respectively. Air emissions from unconventional drilling processes were estimated for NOx, CO, VOC, PM, SOx, CO2, and CH4. Overall, the drilling process in the shale was found to emit the most amount of emissions, except for CH_4 where fracturing emitted the most. Lastly, using the drilling parameters and water use calculations, evidence was shown that learning by doing was taking play in the Haynesville Shale and that efficiency, in some aspects of the well development activities, was being achieved.

CHAPTER 1: OVERVIEW OF UNCONVENTIONAL OIL AND GAS DEVELOPMENT AND LEARNING BY DOING

1.1. Overview of Unconventional Resources and Hydraulic Fracturing

Hydrocarbons are typically located in geologic formations that are commonly classified as being "conventional" or "unconventional" in nature. Conventional hydrocarbons are ones typically extracted from soft, relatively porous and permeable rock formations from vertically-drilled wells of varying depths. Unconventional hydrocarbons, however, come from a variety of differing geologic formations that includes various sands and shales. Unconventional hydrocarbon development from shale plays also tend to utilize a form of high pressure, artificial stimulation, known as hydraulic fracturing which utilizes water, chemicals, and various propants to extract natural gas from shale formations found thousands of feet below earth's surface (Comen, 2012). This additional form of stimulation is necessary since these unconventional resources are typically located in formations where the porosity is smaller, or tighter, than those found in conventional reservoirs.

Shale plays, as well as the use of hydraulic fracturing methods, do not represent a new set of hydrocarbon resources of extraction methods. Both were known with some degree of detail going back to at least the 1940s. These resources went undeveloped for a number of decades since they were considered too deep and too "tight" to be economically recoverable. Today, most new wells drilled in the United States are horizontal and use a method of hydraulic fracturing to retrieve the oil and gas down below. As of 2009, 50 percent of all U.S. natural gas production originated from unconventional reservoirs and is expected to increase to 60 percent by 2035 (EPA, 2004).

An unconventional well goes through a number of different steps prior to commercial development. Selecting the appropriate site is the first step in the life of an unconventional well. While the geologic characteristics of the anticipated drilling site are the most important, there are a number of other location-specific factors that must be considered including water availability, road access, supporting public infrastructure, proximity to gathering lines and processing, to name a few. The selected site also needs to have enough acreage to support access roads, the wellhead(s), tanks and pits for water and waste storage, and other materials (EPA, 2004).

The second step in the process is associated with site/well development and construction. A typical unconventional shale well utilizes a horizontal drilling technique that starts off with a traditional vertical segment that can vary from 8,000 to 16,000 feet in depth; and then transitions to a horizontal segment that runs from between 4,000 to 6,000 feet in length. The horizontal component adds more exposure to the hydrocarbon formation, which will allow for greater hydrocarbon recovery. Horizontal drilling leads to a considerable land-use advantage since one well is utilized to cover a much larger hydrocarbon resource base through the horizontal spans what is referred to as the well "laterals" (EPA, 2004).

As the well is drilled, well casing is inserted and cemented into place to secure the well, maintain is integrity, and to prevent the leaching of materials from the well segments into the surrounding subsurface. The drilling process itself utilizes a considerable amount of mud (water or oil based liquid) that is used to lubricate and clean the drill bit, drill collars, and drill pipe. All mud used during the drilling process is retrieved and either treated, recycled or disposed of. (EPA, 2004).

Hydraulic fracturing begins once the well is drilled. The hydraulic fracturing process utilizes millions of gallons of fresh water every day. Water is often pumped from a nearby source and

stored on site for future use over a fracturing process that usually spans 30 days. Several chemicals are added to the water to create the fracturing mixture. These chemicals, also referred to as fracturing "fluids," change according to the site but some fluids can include: hydrochloric acid, ethylene glycol, ammonium persulfate, citric acid, and even diesel, benzene, and arsenic (Coman, 2012). Also, a proping agent, usually coated silica (sand), is added to the fracturing fluid solution. The purpose of the chemicals and sand is to decrease pipe corrosion, minimize friction, and keep the fractures open (Loris, 2012). The solution is mixed at a 90:9:1 ratio of water: sand: chemicals, respectively (Coman, 2012). This solution is then injected down into the well at extremely high pressures that forces the shale formation to crack, allowing the sand to maneuver into the cracks and keep them open, releasing the natural gas back to the surface. Anywhere from between 15 percent to 80 percent of the fracturing fluid is retrieved, treated, reused or stored after its use (Coman, 2012).

Once the hydraulic fracturing process is complete, the well is either brought into service or properly plugged to await the installation of supporting production infrastructure such as gathering lines, treatment and/or processing facilities. This should be done by using a surface plug and a plug at the base of the lowermost USDW present in the formation. The plugs are used to prevent the natural gas, and any leftover solution, from entering the formation and/or water column.

1.2. Overview of the Haynesville Shale

The Haynesville region is considered a major shale play in the United States and is located primarily in northwest Louisiana and northeast Texas. The region was developed extensively in the early 1900s utilizing conventional drilling techniques. It is only over the past several years, primarily since 2007, that the Haynesville region has become a more utilized shale play (DOE,

2013). Geologically, the Haynesville Shale was formed from deposits dating back to about 150 million years ago during the Upper Jurassic age. The region was once covered by water, and as the water receded shale began to form and sediments were deposited. As subsequent layers were formed, the sediments were compacted to a great pressure. The natural gas formed within these sediments as a result of the depositions of the organic material from the sediments and the immense heat and pressure that they were under (Environ, 2013).

The natural gas within the Haynesville Shale is about two miles below the Earth's surface and has an estimated gas potential of technically recoverable resources of 251 trillion cubic feet or "TCF" (Geology.com, 2013). The Haynesville shale has an average thickness of between 200-300 feet and encompasses about 9,000 square miles of Louisiana and Texas (Mauck, 2013). The six major Parishes in Louisiana for the Haynesville Shale are Caddo, Bienville, Bossier, DeSoto, Red River, and Webster Parishes, along with a few other Parishes, will be the primary focus of this study.

The rock characteristic varies throughout the Haynesville shale and is generally broken down into three geological classifications from north to south: the "Field;" the "Sand;" and the "Zone" formations. The Northern part of the shale is the original Haynesville Field area which is primarily sandstone, the Haynesville Formation (Sand) grades into shale in the middle portion of the shale, and the Haynesville Shale (Haynesville Zone) dominantly consists of shale in the Southern portion. The shale poses many challenges because of its low permeability and high porosity that may cause areas of over pressurized zones. The shale is also is considered extremely high pressured and has high temperatures, which can add more complications when drilling. These tough conditions make drilling in the Haynesville Shale very costly (Colwell, 2011).

The first shale well in Louisiana's Haynesville region was spudded on February 27, 2006 but was never actually completed. It was not until late 2007 and 2008 that the Haynesville Shale started really being actively drilled because of high natural gas prices (Mauck, 2013). Development in the Haynesville Shale started picking up speed in 2008 when 75 wells were completed and began production. The next year, well completion more than quadrupled, to 361 wells, and by 2010 there were an additional 692 wells completed, and 1,105 wells producing 2,261 bcf which was double production of that the previous year (Kaiser & Yu, 2013). Today, there are currently 2,262 producing wells in the Haynesville Shale Gas Play, 130 wells are pending completion, 28 are permitted wells with drilling in progress, and 53 are permitted but drilling has not yet begun; this makes for a total of 2,473 wells in the Haynesville Shale (LADNR, 2013).

1.3. Overview of the Environmental Issues Associated with Hydraulic Fracturing

Hydraulic fracturing helps to recover what was once unrecoverable resources but poses many environmental and human health effects. The process of fracking uses drills, chemicals, heavy equipment, water, and many other things that do not naturally belong in the area raising considerably environmental concerns, the most important of which are typically associated with water use and the potential for chemical/fluid migration into ground water aquifers. Air pollution is also an important environmental concern given the wide range of combustion and compression activities that occur at a typical unconventional drilling and production site. Other environmental factors such as quality of life around fracking sites, seismic activity, and health of the workers are important but not at the forefront of fracturing issues.

Water use for hydraulic fracturing is a concern because each time a well is fractured it uses approximately 5 million gallons of water which can be over 100 times that used for conventional

drilling. Equally problematic is the fact that water used for fracturing is usually not returned to the system (Korfmacher et al., 2013). Water contamination is an issue because various amounts of chemicals are used in the fracking fluid and injected down into the earth, many times passing a public drinking water aquifer. The concern is that the chemicals may migrate up to the aquifer and pollute the drinking water supply. And finally, air quality is an issue because of the chemicals used in fracturing fluid and methane released from the injection of the fluid. Another concern is the sand, used as a propant, increases the particulate matter in the air around a fracturing site, which can cause respiratory effects of those nearby. Chemical and methane releases are of concern because of their effect on human health and methane is a worse GHG than carbon (Korfmacher et al., 2013).

1.4. Overview of Learning by Doing

The root of the learning curve theory is that as workers complete a task over and over again, they become more efficient at that task. This theory has been studied since line production manufacturing started in the early 1990s with aircraft manufacturing (Nemet, 2006). The study of learning curves in a manufacturer can help identify where a plant needs to become more efficient, can explain cost reductions to a firm, and they can help predict when future cost reductions may arise, among many other things. Traditionally, learning curve analyses are associated with estimating cost efficiencies that can arise from repetitive production activities, but these methods can also be utilizes to examine non-economic measures of efficiency such as those associated with reduced manufacturing production durations as well as the reduction in pollution (emissions, water use) associated with repetitive production processes. The potential environmental impacts of learning effects are of particular interest for this analysis of the Haynesville Shale given (a) the generally repetitive nature of horizontal drilling and hydraulic

fracturing techniques and (b) the very large number of wells that have been drilled in this particular formation since 2007.

1.5. Statement of the Research Problem

This study will evaluate the drilling activities of the Haynesville Shale since its start in 2007 and utilize a predictive model of regional drilling activities that attempts to incorporate (a) the cumulative environmental impacts of Haynesville activity that includes total air emissions, water use, and a chemical composition analysis of fracturing fluids reported to have been used over the past six years and (2) account for the possible “learning by doing” effects that may have increased drilling efficiencies, and reduced overall environmental exposure, due to the repetitive nature of the drilling activities in the Haynesville region.

CHAPTER 2: ENVIRONMENTAL ISSUES ASSOCIATED WITH UNCONVENTIONAL OIL AND GAS ACTIVITIES

2.1. Overview

Earlier, it was noted that unconventional (shale) resources are not some form of newly-recognized hydrocarbon reservoir. These resources have been known and characterized as far back as the 1940s. Likewise, horizontal drilling techniques are not new and have been utilized as far back as 1929 (EPA, 2004). In fact, over the past 25 years, the number of natural gas wells has almost doubled, much due to the technological advances of horizontal drilling and hydraulic fracturing (EIA, 2012d). Lastly, hydraulic fracturing is also a relatively well-known form of artificial well stimulation that has been used as far back as the 1940s, particularly in areas of East Texas and South Louisiana (EPA, 2004).

However, there are a number of important distinctions between each of these past activities that generally arose independently of one another, versus the nature of unconventional activity that has emerged over the past decade. So, while horizontal drilling or hydraulic fracturing is not new, the combination of these techniques, as well as the fact that they comprise over 90 percent of all incremental U.S. drilling activity, is very new. Further, while unconventional resources are not new, the scope and magnitude of the current development is unprecedented. The combination of drilling/stimulation methods, at very large scope and scale, has, not unexpectedly, led way to a number of important environmental issues and concerns. Water use and water quality issues are likely the largest environmental issues that have attracted various stakeholders and governmental regulators' attention. Equally important are the air emission issues associated with the considerable combustion activities, as well as incidental methane releases, that occur at many shale drilling sites. There are a number of other environmental

issues that collectively, garnered additional public, and hence regulatory, concern. Each of these major areas are surveyed in the following sub-sections of this Chapter.

2.2. Water Use Issues

While water is typically used in a number of processes at any given drill site, it is a particularly important input for unconventional wells, the overwhelming majority of which are stimulated through the use of high-pressure water injection (hence, the term "hydraulic fracturing"). The Environmental Protection Agency ("EPA") defines hydraulic fracturing as the process of creating fractures in the rock formation where the gas or oil is contained, to stimulate the flow of those hydrocarbons (EPA, 2013b). The fractures are created by pumping large volumes of water, sand, and chemicals into the shale formation at relatively high pressures[1]. After injection, formation pressures can cause fluids to move backwards up the wellbore in a process commonly referred to as "flowback" and can contain chemicals that were an original part of the fracturing fluids as well as those naturally-occurring in the formation. This flowback fluid is kept on site in either approved pits or tanks before being treated or disposed of using underground injection (EPA, 2013b).

The Haynesville Shale uses approximately 5.6 million gallons of fresh water per horizontal, hydraulically fractured well (Chesapeake Energy, 2012). In Louisiana, water used for fracking is currently withdrawn from surface water at various lakes, streams, rivers, or bayous. However, when fracturing was in its infancy in Louisiana, water utilized for fracturing was withdrawn from aquifers, a major one being the Carrizo-Wilcox aquifer (Lamy, 2012). The use of ground water for hydraulic fracturing led to considerable public concern, particularly for citizens in rural areas that draw most of their water from their own private wells. Ground water use concerns led to the

[1] Pumps can range from 9,000psi to upwards of 13,500psi like many of the Haynesville Shale wells. (Trieda & Poole & SPM, 2011)

Commissioner of Conservation at DNR to issue a water use advisory for Haynesville Shale operators. The advisory stated that well operators were to use other sources of water, primarily larger surface water resources located throughout the region (i.e. Red River, Toledo Bend Reservoir, etc.) (Lamy, 2012). Soon thereafter, the Louisiana Legislature passed Act 955 of 2010, to address the major withdrawal of surface water by non-riparian landowners. The Act states that "running water is a public thing owned by the State [Louisiana]…and especially ensuring that the State receives compensation for the sale of a public thing…" (Act 955). The Act also states that users must formally request use for water by the State, the State may put a price on the water at a per-gallon unit, and the industry instead of paying per-gallon, can show compensation by some other source (i.e. economic benefit) (LADNR, 2010).

Most of the surface water utilized in Louisiana hydraulic fracturing activities is drawn from the Red River, Toledo Bend Reservoir, or other lakes and Bayous in the Haynesville area. A small level of groundwater (around 19 percent), however, continues to be used for hydraulic fracturing activities in North Louisiana and is typically drawn from the regional aquifers such as the Red River Alluvial or the Carrizo-Wilcox (Mathis, 2010).

Recent studies estimate that the Haynesville shale play ranks as a moderate to high user of water relative to other unconventional plays across the U.S. A 2012 study conducted by Cooley and Donnelly estimates that overall hydraulic fracturing water use in the Haynesville region at around 5.5-6 million gallons per well (GPW) a level considerably higher than the median values estimated for the Barnett Shale (2.6 million GPW) and the Marcellus Shale (4.5 million GPW),[2] but considerably lower than the use estimated for the Eagle Ford area of South Texas (at 6.0 to 6.5 million GPW). Many other studies report various numbers for water used during the

[2] Reported by the authors from a study originally conducted by Beauduy, 2011.

hydraulic fracturing process showing its high variability and variation throughout each shale formation. [3]

Descriptive statistics associated with Haynesville water use activities can be taken from the hydraulic fracturing disclosure and education website, Frac Focus. The website is hosted by the Ground Water Protection Council (GWPC) and the Interstate Oil and Gas Compact Commission (IOGCC). Frac Focus is a voluntary program that operators can report the chemicals used in their fracturing fluid as well as total water used for the well.[4]

Table 2.1 shows Haynesville water use increasing over a four year period from 4.4 million GPW (2009) to 5.9 million GPW (2012) gallons per well. There are some issues, however, with these reported estimates. First, the share of total drilled wells reporting to each of these data sources, while increasing over time, vary in total and even in 2012 (the highest share reporting) is less than one percent. Second, the average water use per well implied by these data sources is far lower than those reported in the literature. Over time, these water use reports should improve since total water use will be required to be reported under recently-passed (October, 2011) chemical disclosure law (29 CFR 1910.1200).

Although public concern over hydraulic fracturing water use has been, and continues to be loud and vocal, the industry uses a relatively small amount of water, in total, relative to other large agricultural and industrial end-uses. Figure 2.1 shows, for instance, that power generation and chemical manufacturing are the two largest Louisiana water users (2010) at 1.3 trillion and 0.5 trillion gallons of water used per year, respectively (LADOTD, 2012). In fact, Louisiana

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[3] See, for instances, comparable studies estimating average water use per well by Chesapeake (2012) report 2.8 million GPW in the Barnette Shale and 5.6 million GPW in the Marcellus shale and 6 million GPW in the Eagle Ford Shale

[4] Frac Focus is a voluntary chemical registry. Many states now require operators to report to Frac Focus or their own state registry. The registry can be found at www.fracfocus.org

water use attributable to hydrofracturing activities is far lower than any other major source that includes agricultural irrigation, paper industry uses, and aquaculture.

Table 2.1: Reported Haynesville water use (Frac Focus)

Year	# of obs reported to Frac Focus	New wells drilled (yr)	Cumulative Active Wells in HS	% of new wells represented	Average water used per well reported (gal)	Total water used for new wells
2009	2	333	433	0.006	4,444,262	1,924,365,446
2010	24	672	1105	0.04	5,386,897	3,619,994,784
2011	494	784	1889	0.63	5,691,966	4,462,501,344
2012	364	373	2262	0.97	5,941,717	2,216,260,441

There is, however, an important difference between water use for hydro-fracturing activities and other uses. Other large water users utilize, then treat (if needed) and safely discharge their used water back into various surface water bodies often the ones from which the water was originally withdrawn. Water used for hydro-fracturing, however, once utilized, is typically disposed in an injection well in Louisiana and, thus, permanently removed from the overall regional water supply.

While Figure 2.1 suggest that hydro-fracturing activities use a relatively low amount of water, the use of water can be impactful to the community in the watershed. Cooley and Donnelly (2012), for instance, note that public concerns about fracturing water use tend to be local in nature, a fact often obscured by studies focused on impacts at the basin or overall state water supply level. Large volume withdrawals of surface water, for instance, can affect local hydrology, hydrodynamics, and can decrease the ability to dilute municipal and/or industrial wastewater discharge; which in Louisiana, is an important factor. The authors also found that unconventional developers are typically willing to pay for water supplies, even in instances when there are no readily-obvious aggregate water use/supply constraints, and often at levels higher

than the going market rate for water utilized in other sectors (i.e., power generation, agricultural use, etc.).

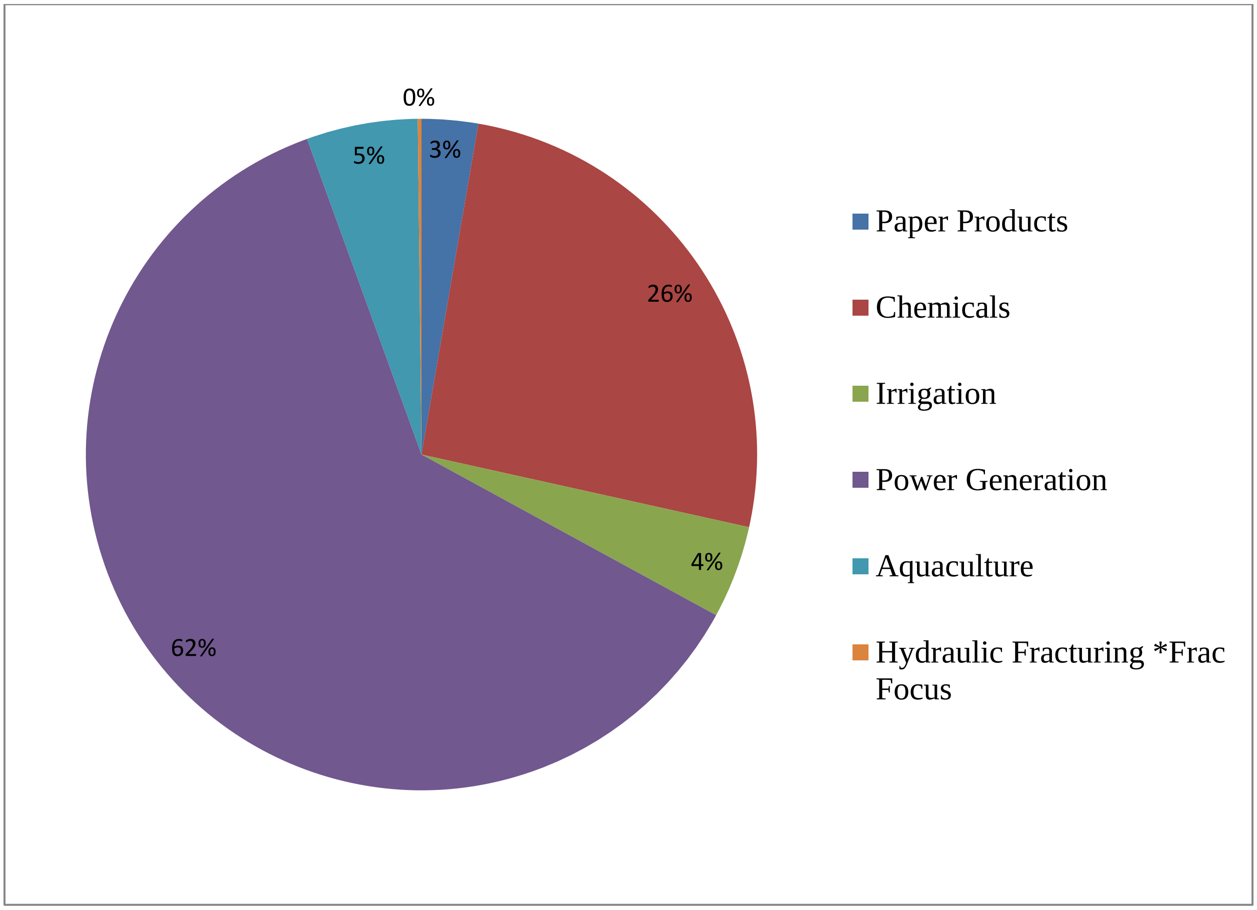

Figure 2.1: Water Use by Industry (2010)

2.3. <u>Water Quality and Chemical Use Issues</u>

Hydraulic fracturing and water use is generally not regulated by the federal government under most primary pieces of environmental legislation, with the one exception being associated with those drilling/fracturing activities occurring on federal lands. However, several pieces of federal legislation do allow federal oversight of certain discharge functions associated with hydro-fracturing activities. For instance, the Safe Drinking Water Act ("SDWA") does govern flow-back water/fluids and dictates which of these fluids can or cannot be injected underground (Reins, 2011). The Clean Water Act ("CWA") also governs certain flow-back discharges by

requiring operators to obtain a permit for these types of discharges into a surface water body (EPA, 2009). As a result, most operators are forced to either (a) send their wastewater discharges to EPA-approved water treatment facilities, or (b) re-injecting these discharges into underground storage reservoirs where such reservoirs are available. (Reins, 2011). Not all unconventional producing basins have access to underground waste disposal reservoirs, particularly those in Pennsylvania and Ohio and are, therefore, forced to treat hydro-fracturing discharges. Louisiana, however, has a large number of underground reservoirs that are eligible to handle and store hydro-fracturing discharges.

Ultimately, states, and not the federal government, regulate drilling processes as well as any water used in the drilling and well development process. For instance, the Louisiana Department of Natural Resources ("DNR"), as well as the Louisiana Department of Conservation ("DOC") regulates wastewater discharge and discharge/disposal activities from all oil and gas activities in the state including those in the Hayneville shale. To discharge any wastewater, the operator must have an approved LWDPS permit and cannot discharge directly into any fresh surface water body, vegetated area, soil, or intermittently exposed sediment surface area (Title 33, Part IX, Subpart 1). Most produced flowback water is injected into authorized disposal wells that are regulated under DNR. The drilling area must also have a "Spill Prevention and Control Plan" set in place (LDEQ, 2013).

The federal government, through the CWA and the EPA, does set drinking water standards for many chemicals that are used in fracturing fluid, but many chemicals are not included. Table 2.2 provides a list of commonly used chemicals and their maximum concentration limits (if regulated by the EPA).

Table 2.2: Chemicals used in fracturing fluid and their MCL's

Chemical Name	Max Concentration Limit (MCL) (mg/L)
Benzene	0.005
Ethylbenze	0.7
Toluene	1
Xylenes	10
Phenol	*EPA toxicity category ½ (highly to moderately toxic)
Hydrochloric Acid	*no MCL but 5ppm PEL
Quats	*EPA toxicity category 3 (slightly toxic)
Methane	*80 for trihalomethanes *no MCL for methane

The chemicals identified in Table 2.2, if mishandled, can create significant threats to surface and groundwater aquifers and one of the main public concerns associated with the use of these chemicals is their potential to somehow migrate upwards from their original fracturing depths, or penetrate well casings either through initial injection or fluid flow-back and migrate into aquifers. For instance, a conceptual analysis by Myers (2012), for the Marcellus Shale, identified numerous potential contaminant pathways from fracturing operations that include: (1) fracturing out of the shale formation; (2) connecting fractures in the shale to overlying bedrock; (3) displacement of fluids from shale to overburden (buoyancy); (4) advective transport (gradient); and (5) improperly abandoned wells. Myers posits that the thickness, and more importantly, the inherent shale properties affect fluid migration within the shale itself; however, the fractures created within the formation can lead to potential vertical movements. An equally important finding of Myers' work is the finding that (shale) fractures that are created within a relatively short distance to fault fracture zones, could lead to situations where contaminants could enter aquifers, and the surface, within ten years or less.

The potential for methane migration is an additional water quality issue that has risen over the past several years with extensive shale development and one that has garnered extensive

attention after the commercial release of the documentary film entitled “Gasland” which showed the ignition of methane embedded in the water flowing from a faucet in a home proximate to recent unconventional drilling/fracturing activity. The documentary has been widely criticized, particularly in its failure to inform viewers that in many places of the country, methane can naturally occur in aquifers and water supplies. In fact, to date, study results are mixed on whether hydro-fracturing or nature is responsible for methane entering a limited number of water supplies near unconventional drilling activity.

Jackson, et al. (2013), for instance, examine isotopic signatures to differentiate between thermogenic and biogenic methane sources in the Marcellus Shale where thermogenic methane is attributable to oil and gas activity, while biogenic methane is generated by microbes and is naturally-occurring. Jackson et al. found that homes less than one kilometer away from fracking sites measured six times higher methane concentrations in their water wells. Of the 141 drilling water wells examined, 82 percent were found to have thermogenic-based methane, with 12 of the 141 wells showing methane concentrations greater than 28 mg/L, the recommended level for immediate action deemed by the U.S. Department of Interior (“DOI”). The authors attributed faulty and/or inadequate steel casings or cement imperfections as the primary reasons for methane migration with hydraulic connectivity or abandoned (leaching) wells as the secondary concern for the pervasive methane migration.

Osborn et al. (2011), using a similar approach for the Marcellus region, found results similar to in the above-referenced Jackson, et al. (2013) study. The Osborn study examined 60 private water wells for methane and heavier hydrocarbons and found that 51 wells registered methane concentrations regardless of their distance from drilling/hydro-fracturing activity. Water wells located in proximity to unconventional oil and gas activity showed 17 times higher concentration

of methane than those wells located in non-active oil and gas areas. The average methane concentration for active area water wells in the Osborn study was 10 mg/L to 28 mg/L which is within the DOI-recommended action level for investigation and warning.

However, neither the Jackson et al. (2013) nor Osborn et al. (2011) study could conclude that chemicals from fracking fluid had migrated up to drinking water aquifers. As part of a Federal study of the hydraulic fracturing process, the Department of Energy (DOE) has been monitoring shale gas wells in Pennsylvania. Recently the DOE released information that "no evidence that chemicals from the natural gas drilling process moved up to contaminate drinking water aquifers" (Begos, 2013). The DOE study consisted of monitoring natural gas wells by using unique markers in the fracking fluid. The fracking fluid, with markers, was injected into wells at a depth of 8,000 feet. These markers were then searched for at a depth of 5,000 feet but were not detected, giving evidence that the fracking fluid did not migrate up close to drinking water aquifers (which usually are only a couple of hundred feet below the earth's surface). Nevertheless, these results should be taken with caution, and are still preliminary (Begos, 2013).

Surface spills of chemicals and other hazardous materials at unconventional drilling/hydro-fracturing locations are also of major concern in connection to ground or surface water contamination. Gross et al. (2013) analyzed publically-available data from the Colorado Oil & Gas Conservation Commission ("COGCC") on reported surface spills associated with hydraulic fracturing activities for a two-year period from 2010-2012. The authors found 77 spills (0.5 percent) were reported out of the 18,000 active wells in Weld County, Colorado (the county under study). A large number of these spills (81 percent or 62 spills) were analyzed for benzene, toluene, ethyl benzene, and xylenes ("BTEX") concentrations. At the time of the spills, average BTEX chemical concentrations were 2.2-times (benzene), 3.3-times (toluene), 1.8-times (ethyl

benzene), and 3.5-times (xylene) higher than the levels measured outside the excavation area for groundwater (Gross et al., 2013). Tank batteries and oil and gas production facilities are the largest source for these spills, and equipment failures were the known cause for 60 percent of the spills. Further, mean values of BTEX concentrations were observed to decrease from the first sampling date to the second, and so on; suggesting that remediation efforts by operators were effective at cleaning up the spill. All 77 spills were deemed "resolved" by later sampling.

2.3.1. Top 3 Chemicals used in Haynesville Fracking Fluid

Operators in the Haynesville Shale self-report a number of chemicals that are included in their drilling and fracturing fluids on the Frac Focus web portal. The top three chemicals used in hydro-fracturing operations in the Haynesville Shale include Hydrochloric Acid, Phenol, and Quaternary Ammonia Salts. These three chemicals are of major concern because of their average reported fluid concentration of 0.4 percent (hydrochloric acid), 0.18 percent (phenol), and 0.1 percent (quaternary ammonia salts), as well as their potential human and environmental health effects.

Hydrogen Chloride (Hydrochloric Acid) is used in fracking fluid to help dissolve minerals and initiate cracks in the formation given its strong corrosive properties. Hydrochloric Acid, however can be dangerous if it enters public drinking water supplies, and is known to lead to acute human health effects that can include gastro bleeding and respiratory irritation if inhaled. Chronic health effects associated with this chemical include a change in pulmonary functions, skin inflammation, nasal ulceration, and chronic inflammation of organs. The OSHA permissible exposure limit (PEL) is 5 ppm. Hydrogen chloride and hydrochloric acid are not classified as carcinogens (ATSDR, 2011).

Quaternary ammonia salts ("quats") are used in fracking fluid to eliminate bacteria in the water that, if left untreated, could result in the development of corrosive compounds (Frac Focus, 2013). The EPA groups quats in the registered hard surface disinfectants category. Acute human poisoning of quats is highly unlikely with low concentrations (EPA toxicity category 3, slightly toxic; over one ounce to one pint) but it very likely toxic in aquatic life. Chronic poisoning to human of less than or equal to 100 mg/man/year does not cause toxicity, but occupational asthma has developed with chronic exposure as well as irritant contact dermatitis (NHDOE, 2013).

Phenol is another disinfectant used in fracking fluid to great extent in the Haynesville Shale. It is another EPA registered hard surface disinfectants, and is more toxic than quats (category 1 or 2, highly to moderately toxic). Phenol is recognized as a carcinogen and can effect cardiovascular development, neurological system, reproductive system, respiratory system, skin, and sense organs. It is corrosive to the eyes and skin and can be absorbed through inhalation or through the skin. Phenol is also highly toxic to aquatic organisms and tends to bioaccumulate in the food chain (NHDOE, 2013).

2.4. Air Emission Issues

2.4.1. EPA's 6 Most Common Air Pollutants

The EPA has designated six common air pollutants and, in accordance with the Clean Air Act, sets National Ambient Air Quality Standards ("NAAQS") for each of these common air pollutants in order to protect human and environmental health. The six pollutants, most of which can be associated with unconventional drilling/hydro-fracturing activities, include Carbon Monoxide ("CO"), Nitrogen Dioxide ("NO_2"), Sulfur Dioxide ("SO_X"), Ozone ("O_3"), Particulate Matter ("PM"), and Lead ("Pb").

CO is a colorless and odorless gas that is emitted from many different combustion processes, but mainly from vehicles. In 1971 the EPA first set the air quality standard for CO at an 8 hour primary of 9 parts per million (“ppm”) and a 1 hour primary standard at 35 ppm. These numbers have yet to change since first set because no further evidence showed any reason to adjust them. Exposure to CO can reduce the oxygen carrying capacity of the blood (EPA, 2012a). If someone with heart disease is in an area of elevated CO they may experience myocardial ischemia (reduced oxygen to the heart) and chest pains. Also if someone is exercises in an area with elevated CO they may experience greater stress while working out. At extreme levels CO can cause death (EPA, 2012a).

NO_2 and nitrous oxides (“NO_X”), are highly reactive gasses. NO_2 is one of the two contributors to ground level ozone, the other being volatile organic compounds (“VOCs”). The EPA first set the standard for NO_2 in 1971 to an annual average level of 53 parts per billion (“ppb”). Although all NO_X forms raise air quality concerns, the EPA focuses on NO_2 because it is the indicator for the larger group of all nitrous oxides. The standards have not been changed since originally set in place but have been reviewed twice and concluded to be stringent enough for human standards. Short-term exposure to NO_2 can cause adverse respiratory effects including airway inflammation and increased stress of people with asthma. Roadways have been found to be two to three times higher in concentration of NO_2 than in areas away from roadways. NO_x can react with ammonia, moisture, and other compounds to form small particles that can penetrate sensitive parts of the lungs that can cause respiratory disease, or can aggravate existing heart disease (EPA, 2013c).

SO_2, arises from various combustion processes, particularly coal in power generation and industrial applications (i.e., furnaces and boilers) and is commonly referred to as an “acid rain”

pollutant given its negative impact on plant and vegetation. In Louisiana, the highest emitter for SO_2 is from industrial processes, the two highest being chemical manufacturing and petroleum refineries, throughout the state (EPA, 2013f).

Current standards for SO_2 are 75 ppb for 1 hour for primary and 500 ppb averaged over three hours at the secondary level, not to be exceeded more than once per year. These levels were changed from the original 1971 standards which set the primary SO_2 to a 24 hour standard at 140 ppb. The health effects for increased exposure to SO_2 are also related to respiratory functions. Exposure to elevated levels of SO_2 can be subject to more hospital visits and sicknesses, especially for young children, the elderly, or those who already suffer from asthma (EPA, 2013f).

O_3 is found both high up in the troposphere and down on ground level. O3 composition is the same up in the troposphere as that found at ground level but differs in the troposphere since O_3 serves as a protective barrier for the sun's UV rays while at ground level breathing ozone can lead to severe breathing irritation. O_3 differs from other pollutants since it is formed, not emitted, from the chemical reactions between other pollutants such as NO_X and VOCs which are primarily emitted by vehicles, and, to a lesser extent, industry. The current standard for Ozone is at 0.075ppm for 8 hours. (EPA, 2013a).

PM is a mixture of liquid droplets and solid particles found in the air. PM can consist of dust, dirt, or soot that you can see in the air with the naked eye and others are too small to see without a microscope. PM is broken up into two categories: (1) "inhalable coarse particles;" and (2) "fine particles." The coarse particles have a diameter that is larger than 2.5 micrometers and the fine particles have a diameter smaller than 2.5 micrometers. The highest emitters of PM (both coarse and fine) are from dust, e.g. construction sites, and fuel combustion. In Louisiana the highest

emitter of PM is from industrial process, mainly petroleum refineries, granaries, and chemical manufacturing plants. PM is a main contributor to haze and reduced visibility not only locally, but in neighboring regions. Elevated PM levels can cause serious respiratory problems. The current air quality standard for PM is 35 micrograms/m3 for coarse PM and 150 micrograms/m3 for fine, not to exceed a 24 hour period (EPA, 2013e).

Lead is naturally found in the environment and is also in many manufactured products. Lead emissions were historically generated by leaded motor vehicle fuels but have fallen considerably over the past thirty years given EPA regulations banning the use of lead in motor vehicles. The highest lead emitter today is still in the mobile category but it comes from aircrafts not cars. Today the air quality standard for lead is a rolling 3 month average, not to exceed 0.15 micrograms/m3. Unlike most of the other common air pollutants, lead can cause major damage to more than just the lungs and respiratory functions. Lead can negatively affect the nervous system, kidney functions, immune system, reproductive system, and the cardiovascular system. Lead can not only be inhaled from ore and metal processing plants or piston engine aircrafts, it can also commonly enter the body by being ingested, e.g. lead in drinking water or a young child eating lead based paint. Pb can have the greatest effect on children and their nervous system. It is persistent in the environment and can adversely affect ecosystems at point sources of lead (EPA, 2012c).

2.4.2. <u>Other Important Air Emissions: Methane</u>

Methane (“CH_4”) is not one of the top six common air pollutants but it is a source of concern for air quality because of its identity as a greenhouse gas (“GHG”). Methane is the second most prevalent GHG behind CO_2 even though it only makes up 9 percent of the total GHG emissions (EPA, 2013d) it is of more concern than CO_2. One pound of methane is equivalent to 20 lbs of

CO_2, making it a better trapper of radiation. Therefore its climate change potential is 20 times greater than that of CO_2. Methane is the primary component of natural gas, it also can be produced during the distillation of coal, and is a component of fire damps (harmful vapors produced during coal mining operations) (Encyclopedia Britannica, 2014). Natural gas and petroleum production emit the most CH_4 of the whole industry, followed by enteric fermentation of the agricultural industry. Methane is a valuable gas used for home heating and plant operations; it burns readily in the air to form CO_2 and H_2O. It is an important source of Hydrogen and other organic chemicals. Its byproducts are used for fertilizers, explosives, and even as a reinforcing agent for rubber tires on cars (Encyclopedia Britannica, 2014).

Of the six criteria pollutants, five have been associated with hydraulic fracturing operations: CO, NOx, SOx, O3, and PM, not Pb. Concentrations in and around fracking cites should always be monitored, so as not to exceed current standards.

2.4.3. Air quality associated with hydraulic fracturing

In hydraulic fracturing's early stages staggering concerns were mostly associate with water use and water quality. Today, environmentalists have changed their focus to that of air quality around fracturing sites. Unlike most conventional drilling and even coal, hydraulic fracturing is taking place in many people's backyards and near major cities. This gives rise to the concerns associated with hydraulic fracturing and air quality.

Many new studies have hit the scientific journal market recording that of air emissions near fracking sites. One of the most recent and thorough studies is that coming out of University of Texas at Austin where they conducted a study using 190 onshore natural gas sites in four different natural gas producing areas around the country (Allen et al., 2013). Methane emissions were tracked at the fracturing site and later compared to that of what the EPA estimated in the

2011 National Greenhouse Gas Inventory. Using the 190 sites that were monitored and then extrapolated to all fracturing wells in the US, Allen et al. estimated that 2,300 Gg of methane was being emitted from natural gas production annually. Conversely, the EPA estimated that 2,545 Gg of methane was being emitted annually Allen et al., 2013). The difference in the numbers can be explained by the difference in measurements for each hydraulic fracturing stage. For example, during the flowback stage (a process where the well is cleared of any remaining liquid and sand) the EPA assumed that all the methane would be leaving the wellhead and vented into the atmosphere at this time and that little or no methane was being captured and stored, whereas some operators capture the methane instead to venting it. Another big difference between the Allen et al. study and the EPA's inventory report, are the emissions associated with unloading (a process where liquid accumulation needs to be removed to allow the gas flow to continue) (Allen et al., 2013). The study reported an average of 5.8 Mg of methane emissions per well with an average of 5.9 unloading events happening per well. While the EPA reported an average that was 5 times higher than the study and had an average of 32.57 unloading events per well. One reason, the authors explained for this over estimation, is that the EPA assumed that the entire well bore volume was released and had continuous flow, which was not always the case for the study's wells (Allen et al., 2013). Overall, it should be noted that methane emissions around natural gas sites have dropped since 2009. This is probably due to the more stringent regulations and best practices enforced and voluntarily completed by many operators (Allen et al., 2013).

Another important study to mention in accordance to hydraulic fracturing and air quality is that done by McKenzie et al. (2012). This study took place in Garfield County, Colorado and evaluated the exposure to hydrocarbons for residents living less than half a mile away from a

fracturing site and compared it to the exposure of residents living more than half a mile away from fracturing sites. The team used air toxics data from the county spanning a time frame from January 2008 to November 2010 for short term exposures and also ongoing ambient air monitoring to estimate the subchronic and chronic exposures and health risks (McKenzie et al., 2012). They then used these measurements to create a hazardous index (HI) for the two different residents' distances and based on the subchronic and chronic exposures. Overall they found that residents living less than half a mile from fracturing sites were at higher risk for both chronic and subchronic exposures. This was mostly due to the detection of aliphatic hydrocarbons, trimethylbenzenes, benzene, and xylenes. They also reported a cancer risk for residents living greater than half a mile from fracturing sites to be 6 in a million and 10 in a million for residents living less than half a mile away. This was mostly due to the high detection of benzene, 1,3-butaiene, and ethylbenzene. Furthermore, they concluded that, though shorter term, the high emissions associated with the well completion period contributed most to the subchronic exposures.

Several other studies found a heightened presence of criteria air pollutants, VOCs, and methane (Colborn. et al, 2014, Rich et al., 2013, Roy et al., 2013). Colborn et al. (2012), Colorado study found that a high detection of VOC's and four chemicals that were found in every sample of their 48 sample stock. Those four chemicals were methane, ethane, propane, and toluene. For their detection of carbonyls, formaldehyde and acetaldehyde were present in every sample. They also reported that the highest chemical detection was during the first four month of drilling and during the fracturing process. This high level of emission detection during drilling coincides with McKenzie et al. and Allen et al. studies. Rich et al.'s (2014) Dallas-Fort Worth study identified methane and 101 other chemicals in the atmosphere around fracturing sites.

Twenty of their 101 chemicals were identified as HAPs, one of highest note being benzene, which was present in 38 of the 50 cites sampled. Methane values were reported at 2.7 ppmv which was consistent with the Colborn et al. study and also above background levels used in the study. Lastly, Roy et al.'s (2013), Marcellus Shale study reported NOx, PM 2.5, and VOCs in relation to different natural gas processing activities (well development, gas production, and midstream) based on the development of the shale. They concluded that drilling, hydraulic fracturing, trucks, completion venting, wellhead compressors, pneumatic devices, and gas processing and transmission fugitives are the major sources of NO_x and VOCs; $PM_{2.5}$ was found to not have a major effect on the shale as a whole. Tucks and drill rigs were found to have the most tons per well drilled of NO_x, 6.9 and 4.4 respectively. Well completions were found to high the highest emissions of VOCs, 3.8 tons/well drilled for dry wells and 21 tons/well drilled for wet wells. Well development as a whole had the highest emission of $PM_{2.5}$, 0.53 tons/well drilled. The findings of high air emissions, specifically NO_x, due to well development are consistent with previous studies mentioned and findings of high VOC emissions due to venting during completion is consistent with the Allen et al. (2013) study.

Significant levels of chemical concentrations found in the air around hydraulic fracturing cites across all literature surveyed are those for NO_x, VOC's, and methane. Though individually the detection for each individual chemical making up VOC's was under the permissible limit, together they can become very dangerous, and in presence of NO_x and sunlight, ground level ozone can form. Methane is another chemical to make note of because of its identity of the second most potent greenhouse gas. Below is Table 2.3 comparing many VOC's throughout the literature studied along with the OSHA permissible exposure limits and Table 2.4 comparing NO_x, PM, and VOC's between the Marcellus Shale study and Haynesville overview. Since Roy

et al.'s (2013) study reported in tons per well drilled, a conversion to tons/day was applied to the numbers. There was a reported 1,121 wells drilled in the Marcellus Shale in 2009 so the number reported for emissions was multiplied by the number of wells drilled and then divided by 365 to get the tons per day amount.

Table 2.3: VOC reports from 3 different studies and the OSHA reported air emissions limits

Pollutant	McKenzie et al Colorado	Colborn et al Colorado	Rich et al DFW	OSHA limits
Benzene	0.95 ppbv	0.5 ppbv	0.89 ppbv	1 ppm 8hr
Ethane	n/a	24.4 ppbv	2.24 ppmv	NO PEL
Ethylbenzene	0.17 ppbv	n/a	0.53 ppbv	100 ppm
Methane	n/a	2.5 ppmv	2.7 ppmv	1000 ppm*
n-Hexane	4 ppbv	0.9 ppbv	1.4 ppbv	500 ppm
n-Propylbenze	0.1 ppbv	n/a	1.4 ppbv	NO PEL
Toluene	1.8 ppbv	1.2 ppbv	n/a	200 ppm 8hr

*NIOSH PEL limit

Table 2.4: Comparison of NO_x and VOCs reported limits in the Haynesville and Marcellus Shales (from Roy et al., 2013 and Environ, 2013)

Source	NOx Marcellus Roy et al	NOx Haynesville Environ	VOCs Marcellus Roy et al	VOCs Haynesville Environ
Drill Rigs	13.5	5.1	1.5	0.28
Frac Pumps	6.8	0.6	0.77	0.09
Completion (dry)	n/a	n/a	11.7	1.6
Pneumatics (dry)	n/a	n/a	1.5	1.5
Compressor	3.3 tons/bcf	0.0064	3.1	0.0048

*All measurements in tons/day unless otherwise specified

It is also important to compare emissions of hydraulic fracturing with those of other industries. Below, Table 2.5 compares emissions from other industries and that of hydraulic fracturing (numbers taken from Environ, 2013). Industry source numbers taken from the National Emission Inventory completed by the EPA in 2011.

Table 2.5 shows that though, in most cases, hydraulic fracturing accounts for less air emissions than other source categories, it still emits a significant amount of air emissions. These numbers should be continued to be monitored and best management practices for drilling should be in place by the driller. Since these numbers were published, the EPA set a new air quality

standard that applies to the fracking process after the well is tapped. The EPA requires any operator to start using “green completions,” during this time in the drilling stage. This technology allows the operator to capture the released gas into tanks and transport them by pipeline. Since most of this initial release is usually methane, operators will be able to sell additional methane to the market, instead of flaring or venting it off. Unfortunately, drilling companies have until 2015 to comply with these new regulations (Groeger, 2012).

Table 2.5: Comparison of NOx, VOCs, and CO emissions from different industries.

Source	NOx tons/year	VOC tons/year	CO tons/year
Fuel Combustion electricity utility	48,343.9	1,286.6	65,085.9
Fuel Combustion Industrial	113,745.6	7,676.6	70,166.9
Fuel Combustion Other	4,336.9	1,190.8	7,397.1
Chemical & Allied Product MFG	12,920.6	13,395.8	15,008.4
Metals Processing	1,147	553.7	2,022.5
Petroleum & Related Industries	51,588.5	11,9742.5	58,353.7
Other Industrial Processes	8,558.9	18,581.1	8,462.5
Highway Vehicles	101,659.7	42,033.6	429,281.6
Hydraulic Fracturing	12,962	8,488	7,942

CHAPTER 3: THE APPLICATION OF LEARNING BY DOING IN THE ENERGY SECTOR

3.1. Overview of Traditional Learning by Doing

Learning by doing has been a commonly studied event since the early 1900s when Theodore Wright described the effects of learning on production costs in aircraft manufacturing. Since stream line production has been in place in the United States and around the world, learning curves have been studied and used as benchmarks to help managers decide where to invest money, change production, or anything else to improve cost efficiency. Two big categories in which the learning curve theory has been used in are: production and manufacturing products; and also renewable energy technologies, to help predict when they will become economically efficient to replace non-renewable energy technologies. The basics of the learning curve is knowing the cost per unit, the cost for the first unit produced, the cumulative production, the learning index (b), the progress ratio, and the learning rate. The progress ratio (PR) is the rate at which costs decline each time the cumulative output doubles and the learning rate (LR) is =1-PR. Thus, a firm would want a lower PR and a higher LR. The average LR is known to be 80 percent (Nemet, 2006 & Dutton and Thomas, 1984).

Though learning curves have been discovered and research for many years, much more has been attributed to 'learning' than what it was solely responsible for. Dutton and Thomas (1984) explored the causes underlying learning curves for firms from the present (1984) to dating back 50 years. They also came up with a differing idea that the learning rate was not a given constant; rather it should be treated as a dependent variable. They identified two types of learning: exogenous learning, information acquired from an outside source, and endogenous learning, information coming from within or direct-labor learning. Out of the 200 firms analyzed, Dutton

and Thomas found four causal categories; 1) effects of technology change, 2) Horndal (labor learning) effects, 3) local industry and firm characteristics, and 4) Scale effects. They also concluded that the 'b' parameter (progress rate) isn't necessarily fixed; it is more likely dependent on a firm's behavior or management in regards to the set of casual factors. This study showed that many characteristics may show up in the learning curve theory but only some of the characteristics may be attributed to learning.

In tune with Dutton and Thomas, Argote and Epple (1990) also established causal categories or factors that influenced the learning curve. Argote and Epple (1990) empirically studied the reasons for variation in organization or work group learning curves. They found that companies simply producing a different product do not always explain why learning rates might differ from another company, but also that there "is often more variation across organizations… producing the same product than within organization producing different products" (Argote and Epple, 1990). They found 5 factors that contribute to this variation in learning curves; 1) organizational forgetting, 2) employee turnover, 3) transfer of knowledge across products and across organizations, 4) incomplete transfer within organizations, and 5) economies of scale. They concluded that learning curves can be found in many organizations, but the rate at which the organization is learning can vary based on those five factors. This study shows that the learning curve is highly sensitive and can show many causes to cost reduction.

As the learning curve theory matured, researchers were able to further identify specifically what was influencing a particular firm's costs. Sinclair, Klepper, and Cohen (2000) analyzed a Fortune 500 company that produced specialty chemicals by batch process with the goal of pin pointing the sources of cost reduction in the manufacturing process, especially in relation to experience. From collecting data from production log sheets, the researchers discovered that

experience gained from producing more did not influence cost reduction; rather, R&D chemists in a lab identified cost reducing strategies. Though costs were inversely related to experience and cumulative output, the actual cost reduction was attributed to R&D. However, this shows that learning in some degree was attributed to cost reduction, just not in the classic sense of the learning curve theory. With more sophistication in manufacturing plants, different styles of learning are able to contribute to cost reduction.

3.2. Learning by Doing in the Renewable Energy Sector

The learning curve theory can not only be applicable to manufacturing processes but also used in the renewable energy sector. Learning curves can help us predict when a certain technology will become economically viable for the masses to use. The learning curve can also help managers and financial backers with the decisions of which technology to contribute more time and money to.

An early look at learning curves in the renewable energy sector came from R.M. Mackay and S.D. Probert. Mackay and Probert (1998) took an empirical look at Photovoltaic (PV) systems and wind turbine and assigned learning curve models to them. They hypothesized that the learning curves could help us which renewable technology has the greatest potential for cost reductions. They found that PV modules have decreased by a factor of 10 over the past 15 years and a factor of >50 since the early 1970s. Also, the MW power capability per unit has grown at a high rate. For wind turbines, Mackay and Probert found that the costs of medium sized free-standing turbines in the country side are the most efficient. They found that wind turbines had a PR of 85% while PV systems had a PR of 70-75%. Making PV the renewable energy technology the primary technology to contribute to since the wind turbines systems have a higher progress

ratio making the cost decrease lower. This study is a good example of how learning curves can help decision makers decide which technology to promote.

Learning curves don't have to be limited to a study of one company or a few, but can account for the whole world's learning. Junginger, Faaij, and Turkenburg (2005) looked at the price of wind farms throughout the world to develop a global experience curve. In turn this would help forecast the price of wind electricity and the curve should suggest a faster price reduction than previously thought. The researchers used wind parks/wind farms to create their experience curve rather than just the cost of making one wind turbine unit. Also, the cost for electricity was examined not just the cost per capacity. Junginger, et al. found that increasing the size and capacity of wind turbines has decreased the cost of them in the past decade. But they have found that the investment cost for wind turbines in the 600-900kW range are the most economical and efficient. The UK and Spain were the two countries with global wind parks that were examined. It was found that the Spanish have lower investment costs than the UK but a higher progress ratio of 85%, while the UK has a PR of 81%. According to Junginger, et al. the progress ratio (PR) is a parameter that expresses the rate at which costs decline each time the cumulative production doubles. Having a PR of 85% means the learning rate is 15%, so actually, Spain is learning at a slower rate than the UK. This is a good example for how we can use learning curves to predict when a technology will be ripe for the masses to use.

Once again, learning curves can take into account several variables from the whole world to all the little factors that go into production. Once the learning curve model can account for all these factors we are able to pin point what's driving costs down (or up) and make managerial decisions that are necessary. An example of this is when Gregory F Nemet (2006) conducted a study that sought to understand the drivers behind the technological change in Photovoltaics

(PV). He hypothesized that learning by doing has had an influence on reducing the costs of PV. The study identified many factors that could affect cost reduction (i.e. experience, learning, R&D and spillover effects) and included those directly in the calculation. Nemet looked at the average cost of the module, the module efficiency, the plant size, yield, poly-crystalline share, silicon cost, silicon consumption, and the wafer size. The results were that all seven of the factors explained less than 60% of the change in cost. When the time period was broken up into two, further relationships were observed. The first time period, 1975-1979, saw an increase in the need to PV units which allowed manufacturers to switch to a less costly process of production and allowed for standardization in production. In the second period, 1980-2001, plant size contributed 43% of the change in cost of PV units and efficiency accounted for 30%. Module efficiency and plant size are the two variables that explain the change in cost the most with the cost of silicon being the third factor. Nemet was able to identify the two most influential variables with a sophisticated learning curve model that will allow decision makers to see future barriers, technological change, and how much technical improvement is needed for a certain cost improvement.

3.3. Learning by Doing and Environmental Performance

There are not many studies that connect the process of learning by doing to a firm's environmental performance. The best example found was that of Lapre et al.'s "Behind the Learning Curve: Linking Learning Activities to Waste Reduction" (2000). In this paper, Lapre et al. takes the same stance as Dutton and Thomas (1984) that the learning rate should be treated as a dependent variable. In a factory setting, Lapre et al. looked at two different types of learning, conceptual and operational, and assigned values for each type of learning to each different quality improvement projects the firm was undertaking. The score came out into four different

categories: low conceptual, low operational (firefighting); low conceptual, high operational (artisan skills); high conceptual, low operational (nonvalidated theories); and high conceptual, high operational (operationally validated theories). Lapre et al. found that for successful Total Quality Management solutions that the learning rate needed both conceptual and operational learning to contribute. Lapre et al. found that waste decreased by 50% over the 7 years studied, but could only be explained by 25% of the quality improvement projects. However, the remaining 75% waste reduction was attributed to the transfer of local project results.

The learning curve theory has allowed decision makers to make more informed decisions about how to run more efficiently and cost effectively since its beginning. The learning curve theory has many applications both big and small, and direct with just one company or with thousands. The learning curve can be modeled in such a way that it can provide very detailed information that can give valuable information to decision makers and has been used in many forms of production.

CHAPTER 4: DATA AND METHODS

4.1. Data Collection

Data was collected from multiple sources and compiled to calculate efficiency, emissions, and water and chemical use for the drilling and hydraulic fracturing process. Louisiana Department of Natural Resources (LDNR) publishes an online database of all wells in the state called SONRIS (Strategic Online Natural Resources Information System) (LDNR, 2013). From here, data associated with each horizontal well drilled in the Haynesville Shale was extracted starting from the shale's initiation in 2007, and progressing to October 2013. For purposes of this research, the geographic scope of the Haynesville Shale is defined as the six major parishes located in northwestern Louisiana including: Caddo; Bossier; Sabine; De Soto; Red River; Bienville; and two minor parishes: Natchitoches and Webster. In addition, wells were sorted by SONRIS condition code 51 (indicating that the observed well is located in the Haynesville Shale formation) and condition codes 70 and 8, which indicate that the observed well is drilled horizontally.

Drilling parameters were compiled or calculated for each horizontally-drilled well that include: total monthly production; true vertical depth (TVD); measured depth (MD); lateral length(s); well status (active, inactive, etc.); as well as spud and completion dates.

Natural gas production statistics were collected solely for the purpose of determining (corroborating) that each of the observed wells was, in fact, actively producing. TVD is the reported total distance (length) of the drilled well bore and is used to estimate lateral lengths (or the individual horizontal sections) for each observed well. Measured depth, on the other hand, reports the estimated distance of the vertical section of the well. Thus, the difference between

TVD and measured depth gives an approximation of the lateral length, and number of stages associated with each lateral.

Fracturing stages are not directly reported by SONRIS and were estimated using a standard stage length as reported in Roy, et al. 2013 that is comprised of one stage per every 100 meters, or 328 feet of lateral length. Thus, an estimated lateral length (TVD less measured depth) is divided by 328, to get the calculated number of stages for each well.

Spud and completion dates were utilized in an attempt to estimate drilling duration. However, the difference between the two dates (completion date and spud date), particularly as they are reported in SONRIS, may include durations (and delays) that are not associated with drilling operations that can include waiting on various permit approvals, drilling rig movements, fracturing time, and other delays associated with the unusually high level of region-wide drilling activity during this period. Therefore, drilling duration was simulated using a reported range. The range was developed from many different sources that reported average drilling time. The range decided on for this paper was 30-90 days. See Table A.1 for all sources considered for drilling duration. Table 4.1 below, provides a summary of the annual descriptive statistics associated with the well characteristics data compiled, or estimated from the SONRIS database.

Water and chemical use data was collected from the online chemical disclosure registry, Frac Focus (fracfocus.org), for each year in which such information was available. Water and chemical use data was then matched to the horizontal well characteristics data, on a per observation basis, using API numbers that are reported in common for each database (i.e., Frac Focus and SONRIS). Not all wells drilled during the 2007-2013 time period reported water and chemical use to Frac Focus. In fact, reported coverage changes considerably over the time

period under investigation since this was the period in which operators were beginning to start participating in this voluntary disclosure process.

Table 4.1: Descriptive Statistics: Haynesville Well Characteristics

Year		Avg Prod (MCF)	Total Prod (BCF)	New Well Counts	Cumulative Total Active Well Counts	MD (feet)	TVD (feet)	Laterals	Stages
2007	Min	42,656				15,930	11,315	4,615	14
	Mean	49,341	10	1	1	15,930	11,315	4,615	14
	Max	56,027				15,930	11,315	4,615	14
2008	Min	3,181				14,550	10,987	3,025	9
	Mean	121,900	1,975	43	44	15,922	11,626	4,296	13
	Max	713,366				16,910	12,545	4,940	15
2009	Min	2				14,143	9,763	2,333	7
	Mean	166,276	38,576	333	377	16,255	11,782	4,473	14
	Max	1,175,714				18,135	13,701	5,706	17
2010	Min	147,519				11,830	9,000	11,830	2
	Mean	1	125,967	697	1,074	16,610	12,043	16,610	14
	Max	1,468,862				19,033	16,038	19,033	21
2011	Min	1				11,700	10,724	26	0
	Mean	118,680	211,452	810	1,884	16,728	11,998	4,731	14
	Max	750,131				19,088	15,300	6,513	20
2012	Min	1				13,831	9,899	850	0
	Mean	89,050	216,241	332	2,216	16,992	12,129	4,862	15
	Max	1,908,325				20,647	14,458	8,363	25
2013	Min	4				15,610	10,576	4,147	13
	Mean	62,779	107,207	90	2,306	16,843	11,974	4,869	15
	Max	1,562,141				19,687	12,686	7,386	23

Table 4.2 provides the descriptive statistics for the water use data, and compares the coverage of that data relative to the well characteristics data. For instance, in 2009, only 1 percent of all active wells reported water use to Frac Focus.[5] This reporting coverage increased in 2010 to 3 percent, to 61 percent in 2011, and 98 percent in 2012.

[5] A complete list of descriptive statistics for water use in the Haynesville Shale as reported by Frac Focus can be found in Table A.4.

Table 4.2: Descriptive Statistics: annual reported water use (Frac Focus)

Year	% represented	Average water used per well (gal)	Min water used per well (gal)	Max water used per well (gal)	Std water used per well (gal)
2009	1	4,444,262	4,372,788	4,515,735	101,079
2010	3	5,386,897	2,778,144	8,943,102	1,430,775
2011	61	5,691,966	478,513	13,022,982	1,697,489
2012	98	5,941,717	367,290	34,258,678	2,845,141

Table 4.3 provides comparable data for chemical use on an annual basis as reported to FracFocus. Again, reporting coverage issues for chemical use as similar to those discussed earlier operator water use. In addition, Frac Focus does not report chemical use in total volumes, but instead, reports chemical use in concentration, or percentage, terms.

Table 4.3: Descriptive Statistics: reported chemical concentrations (FracFocus)

Chemical	Year	% represented	Average Concentration (percent)	Min (percent)	Max (percent)	std. dev. (percent)
36 HCl	2010	0.29	.3897	.3897	.38.97	.
	2011	34.4	.2024	.2017	.2097	.028
	2012	8.1	.1305	.1299	.1331	.012
Phenol	2010	.	.	.	.	.
	2011	8.02	0.26	0.18	0.36	0.09
	2012	21.7	0.12	0.06	0.23	0.05
Quats	2010	0.29	0.55	0.55	0.55	.
	2011	7.5	0.006	0.0055	0.0062	0.0003
	2012	17.5	0.011	0.007	0.014	0.004

4.2. Estimating Air Emissions from Haynesville Drilling and Hydro-Fracturing Activities

Air emissions equations, similar to those presented by Roy et al. (2013) and Environ (2013), were utilized to generate well-specific air emissions. Air emission equations were developed for two specific set of activities: one for air emission associated with drilling activities and one for the air emissions associated with hydro-fracturing activities. In addition, two additional sets of

equations were developed designed to estimate air emissions associated with support activities associated with both drilling and hydro-fracturing: one for the air emissions associated with supporting heavy duty vehicular traffic and one for the air emissions associated with venting activities at well at the well completion time. Diesel-powered engines that are part of the drilling rig are the primary sources of drilling-related air emissions in the Haynesville region. The primary pollutants associated with these combustion activities are NO_x, CO, VOC, PM, SO_x, CO_2, and CH_4. Equation (1) estimates the typical air emissions associated with Haynesville drilling activities ($E_{(drilling)ip}$), for each well with reported information (i = 1,… n), across each pollutant type (p = NO_X, CO, PM).

$$E_{(drilling)ip} = EF_p * ((T_{drill} * 24) * HP * LF * \% \text{ on-time})/(907{,}185) \qquad (1)$$

Where: T_{drill} represents drilling time (or duration) in days; HP is the total drilling rig engine horsepower; EF_p is the emission factor, reported in grams per break horsepower-hour (g/bhp-hr), for each pollutant p; LF is the average load factor, or fraction, of total horsepower used, and % on-time is the time the drill rig was actually utilizing during the day (Roy et al. 2013). Emission factors for drilling were collected from various sources from the EPA that has been provided in greater detail in Table A.2. Lastly, the fixed denominator in equation (1) simply converts estimates from grams to tons.

The variables representing emission factors, horsepower, load factor, and percent on-time are treated as a range of fixed inputs, or assumptions, in the estimation process. A range of input values, rather than a specific point estimate, is utilized in this model since well-specific estimates are later generated using a Monte Carlo-based simulation approach. Specific values for the ranges for each assumption/input variable are taken from a variety of sources, but rely most

heavily on the work conducted by Roy, et.al. (2013) and Environ (2013). The specific values, ranges, and sources for these input assumptions/variables are detailed in Table A.3.

This research is unique since it uses a more accurate range for drilling duration. By simulating the drilling duration, variation in drilling time can be accounted for, rather than just using a single static drilling average for every well drilled. By using this range and modeling emissions off of this a range, a more accurate air emissions estimate is able to be produced.

As mentioned earlier, drilling duration was simulated using a Monte Carlo simulation and a range compiled from different sources. The minimum number of drilling days used was 30 and the maximum was 90 days. This allows for a wider, yet representative, range specific to that of the Haynesville Shale. Because the shale presents many challenges (i.e. depth, pressure, and temperature) the range of drilling days may be higher than that of other shale regions. Total estimated air emissions, for each well, and each pollutant type (NO_X, CO, PM, etc.) are generated using a Monte Carlo-based simulation approach. Well-specific estimates are generated from a randomly-selected sample for each fixed input variable identified in Equation (1). For instance, drilling times, were randomly-selected from a random sample of potential drilling durations, over a given range (see Table A.1). The randomly-selected drilling time value was pulled from a sample which itself was drawn from 10,000 simulations. This basic simulation approach was utilized throughout the analysis in generating well-specific air emissions, water, and chemical use estimates.

Air emissions associated with hydro-fracturing operations, like drilling, are typically associated with the use of engines. Fracturing-related emissions, however, are, mathematically, a function of the number of fracturing stages, rather than drilling durations: the greater the number of fracturing stages, the greater then number of emissions. Air emissions associated with

fracturing operations is provided in Equation (2) and adopted from Roy, et al. for each well (i) and each pollutant (p)

$$E_{(\text{fracturing})ip} = (EF_p * HP * LF * N_{\text{stages}})/907{,}185 \tag{2}$$

where EF_p is the emission factor (g/bhp-hr) from one pump engine for pollutant p, HP is the horsepower required for one fracturing stage, LF is the average load factor of the pump engine, and N_{stages} is the number of stages completed for one well. Emission factors, for each pollutant type, were taken from EPA sources on non-road combustion activities, consistent with Environ (2013), and Allen et al. (2013). The input variable for engine horsepower (HP) and engine load factor (LF) were taken from Environ (2013) given the shortage of reported information on fracturing-specific engine equipment and its utilization, and the fact that the Environ research is Haynesville-specific.

This research differs from the prior literature since it utilizes a well-specific estimate of the number of stages in the Haynesville region, rather than simulating this information from a fixed range of assumed inputs. As noted earlier, stages are calculated as the difference between the vertical and horizontal depth of the well and divided by 328 feet: the typical distance of a Haynesville hydro-fracturing stage.

Traffic emissions are another significant contributor of emissions to both the drilling and hydro-fracturing process. A tremendous number of heavy-duty trucks move back and forth to unconventional drilling sites to support site preparation activities, to move drill string and other drilling equipment, to move drilling wastes, and most importantly, to move silica, chemicals, and sometimes water to the drilling site to support hydro-fracturing activities. These heavy duty trucks release a significant amount of NO_x and CO. Equation (3) was adopted from Roy et al. (2013) for traffic-based emissions for each well (i) and each pollutant (p)

$$E_{(Traffic)ip} = (EF_p * L_{trip} * N_{trip})/907{,}185 \tag{3}$$

where EF_p is the emission factor of pollutant p, L_{trip} is the length (miles) of the trip, and N_{trip} is the number of vehicular trips. The emission factors of the heavy duty trucks were taken from EPA Office of Transportation and Air Quality (OTAQ). A range was applied from Environ (2013) for the length of trip and number of trips. A Monte Carlo simulation was completed to estimate the distribution of both factors.

Completion venting is the last part of the drilling process and is conducted in order to remove any debris, liquids, and inert gases used to stimulate natural gas production (Roy et al., 2013). This step can be a major source for VOC emissions, especially with "wet" gas, which is not the case in the Haynesville Shale is primarily comprised of "dry" natural gas (methane).[6] Equation (4) was adopted from Roy et al. (2013) to estimate emissions for completion venting for each well (i) for only one pollutant type (VOC):

$$E_{(Completion)i} = (\rho_{gas} * f_i * V * n)/907{,}185 \tag{4}$$

where ρ_{gas} is the mass density of the gas, f_i is the mass fraction of VOCs in the vented gas, V is the volume of gas vented per completion, and n is the number of wells completed. ρ_{gas}, f_i, and V were taken from Environ (2013) and used as constants. The number of wells completed each year was taken from the SONRIS data.

4.3. Estimating Water Use from Haynesville Drilling and Hydro-Fracturing Activities

Prior studies that attempt to assess (and inventory) basin-specific environmental footprints of unconventional oil and gas activities have tended to focus on primarily on air emissions associated with those activities. Few studies have attempted to construct a bottoms-up estimate

[6] "Wet"is a term used to describe natural gas that is comprised of a relatively higher percentage (share) of heavier hydrocarbons such as ethanes, butanes, propanes, pentanes, also referred to as "natural gas liquids" or "NGLs." "Dry" is a term used to describe natural gas production that is relatively devoid of a high degree of NGLs and is primarily comprised of methane.

of water use on an unconventional basin-specific basis. There are numerous studies examining water quality issues (see Jackson et al. 2013 and Osborn et al. 2011) but not many quantifying water use from the well level. This research is unique since it generates well-specific (bottoms up) estimates of water use that can be used to estimate local, regional and basin-specific impacts over time.

Total per well water use, for both drilling and hydro-fracturing activities, was developed using a two-step process. First, as noted earlier in Section 4.1, some well-specific water use statistics are available per voluntary operator reports to Frac Focus. Table 4.2 shows the descriptive statistics for these reporting wells and also shows that 819 (35.5 percent) of the 2,306 wells voluntarily reported their per well water use. Thus, the first step simply matches wells to reported water use, and employs those specifically-reported values for total water use estimation purposes.

Step two estimates water use for the remaining 1,487 active wells with no reported water use. Water use estimates are developed by examining the relationship between water use, and hydro-fracturing stages, from the set of wells with known usage, based upon the following relationship.

$$W_i = \alpha + \beta N_i + \varepsilon \tag{5}$$

Where W_i is estimated per well water use (from the sample of observed water use data) and N_i is the estimated number of laterals discussed earlier in Section 4.1, and β is the estimated water use per lateral parameter that will be used to estimate water use for those observations with non-reported water use information. The resulting regression equation estimates water use with a relatively high overall coefficient of correlation ($R^2 = 0.18$) and a water use parameter that is (a) within reasonably-expected bounds, (b) of the correct (positive) sign, and (c) statistically significant at the 95 percent confidence level. The estimated water use per stage parameter (β)

is 4.6 gallons per stage with an estimated standard error of 1.12; both statistics were used to formulate a rate of water use per stage, which in turn was utilized to simulate per well water use for the 1,487 wells with no reported data.

4.4. Estimating Chemical Use Concentrations from Haynesville Drilling and Hydro-Fracturing Activities

Chemical use compositions are also reported to Frac Focus and suffer from the same reporting deficiencies noted earlier for water use. Some 1,599 wells, out of 2,306 wells report their respective chemical compositions. Specifically-reported data is used in the instances where such information is available. However, there are some 707 wells that have not reported their chemical compositions and a two stage simulation based method was utilized for these non-reporting wells. In the first stage, the probability of the well using chemical i was determined from the known chemical use data. In the second stage, the concentration in the fracturing fluid of the chemical was simulated using the descriptive statistics from the known concentrations of chemical i. The distribution and resulting concentrations produced from the Monte Carlo simulation were then assigned to unknown wells randomly to complete the distribution. This was done for all three chemicals of concern, mentioned earlier; hydrochloric acid, phenol, and quats.

CHAPTER 5: RESULTS AND DISCUSSION

5.1. Well Development Air Emissions

Emissions were calculated for all wells drilled and completed in the Haynesville Shale from 2007 to October 2013. Emissions were calculated on a tons per well basis and a tons per year basis. When well specific data was available, it was used, otherwise simulation results were entered and estimations were developed. Emissions were then compared to that of other major industries in the State of Louisiana. The year 2011 was used for close analysis and comparisons because of the robust representation of well specific data, the amount of drilling in the shale that occurred in the year, and to give better comparisons to other major industries. Fracturing operating companies were then compared and grouped. The top three 'big' and bottom four 'small' companies were chosen based on number of wells drilled in the shale and consistent representation throughout the years. The top three companies chosen were Chesapeake Operating Inc., Encana Oil & Gas, and Exco Operating LP. The bottom four companies chosen were JW Operating Co., EOG Resources Inc., Samson Contour Energy E&P, and XTO Energy Inc.

5.1.1 Well Development Air Emissions: Estimated Emission Rates

Emissions were calculated for all wells drilled and completed in the Haynesville Shale from 2007 to October 2013. Below are Tables 5.1-5.3 showing emissions for each development activity on an average per well basis. Since completion venting was based on fixed numbers, each well was estimated to emit 0.00064 tons of VOC per well for every year. Estimated drilling emissions across all pollutants seem to decrease as years go on, and then increase for 2011 and fall again for 2012. The increase for 2011 is most likely due to the increased well activity, and a higher representation of both big and small companies who may or may not take careful environmental measures. Estimated fracturing emissions are shown to rise throughout the years.

The rise can be attributed to longer lateral length and increased number of stages, which is a main driver for emissions associated with fracturing. Estimated traffic emissions follow the same trend as wells development each year. As the number of wells spudded increases, the traffic emissions for that year increase as well. Emission reduction will be seen in this area as emission factors for heavy duty trucks decreases, and/or number of trips for each well decreases.

Table 5.1: Estimated drilling emissions (tons per well basis).

Drilling	NO_x	CO	VOC	PM	SO_x	CO_2	CH_4
2007	11.50	6.23	0.72	0.359	0.019	2.78	0.0017
2008	10.58	5.73	0.66	0.331	0.018	2.56	0.0016
2009	9.73	5.27	0.61	0.304	0.016	2.35	0.0014
2010	9.95	5.39	0.62	0.311	0.017	2.40	0.0015
2011	10.03	5.43	0.63	0.313	0.017	2.42	0.0015
2012	9.77	5.29	0.61	0.305	0.016	2.36	0.0014
2013	9.89	5.35	0.62	0.309	0.017	2.39	0.0015

Table 5.2: Estimated fracturing emissions (tons per well basis).

Fracking	NO_x	CO	VOC	PM	CH_4
2007	0.0620	0.0388	0.0101	0.0042	0.0038
2008	0.0574	0.0359	0.0093	0.0039	0.0035
2009	0.0600	0.0375	0.0097	0.0040	0.0037
2010	0.0616	0.0385	0.0100	0.0042	0.0038
2011	0.0632	0.0395	0.0103	0.0043	0.0039
2012	0.0646	0.0404	0.0105	0.0044	0.0039
2013	0.0654	0.0409	0.0106	0.0044	0.0040

Table 5.3: Estimated traffic emissions (tons per well basis).

Traffic	NO_x	CO	VOC	PM
2007	0.1194	0.0359	0.0069	0.0030
2008	0.1251	0.0376	0.0072	0.0031
2009	0.1258	0.0379	0.0072	0.0031
2010	0.1260	0.0379	0.0072	0.0031
2011	0.1270	0.0382	0.0073	0.0031
2012	0.1252	0.0377	0.0072	0.0031
2013	0.1248	0.0375	0.0072	0.0031

For a closer look at air emissions, investigations, and comparisons, 2011 estimates will be used. Tables provided below are based upon the results from 2011 only since (a) it was the most active year for drilling/well development activity and (b) the results are highly representative of those found for the overall sample, as stated previously. Table 5.4 shows the estimated emissions for each major pollutant (NOx, CO, VOC, PM, SOx, CO2, and CH4) for each major well development activity (drilling, fracturing, and support activities). Air emissions associated with drilling support activities are primarily restricted to traffic movements to and from the drilling site.

Table 5.4: Estimated emissions, well development activities (tons per well).

Activity	NO_x	CO	VOC	PM	SO_x	CO_2	CH_4
Drilling	10.03	5.432	0.63	0.313	0.017	2.42	0.001
Fracking	0.085	0.053	0.014	0.006	.	.	0.005
Traffic	0.127	0.038	0.007	0.003	.	.	.

Table 5.4 shows that drilling activities tend to lead to the higher emissions per well than other types of well development activities since (a) drilling activities span a much longer period of time and (b) drilling activities are more stable and consistent than certain support activities that are intermittent in nature. Drilling can also lead to methane releases that are unique to that particular type of activity.

5.1.2 Well Development Air Emissions: Estimated Total Emissions

Estimated drilling emissions were also calculated on a yearly basis. Below in Tables 5.5 to 5.8 and Figures 5.1 to 5.4 drilling, fracturing, traffic, and completion venting emissions are shown. Drilling emission totals seem to follow the same trend as spudded wells for each year, meaning that the more wells drilled in a year the more emissions there will be. This is consistent across all

pollutant types. The main driver behind drilling emissions is drilling time, as drilling time continues to decrease across years, though; drilling emissions can decrease, even though more wells may be drilled. Total estimated fracturing emissions peak in 2011 and then drop down considerably in 2012. Though, tons per well is increasing throughout all years for fracturing because of longer laterals and more stages, the total tons of emissions does not because the number of wells drilled in 2011 is considerably more than that drilled in 2012. Total estimated traffic emissions, as well as completion venting emissions, follow the same bell-like curve as that of fracturing and drilling, again, because of the decrease in well development activity in 2012. The emission that should be of note here is NO_x, because of its high level and its ability to mix with VOCs and sunlight to form ground level ozone.

Table: 5.5: Total estimated drilling emissions (tons per year).

Drilling	TPY NO_x	TPY CO	TPY VOC	TPY PM	TPY SO_x	TPY CO_2	TPY CH_4
2007	11.5	6.2	0.7	0.4	0.02	2.8	0.002
2008	455.1	246.5	28.4	14.2	0.8	110.0	0.1
2009	3239.5	1754.7	202.5	101.2	5.5	782.9	0.5
2010	6935.4	3756.7	433.5	216.7	11.7	1676.0	1.0
2011	8123.3	4400.1	507.7	253.9	13.7	1963.1	1.2
2012	3245.0	1757.7	202.8	101.4	5.5	784.2	0.5
2013	889.7	481.9	55.6	27.8	1.5	215.0	0.1

Table 5.6: Total estimated fracturing emissions (tons per year).

Fracking	TPY Nox	TPY CO	TPY VOC	TPY PM	TPY CH4
2007	0.062	0.039	0.010	0.004	0.004
2008	2.5	1.6	0.4	0.2	0.2
2009	20.5	12.8	3.3	1.4	1.3
2010	42.4	26.5	6.9	2.9	2.6
2011	51.0	31.9	8.3	3.4	3.1
2012	21.1	13.2	3.4	1.4	1.3
2013	5.8	3.6	0.9	0.4	0.4

Table 5.7: Total estimated traffic emissions (tons per year).

Traffic	TPY Nox	TPY CO	TPY VOC	TPY PM
2007	0.12	0.04	0.01	0.003
2008	5.38	1.62	0.31	0.13
2009	41.90	12.61	2.41	1.04
2010	87.79	26.42	5.05	2.18
2011	102.90	30.96	5.92	2.55
2012	41.57	12.51	2.39	1.03
2013	11.23	3.38	0.65	0.28

Table 5.8: Total estimated completion venting emissions (tons per year).

Completion	TPY VOC
2007	0.0006
2008	0.028
2009	0.215
2010	0.450
2011	0.522
2012	0.214
2013	0.058

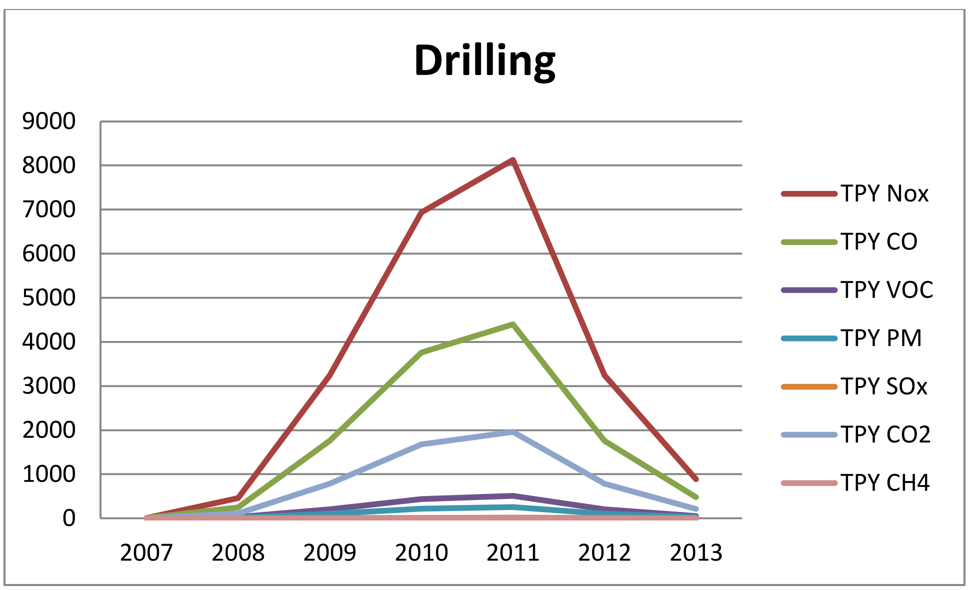

Figure 5.1: Drilling emissions trends (tons per year).

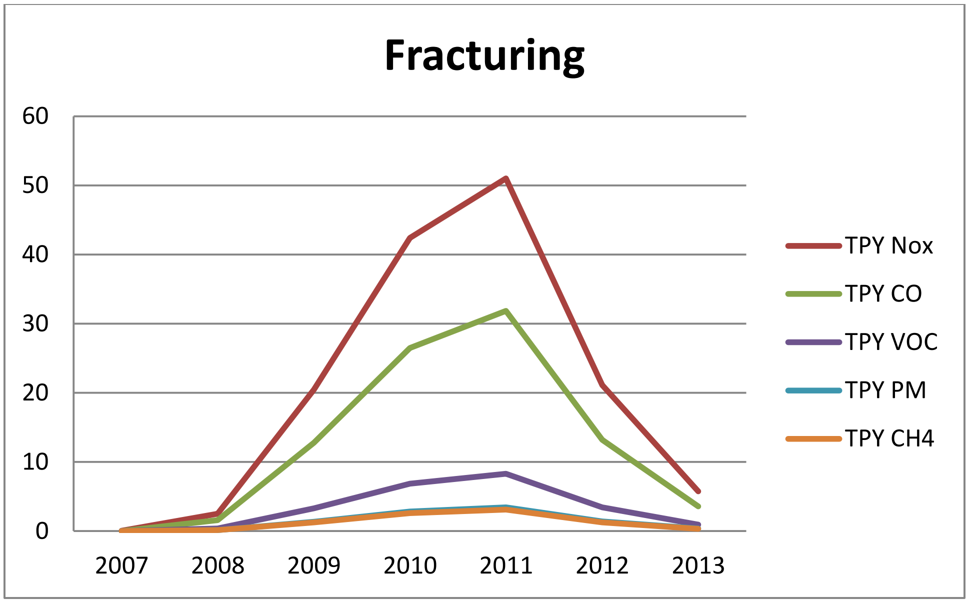

Figure 5.2: Fracturing emissions trends (tons per year).

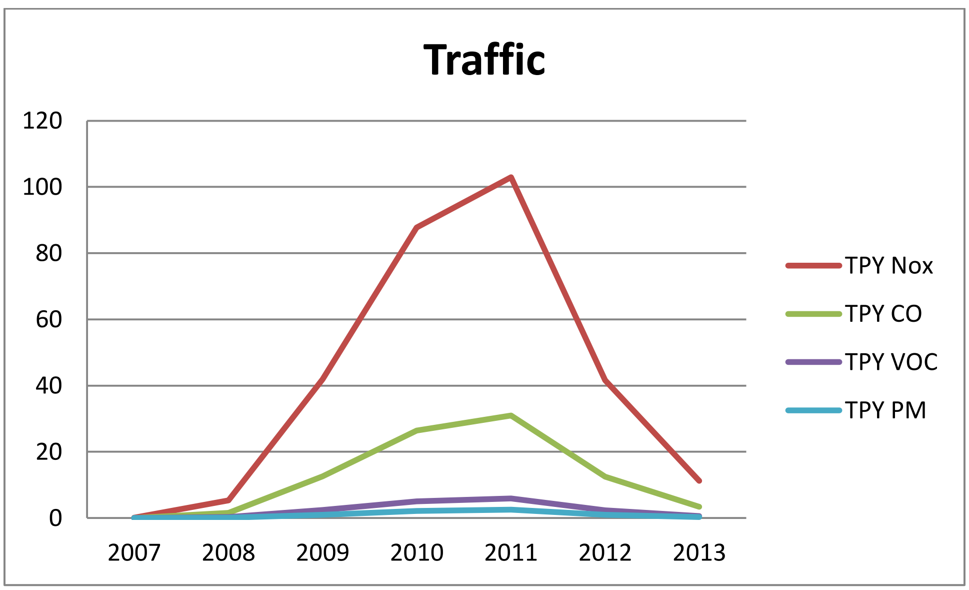

Figure 5.3: Traffic emissions trends (tons per year).

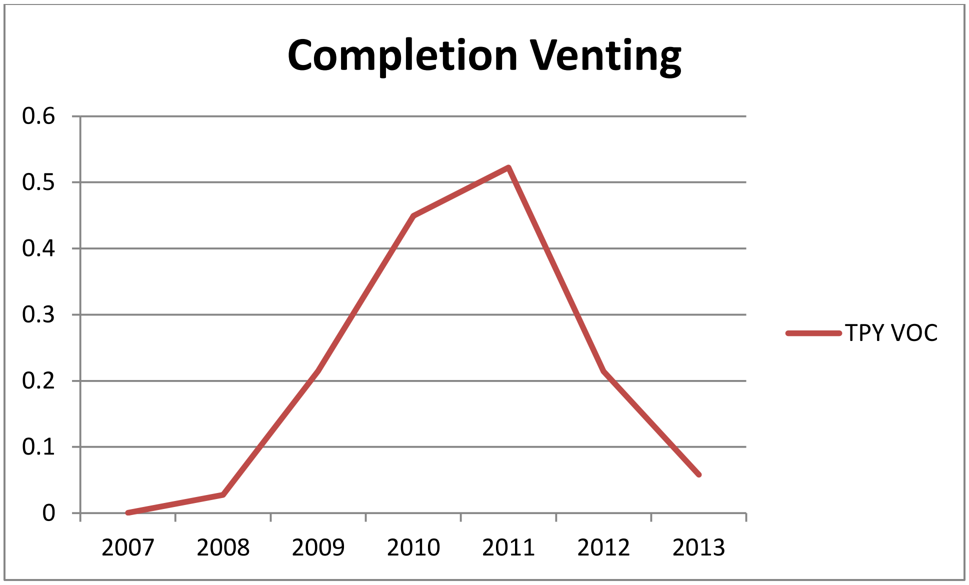

Figure 5.4: Completion venting emissions trends (tons per year).

5.1.3 Well Development Air Emissions: Comparative Analysis

Air emissions from development activities were also compared to other major industries in the State of Louisiana from the 2011 National Emissions Inventory completed by the EPA (EPA, 2011). Figures 5.5-5.9 show air emissions for the major industries plus fracturing development activities and how fracturing emissions measure up to that of other industries. Overall, fracturing emits considerably less than other industries in the state. Emissions of major concern should be that of NO_x emissions, especially during drilling activities, which is where 97 percent of the NO_x emissions in development activities come from. But fracturing development activities are only 4% of the biggest emitter (off highway). For CO emissions fracturing development are only 0.2% of the biggest emitter (miscellaneous). For PM emissions fracturing development only accounts for 0.1% of the biggest emitter (miscellaneous) and 0.6% of the second biggest emitter (Fuel Combustion Industrial). For all other air pollutants, fracturing is one of the lowest emitters compared to other major industries and accounts for less than half a percent of the biggest emitters.

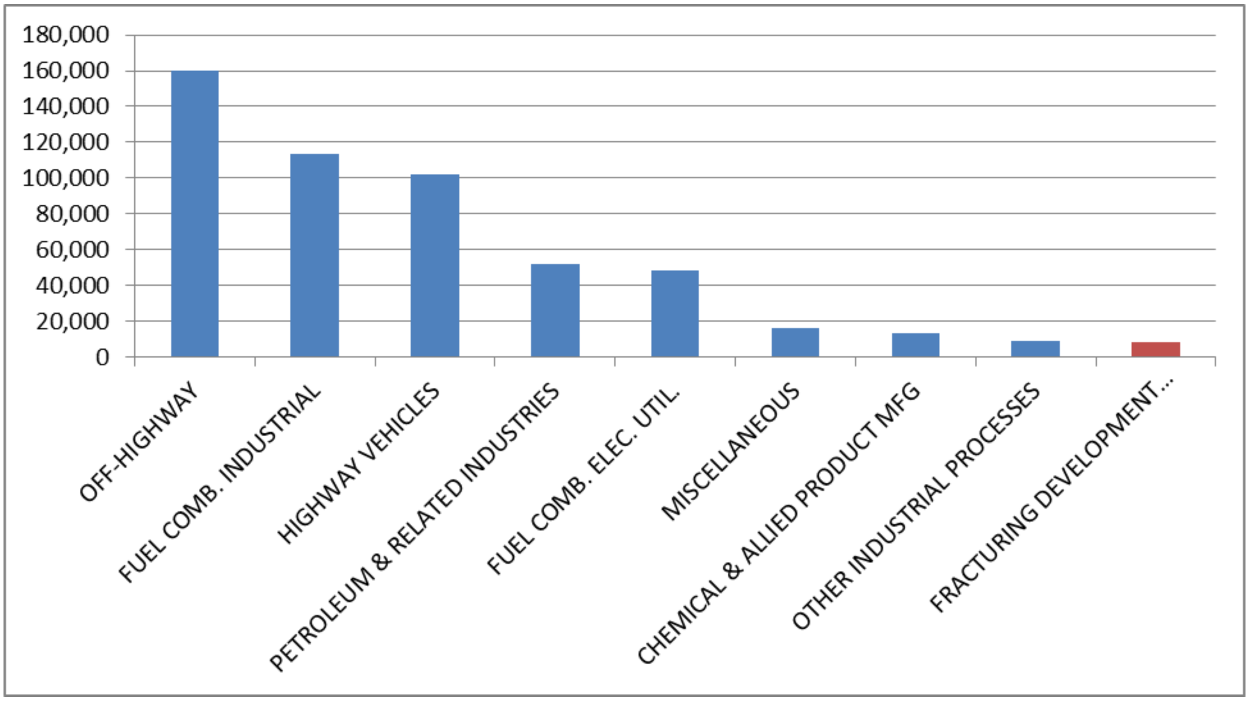

Figure 5.5: Comparison of NO_x emissions.

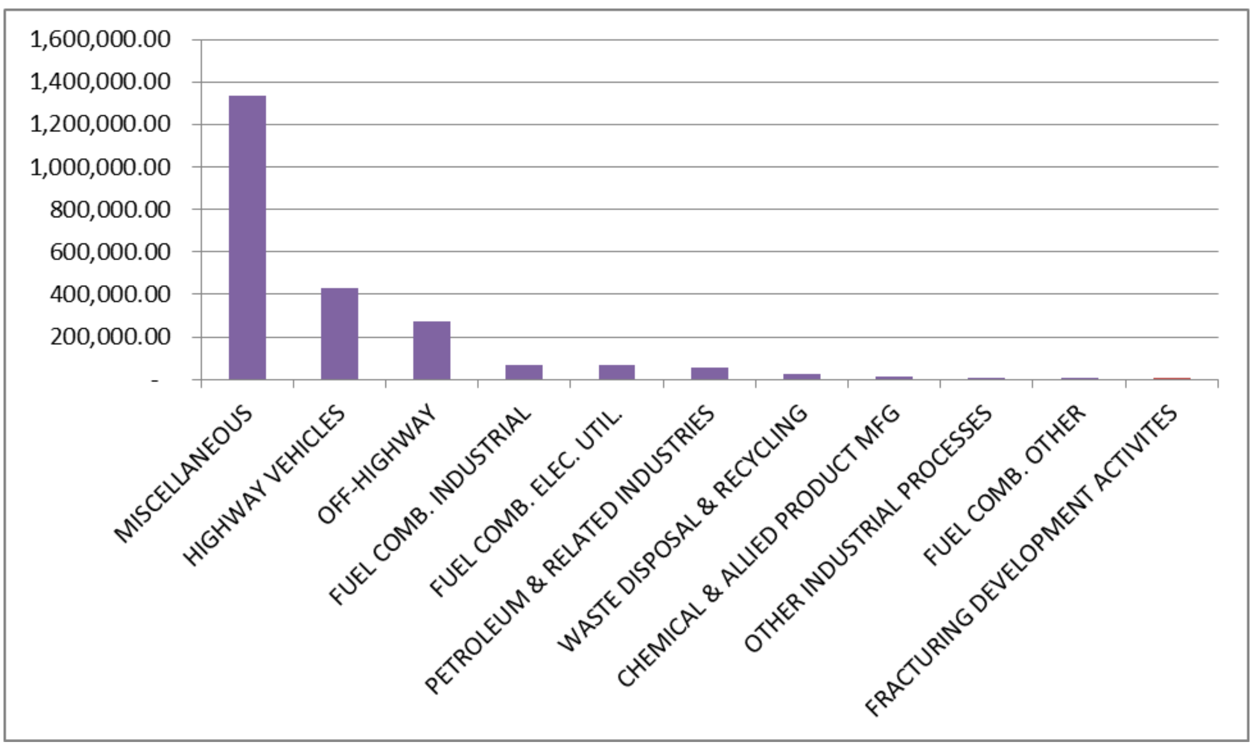

Figure 5.6: Comparison of CO emissions.

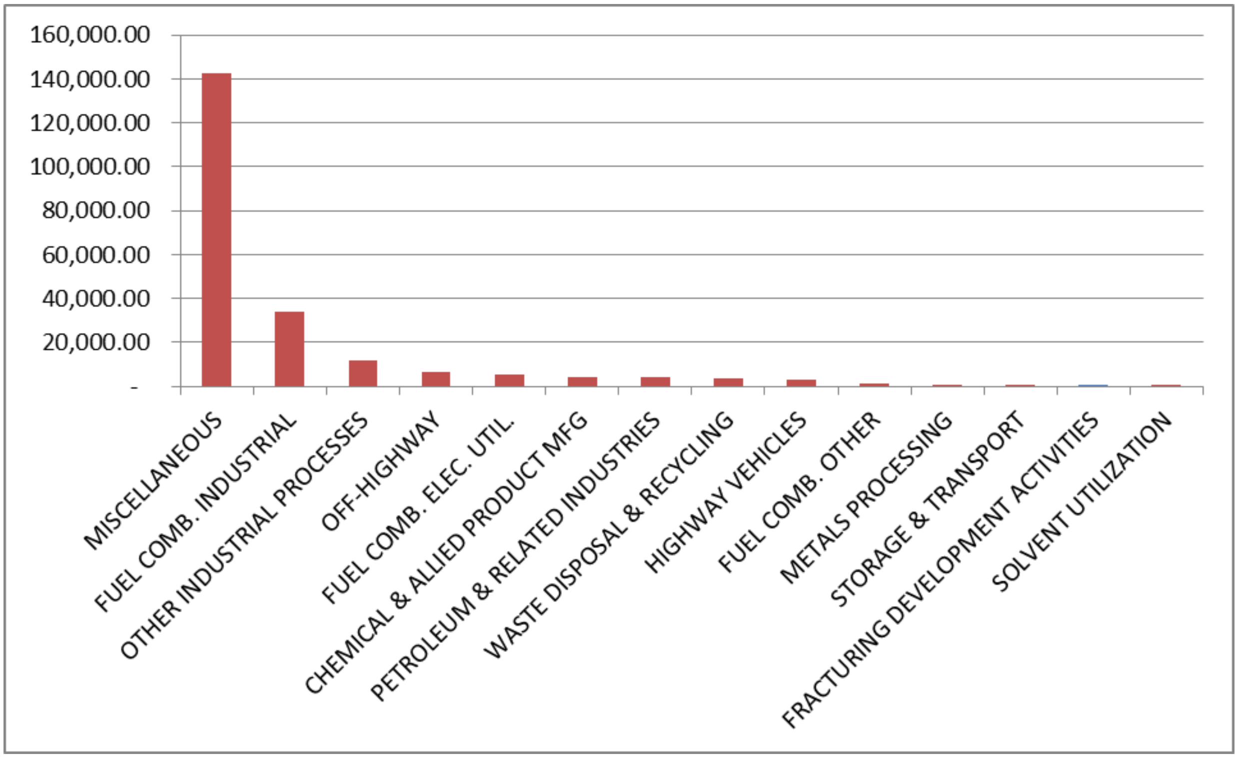

Figure 5.7: Comparison of PM emissions.

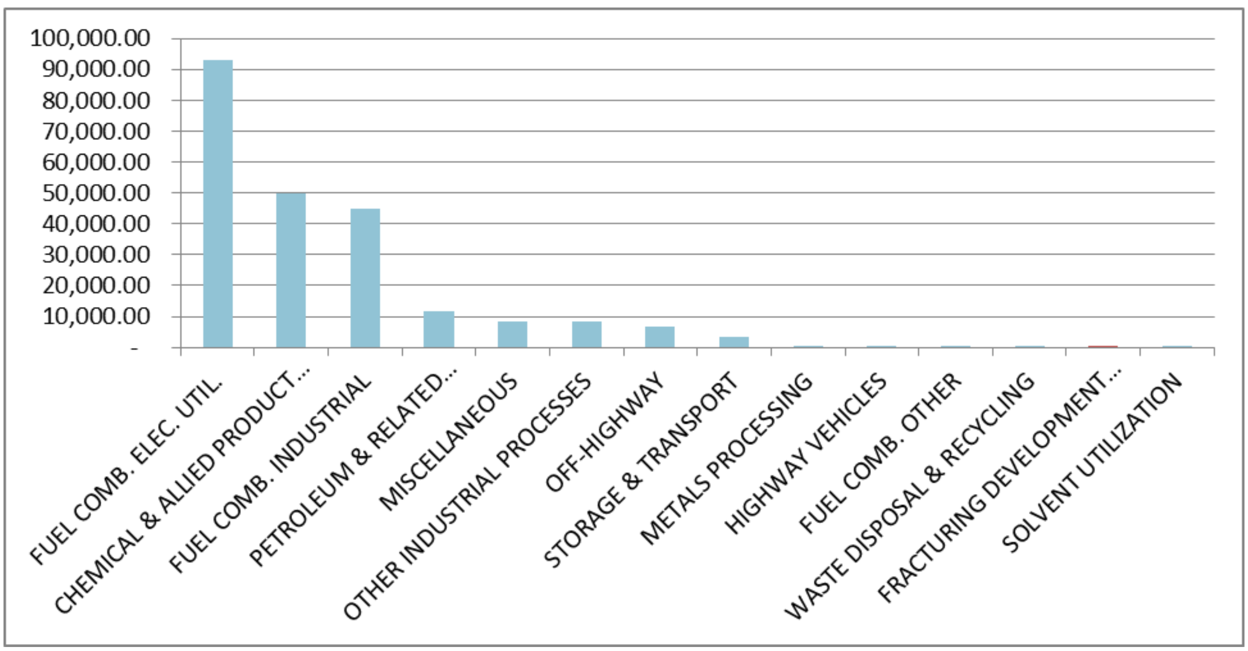

Figure 5.8: Comparison of SO_x emissions.

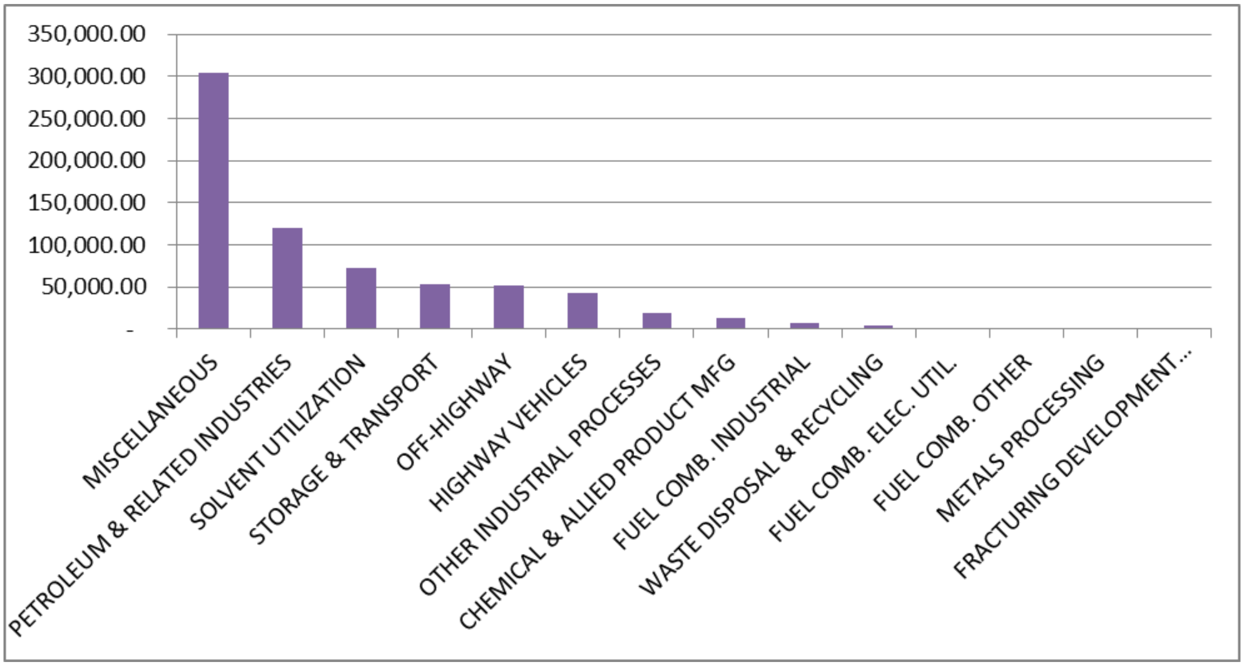

Figure 5.9: Comparison of VOC emissions.

Emissions were also looked at on a per-well by operator basis. Only emissions from drivers that can be calculated on a per well basis and known for any certain company were used (i.e. emissions for fracturing). Also, only Frac Focus reported data is analyzed on a per company basis, not simulated estimates. Table 5.9 shows the emission estimates for fracturing operations for each company represented. Callon Petroleum Operating Co. is estimated to have the highest emissions overall for hydraulic fracturing operations. The 'big' companies (i.e. Chesapeake, Encana, and Exco; highlighted in green) are middle emitters of all the companies, and middle sized companies are of the top emitters. The highest 'small' company emitter is EOG (all small companies are highlighted in red).

Table 5.9: Fracturing emission by company (tons per well for 2011).

Organization Name	NO_x	CO	VOC	PM	CH_4
Callon	0.06848	0.04280	0.01113	0.00462	0.00419
BHP Billiton WSF	0.06661	0.04163	0.01082	0.00450	0.00407
Eagle Oil	0.06648	0.04155	0.01080	0.00449	0.00406
BHP Billiton Petro	0.06583	0.04114	0.01070	0.00444	0.00402
Comstock	0.06569	0.04106	0.01067	0.00443	0.00402
QEP Energy	0.06432	0.04020	0.01045	0.00434	0.00393
EOG	0.06378	0.03986	0.01036	0.00431	0.00390
Exco	0.06340	0.03963	0.01030	0.00428	0.00388
Goodrich Petroleum	0.06330	0.03956	0.01029	0.00427	0.00387
Samson	0.06329	0.03955	0.01028	0.00427	0.00387
BE USA LLE	0.06311	0.03944	0.01026	0.00426	0.00386
BHP Billiton (KCS)	0.06269	0.03918	0.01019	0.00423	0.00383
XTO	0.06261	0.03913	0.01017	0.00423	0.00383
EP Energy	0.06222	0.03889	0.01011	0.00420	0.00380
Fortune Resources	0.06190	0.03869	0.01006	0.00418	0.00378
Enduro Operating	0.06151	0.03844	0.01000	0.00415	0.00376
Chesapeake	0.06138	0.03836	0.00997	0.00414	0.00375
Matador Production	0.06133	0.03833	0.00997	0.00414	0.00375
Encana	0.06125	0.03828	0.00995	0.00413	0.00374
Swepi	0.06094	0.03809	0.00990	0.00411	0.00372
Forest Oil	0.06007	0.03754	0.00976	0.00405	0.00367
Tellus Operating Group	0.05996	0.03748	0.00974	0.00405	0.00367
JW Operating	0.05987	0.03742	0.00973	0.00404	0.00366
Anadarko	0.05964	0.03727	0.00969	0.00403	0.00365
Endeavor	0.05854	0.03659	0.00951	0.00395	0.00358
Indigo Minerals INC	0.05286	0.03304	0.00859	0.00357	0.00323
Nadel and Gussman Ruston LLC	0.04998	0.03124	0.00812	0.00337	0.00306
SM Energy Company	0.04756	0.02973	0.00773	0.00321	0.00291

Emissions by parish for fracturing were also considered. Table 5.10 shows the comparison of emissions in TPY for the year 2011. De Soto parish is estimated to have the most emissions overall; this is due to the greater amount of fracturing activity occurring in the parish compared to the other parishes. In fact, in 2011, De Soto Parish accounted for almost 50% of fracturing wells in the Haynesville Shale.

Table 5.10: Fracturing emissions by Parish (tons per year for 2011).

Parish	Nox TPY	CO TPY	VOC TPY	PM TPY	CH4 TPY
De Soto	73.4	45.9	11.9	5.0	4.5
Red River	22.6	14.1	3.7	1.5	1.4
Caddo	19.0	11.9	3.1	1.3	1.2
Sabine	11.0	6.9	1.8	0.7	0.7
Bienville	8.1	5.1	1.3	0.5	0.5
Bossier	7.3	4.6	1.2	0.5	0.4
Natchitoches	0.5	0.3	0.1	0.04	0.03
Webster	0.2	0.1	0.04	0.02	0.01

5.1.4. Well Development Air Emissions: Learning by Doing

As time goes on and more wells are being drilled, air emissions mimic the trend of drilling; as it increases air emissions also increase. In the drilling process, which arguably emits the most air emissions, drilling time is a main driver. Since drilling time was not able to be analyzed on a well to well basis and across all years, we were not able to show that drilling time decreased leading to a decrease of air emissions per well. But, many sources do state that drilling time for unconventional wells is dramatically decreasing as drillers become more familiar with the shale. Chesapeake reported that on average it took them 64 days to drill a well in 2008 and by the middle of 2009 it took only 47 days (Webster, 2009). Petrohawk stated a similar decrease of days within one year, at the beginning of 2012 they were drilling a well in 50 days and by the end it took only 45 days (OilShaleGas.com, 2014). On a company level, this does show evidence of learning by doing for the drilling process.

Fracturing emissions follow the same trend as drilling and number of wells spudded. Emissions are driven by the number of stages performed on a well. Stages are continually increasing because of the ability to obtain more natural gas for each stage completed. Though emissions may not being decreasing, drillers are learning that by completing more fracturing stages, more oil and/or natural gas is able to be recovered.

5.2. Water Use in Haynesville Shale Drilling Operations

Frac Focus reported water use per well was combined with simulated water use to get overall water use for each year. Though only about 30 percent of the data is represented by actual reported numbers, the strength of the data increases as the years going on, providing a more accurate picture of water use. For comparative analyses, 2010 data was used because industry use data was only available for that year. For comparing companies a distinction was made between top three 'big' companies and bottom four 'small' companies, same as air emissions. Only known water use statistics were used to compare companies, not simulated. Finally, Parishes were also compared to one another and to other total water use in the Parish. Known water use was used to compare the different Parishes, but simulated water use was used to compare to total water use of the Parish to give a better representation of fracturing activity.

5.2.1 Water Use in Haynesville Shale: Estimated Use Rates

In Table 5.11 the simulated average amount of water used per well rises from 2007 to 2011, but drops by about half a million gallons in 2012. Though there is not a known explanation for this drop in water use, it may be attributed to a growing efficiency in water use or the declining rates of the shale and the lower economic returns of the shale, at the time. Water use does increase on a per well basis through 2011, this can be attributed by the longer lateral lengths and the higher number of stages fractured throughout the years, which requires more water. Interesting to note, the maximum water used per well also increases over time until 2011, this is indicative of the measures drillers are willing to go to, to get the gas out of the shale. It also shows how difficult the Haynesville Shale is to retrieve the natural gas sometimes. Furthermore, the standard deviation continues to increase, showing a higher variability in the amount of water

used per well. This could be connected to the different companies entering the shale play, as time goes on, and learning lag effects.

Table 5.11: Estimated water use for the Haynesville Shale on a per well basis.

Year	Average	Min	Max	Std
2007	3,691,802	2,231,004	5,019,403	1,145,206
2008	3,460,253	625,464	5,592,848	1,207,282
2009	3,564,946	1,517,919	6,590,304	1,174,089
2010	4,054,394	478,513	11,868,486	1,509,802
2011	5,463,441	367,290	34,258,678	2,383,943
2012	4,976,308	510,384	14,365,376	2,648,553

5.2.2. Water Use in Haynesville Shale: Total Water Use

Table 5.12 shows total water use in the Haynesville Shale from its start in 2007. Total water use increases throughout the years until 2010 to 2011. This slight decrease can probably be attributed to the simulation method used for unknown water use. Overall the total water use, again, copies that of the trend of number wells drilled throughout the years.

Table 5.12: Total water use in the Haynesville Shale

Year	Total water use
2007	22,150,814
2008	439,452,118
2009	1,896,551,113
2010	3,665,172,498
2011	3,469,285,290
2012	716,588,390

5.2.3. Water Use in Haynesville Shale: Comparative Analysis

In 2010, The Haynesville Shale used 3.7 billion gallons of water for drilling and fracturing purposes. But how much is 3.7 billion gallons of water? Table 5.13 shows water withdrawals by major industry in 2010, Haynesville development uses 5 percent of water used by the fifth highest user, Paper Products. Also, the fracturing total water amount does not account for how much of it is from flowback recycling and/or from brackish formations. These are just two ways

operators try and reduce their freshwater use. Table 5.13 shows the water use yearly (gallons) by each major industry source in 2010 as reported by Louisiana Department of Transportation.

Table 5.13 Water use by major industry (2010)

Major Industry	Total Water Used Per Year (gal)
Power Generation	1,255,965,000,000
Chemicals	525,950,400,000
Aquaculture	109,500,000,000
Irrigation	91,250,000,000
Paper Products	55,388,750,000
Petroleum Refining	23,122,750,000
Food Products	17,158,650,000
Estimated Total Water Use for Fracturing	3,665,172,498
Live Stock	2,956,500,000
Rubber and Plastics	1,445,400,000
Primary Metals	992,800,000
Lumber	715,400,000
Transportation Equipment	573,050,000
Glass, Clay, and Concrete	459,900,000
Coal and Lignite mining	452,600,000
Nonfuels and Nonmetals Mining	273,750,000
Building Construction	255,500,000
Metal Products	109,500,000
Instramentation	91,250,000

Water use was also looked at on a per company basis in Table 5.14. The top three 'big' companies were looked at and then compared to the rest of the companies and then the bottom four 'small' companies. Though, every company shows an increase of water use throughout the three years reported, the big companies increase at a much slower rate compared to everyone else; especially the smaller companies, who almost double their water use every year[7].

Water use was also looked at by parish, Table 5.15. Red River uses the second most or most water per well throughout all three years. This is probably due to the geologic formation make up in the region for the shale. De Soto is one of the lowest water using per well parishes

[7] Average water use and water use per lateral length is shown in Table A.5.

throughout the years. This can be attributed to the possibility of learning effects throughout the parish because of its high amount of activity each year.

Table 5.14: Average water use for big companies, all companies minus big, and small companies.

	BIG avg	Everyone else	Small avg
2010	5,259,032	4,772,545	3,785,633
2011	5,963,754	5,776,642	6,624,200
2012	6,064,241	7,853,426	12,952,060

Table 5.15: Average and total water use by Parish (million gallons).

Parish	2010 Avg. Water Use Per Well	2010 Total Water Use	2011 Avg. Water Use per Well	2011 Total Water Use	2012 Avg. Water Use Per Well	2012 Total Water Use
Bienville	5.50	16.49	5.58	111.64	5.13	112.89
Bossier	8.27	8.27	6.34	196.68	5.69	68.33
Caddo	.	.	5.30	270.16	5.69	73.93
De Soto	4.55	54.57	5.24	1,335.32	5.19	964.81
Natchitoches	.	.	3.45	13.81	3.48	6.97
Red River	6.60	46.23	7.00	546.04	8.37	544.26
Sabine	3.72	3.72	6.10	359.62	6.06	381.61

In Figure 5.10 total Parish water use (less fracturing activities) and fracturing water use was compared for each Parish. Three of the eight Parishes analyzed, showed fracturing activity using more water than the Parish did for other municipal, industrial, etc. use. These three Parishes, De Soto, Red River, and Sabine have populations of 26,656; 9,091; and 24,233, respectively. Only De Soto Parish is cited to have some other major industry use water which is industrial use. The two other Parishes main water withdrawal comes from municipal use. For Red River and Sabine Parishes, fracturing accounts for more water use than the rest of the Parish most likely because of small population size and that there is no other industry there using a great deal of water. De Soto Parish uses much more water for fracturing purposes because there are a lot more wells in

the Parish but with a major industry also being in the Parish, it is important to note that water use is higher than that of the rest of the Parish.

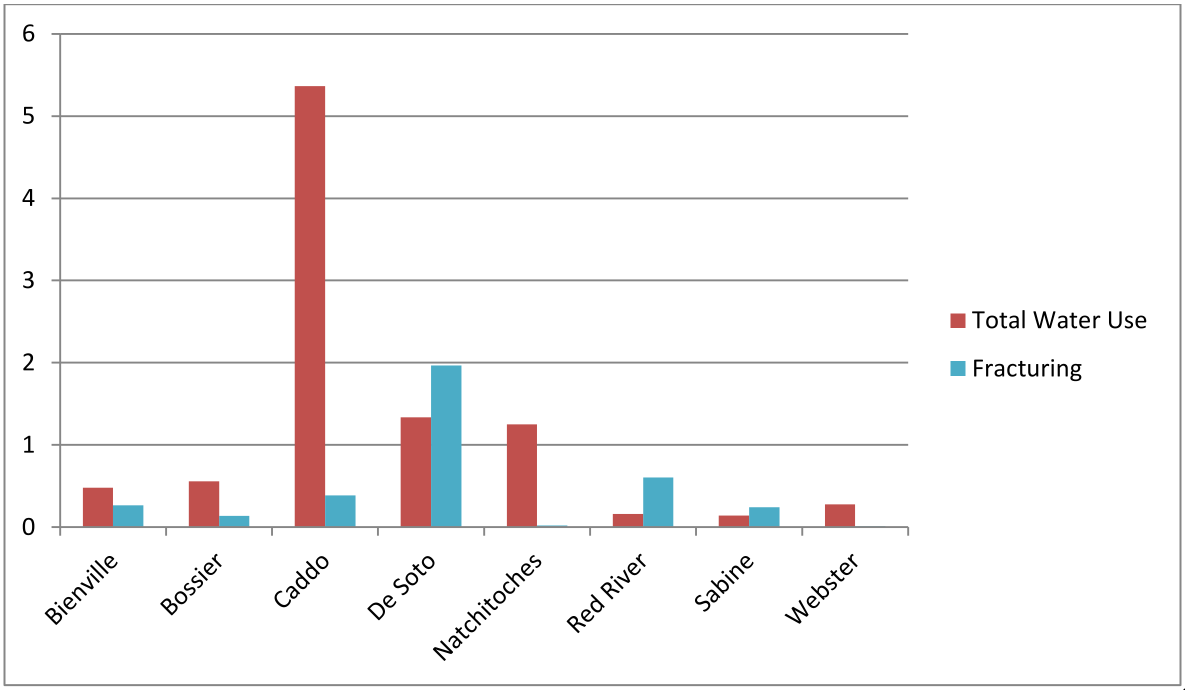

Figure 5.10: Total water use compared to estimated fracturing water use by Parish for 2010.[8]

5.2.4. Water Use in Haynesville Shale: Learning by Doing

A large quantity of water is need to fracture unconventional wells, and without new technology water will still be the resource needed to obtain the oil and natural gas that is trapped in these wells. The Haynesville Shale shows some signs of learning by doing when it comes to water use. As mentioned before, bigger companies are using increasing amounts of water per fracturing job, but at a much slower rate than small companies. This gives evidence that there is some learning going on at the company level that is not being transferred to all companies. Also, average water use per well in De Soto Parish declines from 2011 to 2012, being a possible indicator that on a Parish level some learning is taking, and it is also not of the highest water uses of each Parish.

[8] Power generation and public water supplies drives most of Caddo Parish's water use.

5.3. Chemical Use in Haynesville Shale Fracturing Operations

Chemical use was analyzed for three chemicals that this paper deemed were of top concern, hydrochloric acid (HCl), phenol, and quaternary ammonium Salts (quats). These three chemicals were estimated on a per well basis, and a total use basis. The three chemicals were chosen based on their total representation throughout the shale and their percent concentration when used, according to Frac Focus data.

5.3.1. Chemical Use in Haynesville Shale Fracturing Operations: Estimated Chemical Rates

From frac focus data, it was found that the probability of an operator using HCl in fracturing solution was 34.4%. The range of HCl concentration was found to be 0.06% to 0.417% in fracking fluid. The probability of using phenol was found to be 8% of all wells. The range of concentration of phenol was 0.001% to 0.417% of fracking fluid. The probability of quats being used in fracking fluid was found to be 7.5% at a range of concentration from 0.00001% to 0.032%. After running a Monte Carlo simulation and creating a distribution, descriptive statistics were ran on the simulated concentrations of each chemical. Below, in Table 5.16 is the summary of those descriptive statistics.

Table 5.16: Simulated concentration (in percent) in fracturing fluid.

Concentrations	Average	Min	Max	Std
HCL	0.21	0.0013	0.42	0.12
Phenol	0.086	0.0027	0.18	0.049
Quats	0.02	0.0002	0.04	0.012

These concentrations were then transformed into gallons used for each fracturing job, by taking the number of gallons of water used in the fracking fluid and equating that, to the number of gallons of each chemical used. The average water use, per well, for 2011 was used and a concentration of water in frack fluid of 90% was used for this simple demonstration. Below, in Table 5.17 are the statistics for each chemical used in gallons. Hydrochloric acid is usually the

largest liquid component (other than water) found in fracturing fluid. The hydrochloric acid is diluted by the water and other chemicals used in the fluid, so once it is pumped down the well, it is at a much lower concentration, and as the HCl remains in the formation, it continues to become diluted (Geology.com, 2014). Phenol is used because once pumped down into a well bore, the phenolic resins coat the sand to help keep the fractures open. The phenolic resins will cure at a certain temperature deep in the formation, but depending on the temperature they can leach formaldehyde and phenol (Mazerov, 2013). New technology has come out to decrease the phenolic resin use for sand propants. This new technology is more environmentally friendly and cost effective (Mazerov, 2013). As of July 2013, the EPA released a new rule under the Toxic Substances Control Act (TSCA) that the manufacture, import, or process of quaternary ammonium compounds, along with other chemical substances, must be reported to the EPA. Quats are more of an emerging fracturing fluid chemical and is used to eliminate bacteria in the water that might produce corrosive by-products (regulations.gov, 2013). The EPA's new rule was set forth because of the potential serious human and aquatic health effects caused by quats, as mentioned before.

Table 5.17: Simulated potential gallons of chemicals per fracturing job.

Gallons	Average	Min	Max
HCL	12,489	83	25,308
Phenol	5,219	163	11,006
Quats	1,220	10	2,426

5.3.2. <u>Chemical Use in Haynesville Shale Fracturing Operations: Estimated Total Use</u>

The total volume used for each chemical throughout the shale was estimated using the average amount predicted for each chemical and then the percent of wells represented for each chemical, shown in Table 5.18. Almost 10 million gallons of hydrochloric acid, almost 1 million

gallons of phenol, and just over 210 thousand gallons of quats were estimated to have been used over the 5 years of fracturing studied.

Table 5.18: Total chemical use (gallons) for all years 2007- Oct 2013.

	# of wells that used chemical	Total Chemical Use (gallons)
HCl	793	9,903,835
Phenol	184	962,859
Quats	173	210,934

5.3.3. Chemical Use in Haynesville Shale Fracturing Operations: Comparative Analysis

Chemical use by parish was also looked at for each chemical analyzed. Table 5.19 shows the number of wells the chemical was used in for each parish, according to self-reporting by frac focus. This is a simple count of whether or not a well used the chemical; the concentration of the chemical was not analyzed by parish. De Soto Parish has the highest representation of the three chemicals of concern. Since De Soto Parish is a parish with a vast amount of fracturing, it should be a parish that must monitor fresh water closely.

Table 5.19: Chemical use by Parish.

Parish	HCl Count	Phenol Count	Quats Count
Bienville	1	16	2
Bossier	.	4	.
Caddo	3	8	9
De Soto	81	23	93
Red River	.	10	2
Sabine	1	4	2

Table 5.20 looks at what the top three chemicals were used for in fracturing fluid and then what other products they were used for in the market place. HCl is used in many different processes and cleaning purposes. Phenols are used for many different manufacturing products. It is used as an adhesive for plywood, and is also a heat resistant component for household appliances. Quats are mostly used in household cleaning products.

Table 5.20: Top three chemicals analyzed and other products they are used in.

Chemical	Purpose in Fracturing Fluid	Other Product Used In
HCl	Helps to dissolve minerals and initiate cracks in the rock	bleach, leather processing
Phenol	Eliminate bacteria and help coat sand propants	plywood, window glazing, flat screen TVs
Quats	Eliminates bacteria in the water that produces corrosive by-products	disinfectants

Chemical use was not compared to other industry sources because no other industry uses chemicals similar to the way hydraulic fracturing uses chemicals. Chemicals used in a chemical plant are transformed to make other products and are hardly left in their original state. Likewise, there was no way of connecting chemical use to learning by doing because chemicals vary so differently between operator and shale formation. The expanse of time the chemicals were presented was too short and the distribution of whether a chemical was used or not was also variable not allowing for a feasible trend to been formed.

CHAPTER 6: SUMMARY AND CONCLUSIONS

6.1. Summary

This paper analyzed the use of unconventional drilling in the Louisiana portion of the Haynesville Shale. Well development activities were considered and analyzed for air emissions, water use, and chemical use. Well development activities were defined into two main categories: drilling and fracturing; and then support activities of: heavy duty traffic and completion venting. Though the Haynesville Shale has been explored for much of the last fifty years, unconventional drilling found its start in 2007, when natural gas prices were high and drilling technology was available to allow unconventional drilling positive economic returns.

Air emission estimations were calculated for years 2007- October 2013. Well specific data was used when possible; otherwise a known range was used along with a Monte Carlo simulation to account for all possible distributions of the parameters. The highest tons per well air emitting year was 2011. This can be attributed to the increase in wells spudded in the year, and a larger representation of all types of companies throughout the shale (i.e. both big and small companies), and not all companies use best management practices. Air emission rates per well for fracturing continues to rise throughout all years studied. Fracturing emission rates increase due to longer lateral lengths and increasing number of stages fractured. Traffic emission estimations mirrored that of number of wells spudded, throughout the years. Completion venting was calculated as a constant per well, and no change was able to be determined. Of all four well development activities studied, drilling was the top producer for all air emission pollutants, except methane which was highest during fracturing. Total air emissions for every pollutant peaked in 2011 and dropped off thereafter. This peak is due to the higher number of wells spudded in 2011 compared to every other year. Air emissions were compared to other major

industries in the State. The pollutant of major concern in these comparisons would be that for NO_x. About 97 percent of NO_x emissions were found to occur in the drilling phase of development activities. NO_x emissions rival that of chemical and allied product manufacturing in the State. Big companies were found to be 'middle of the pack' emitters while small companies varied, and were found to be higher emitters than some big companies (emissions at a per well basis).

Water use estimates were calculated for all years, 2007- 2012 using Frac Focus, self-reported, data. Over the six years analyzed, only 30 percent of the wells were reported to Frac Focus, the remaining 70 percent had to be simulated using a Monte Carlo approach. It is important to note, that as the years progressed, water use data per well grew stronger in representation, making most of the simulated water use for earlier years studied.

Water use on a per well basis was shown to increase every year until 2011. Longer lateral lengths and increasing number of stages needing to be fractured require more water to be used, causing this increase. The drop from 2011-2012 may be a function of the simulation method used, or may be attributed to some learning by doing occurring at the shale level. Total water use over the years increases until 2010, and slightly decreases in 2011, which is most likely due to the simulation method. The increase throughout the years can be attributed to the increasing number of wells being spudded in the shale each year, until 2012. The total estimated water use for 2010 was compared to that of major industry water use. Fracturing water use was ranked 8^{th} among all major industries in the State, using 3.67 billion gallons of water. This was less than 0.3 percent of water used for power generation, the top water user, in the State. The major difference in water use for power generation and water used in fracturing is that water use for power can be returned to the system, whereas water used for fracturing, many times, cannot be returned.

Though fracturing doesn't use nearly as much water as other industries the water used in fracturing may be removed from the system. Different size companies were compared and found to use differing amounts of water. Though all companies were found to increase their water usage throughout the years on a per well basis, the bigger companies increased their use at a much slower rate than smaller companies. Also, De Soto Parish, the Parish with the most wells, was shown to use less water on average than the average water use for the whole shale. Three Parishes were found to use more water for fracturing than water used for anything else in the Parish. The three Parishes were De Soto, Red River, and Sabine.

Chemical use in the Haynesville Shale was also studied. Three chemicals of concern that are used in fracturing fluid were deemed to be: hydrochloric acid, phenol, and quaternary ammonium salts. Thirty-four percent of the wells were found to use HCl, 8 percent were found to use phenol, and 7.5 percent were found to use quats. The average concentrations per well of each chemical in fracturing fluid were found to be 0.21, 0.086, and 0.02 for HCl, phenol, and quats, respectively. Meaning on average a well uses 12,489 gallons of HCl, 5,219 gallons of phenol, and 1,220 gallons of quats.

Learning by doing was also found to have occurred in the shale region. Big companies were shown to emit less air emissions during the fracturing stage of well development. Only the fracturing stage was looked at because that was the only stage where per well, and thus per company, data was available. Though drilling time was simulated, self-reported numbers from several operators showed decreasing drilling time over the years. Also, big companies used less water throughout the years compared to small companies, showing learning at the company level. On a Parish level, De Soto was found to use on average less water per well than the whole shale average, showing evidence of some regional learning taking place.

6.2. Conclusions

Overall, it was determined that the Haynesville Shale emits an obvious amount of air emissions but still is much less than that of other major industries in the State; the shale uses a vast amount of water, and is especially a great amount in some local parishes; and chemicals used in fracturing should be handled with care because of the amount used and the relative toxicity to the environment and humans of each chemical. It is shown that the Haynesville Shale has become more efficient in unconventional drilling activities by decreasing drilling time, increasing lateral lengths and stages to recover more resources. Though still of concern, environmental effects have lessened from big companies because they have decreased their air emissions and slowed their water use per well over time.

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APPENDIX

Table A.1: Sources used to derive drilling days for duration.

Source	Drilling Days	Year Reported
Chesapeake	64	2008
Chesapeake	47	2009
Petrohawk	45-50	2012
LOGA	20-30	N/A
Haynesvilleshalegas.org	30-90	N/A
Nola.com/news	30-45	2010

Table A.2: Emission factors used for drilling, fracking, and traffic and their respective sources

	NO_x	**CO**	**VOC**	**PM**	**SOx**	**CO_2**	**CH_4**
$EF_{drilling}$	4.8[a]	2.6[a]	0.3[b]	0.15[a]	0.00809[b]	1.16[b]	0.000705[b]
$EF_{fracking}$	8.0[c]	5.0[c]	1.3[c]	0.54[c]	n/a	n/a	0.489[d]
$EF_{traffic}$	11.3[e]	3.4[e]	0.65[e]	0.28[e]	n/a	n/a	n/a

[a]Tier II: Federal Register Vol 63, No. 205; [b]AP 42 Ch. 3 Sec 4-1; [c]EPA nonroad base engine; [d]Allen et al. (2013); [e]EPA OTAQ

Table A.3: Factors used for emission equations

Drilling	**Low**	**Mean**	**High**
HP	1200[a]	1122[b]	4000[a]
LF_{avg}		0.67[b]	
$T_{drilling}$	30[c]		30[c]
% on-time	0.5[e]		1[e]
Fracking			
HP		1000[b]	
LF_{avg}		0.5[b]	
N_{stages}	4[c]	14[c]	35[c]
Traffic			
L_{trip} (miles)	52[d]		89[d]
N_{trip}	113[d]		174[d]
Completion Venting			
P_{gas} (kg/m3)		0.712[b]	
Volume (MCF)		2417[b]	
F_i (mass fraction)		0.34[b]	

[a]Kaiser & Yu (2013); [b]Envrion; [c] simulated duration; [d]Environ Haynesville Shale mobile article; [e]Roy et al.

Table A.4: Water use statistics for the Haynesville Shale

Year	Month	sum water use (total)	average water use per well	min water use per well	max water use per well	standard deviation
2009	6	4,372,788	4,372,788	4,372,788	4,372,788	.
2009	12	4,515,735	4,515,735	4,515,735	4,515,735	.
2010	3	15,638,112	7,819,056	6,695,010	8,943,102	1,589,641
2010	4	10,952,397	5,476,199	5,159,883	5,792,514	447,338
2010	6	12,896,532	4,298,844	2,778,144	5,108,250	1,317,878
2010	7	14,205,870	4,735,290	3,716,370	5,874,834	1,084,276
2010	9	41,559,323	5,937,046	4,909,878	8,272,866	1,216,489
2010	10	15,986,866	5,328,955	3,803,226	6,296,500	1,337,079
2010	11	5,931,406	5,931,406	5,931,406	5,931,406	.
2010	12	12,115,033	4,038,344	3,534,104	5,046,300	872,915
2011	1	75,729,381	6,310,782	3,511,745	8,687,952	1,408,488
2011	2	140,609,552	5,858,731	1,767,360	8,674,386	1,548,312
2011	3	170,359,778	5,874,475	3,703,308	7,292,067	948,299
2011	4	211,184,959	5,557,499	3,830,526	7,905,156	1,054,278
2011	5	161,651,051	5,574,174	478,513	11,100,936	2,147,791
2011	6	251,233,544	5,582,968	3,283,350	11,669,322	1,528,364
2011	7	308,882,964	5,418,999	3,034,038	8,331,036	1,268,944
2011	8	269,089,860	5,077,167	2,327,514	9,389,016	1,551,715
2011	9	374,320,487	6,136,401	2,586,799	11,868,486	2,045,348
2011	10	286,147,473	5,722,949	3,395,196	9,735,810	1,710,264
2011	11	233,846,687	5,703,578	2,449,989	11,669,322	2,203,518
2011	12	317,391,596	5,988,521	3,082,417	13,022,982	1,895,171
2012	1	258,113,940	5,162,279	510,384	12,270,468	2,022,823
2012	2	264,569,839	5,511,872	2,572,348	8,687,952	1,620,259
2012	3	246,415,864	6,318,355	3,019,423	14,488,362	2,203,758
2012	4	217,214,878	5,716,181	1,515,503	10,294,830	2,392,709
2012	5	181,178,552	6,470,663	2,925,762	34,258,678	5,837,341
2012	6	432,205,369	6,087,400	367,290	14,273,538	2,706,802
2012	7	153,505,828	6,140,233	3,108,384	10,112,433	2,272,297
2012	8	123,761,200	6,513,747	2,945,450	14,011,788	3,627,607
2012	9	89,214,463	6,372,462	3,091,279	11,750,718	2,154,193
2012	10	66,881,386	6,080,126	3,635,982	14,205,196	3,128,698
2012	11	65,474,424	6,547,442	3,242,078	14,365,376	3,561,942
2012	12	46,424,061	5,803,008	3,028,451	9,793,088	2,876,314

Table A.5: Average water use and average water use per lateral shown by company for big and small companies (green=big company; red=small company).

Year	Avg Water Use	average lateral length	water/lateral	Company
2009	6590304	4572.12	1,441	Chesapeake Operating INC
2010	4,842,262	4,571	1,059	Chesapeake Operating INC
2010	6,683,673	4,472	1,495	Encanc Oil & Gas (USA) INC
2010	4,251,162	4,765	892	Exco Operating Company LP
2010	6,251,242	4,903	1,275	EOG Resources INC
2010	2,778,144	4,876	570	Samson Contour Energy E&P
2010	2,327,514	4,732	492	XTO Energy INC
2011	5,184,996	4,566	1,136	Chesapeake Operating INC
2011	8,410,232	5,235	1,607	Encanc Oil & Gas (USA) INC
2011	4,296,034	4,818	892	Exco Operating Company LP
2011	4,906,257	4,638	1,058	JW Operating Company
2011	8,915,088	5,456	1,634	EOG Resources INC
2011	2,665,143	4,604	579	Samson Contour Energy E&P
2011	10,010,310	4,492	2,229	XTO Energy INC
2012	4,615,004	4,559	1,012	Chesapeake Operating INC
2012	3,551,116	5,730	620	Exco Operating Company LP
2012	10,026,604	4,770	2,102	Encanc Oil & Gas (USA) INC
2012	12,952,060	4,818	2,688	XTO Energy INC

VITA

Emily C Jackson, a native of San Antonio, Texas, received her bachelor's degree at Texas A&M University in College Station, Texas in December 2011. She began her master's work in the fall of 2012 at Louisiana State University, in Baton Rouge, Louisiana. Upon arrival at LSU, Emily began researching different topics associated with hydraulic fracturing. This interest led to a connection with the Center of Energy Studies, and David Dismukes, at LSU, where Emily does her graduate research work. After graduation, Emily plans on working for a state agency as an environmental specialist.