NORTH LOUISIANA HAYNESVILLE FRACTURE DATA WITH GEOSPATIAL CALCULATION

A Thesis

by

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ABSTRACT

Known as one of the most productive shale gas plays in the US, the Haynesville shale gas play covers 9,000 square miles from East Texas to North Louisiana. With horizontal wells and multi-stage hydraulic fracturing, gas production has increased rapidly. The Haynesville shale is a geologically unique dry gas play with relatively large depth, high temperature, high reservoir pressure gradient, ultralow permeability, and soft formations. The harsh conditions have brought challenges in drilling and completion and have made the gas production very sensitive to the gas price. Under these circumstances, top priority strategies in the shale's development are to cut the cost and increase reserves. The object of this study is to perform a regional investigation of the effect of drilling and completion practice on the cumulative production.

There has been much debate about the relationship between proppant and fracturing fluid usage and cumulative production. Some articles report more proppant and fracturing fluid loading greatly boosts their production while other researches state that there is no relationship among them. The controversial findings usually come from well-based analysis, where the geospatial information regarding the analyzed well and its neighbors is either totally neglected or extremely simplified. The basic hypothesis of this work is that the role of completion parameters can be better understood if detailed geospatial information is used in the analysis. Using production data from Drillinginfo and completion data from the FracFocus website, we create a visual presentation of the most prolific parish (De Soto Parish) of the Haynesville shale play. The study area is decomposed into 640-acre (pseudo-)sections. Wells are assigned to the sections based on their subsurface path. If a well's path falls into more than one section, geospatial weight percentages are calculated. Then the main completion and production variables are calculated for

each section using the pre-determined geo-spatial weights. This allows us to conduct a section-based analysis of the effect of completion variables on cumulative production. We perform section analysis and focus on finding potential correlations. Those correlations will lead us to analyze current development strategy and suggest its improvement in the future, depending on the changing gas-price environment.

DEDICATION

To my Parents who always supported and encouraged me throughout my life.

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Contributors

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The data analyzed for Chapter 3 was provided by Professor Dr. Peter Valko.

All work for the thesis was completed by the student independently, under the advisement of Dr. Peter Valko of the Department of Harold Vance Department of Petroleum Engineering.

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NOMENCLATURE

BSCF	Billion Standard Cubic Feet
EIA	U.S Energy Information Administration
EUR	Estimated Ultimate Recovery
MCF/D	Million Cubic Feet per Day
LOGA	Louisiana Oil and Gas Association
PLSS	Public Land Survey System

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CHAPTER I

INTRODUCTION

1.1 Haynesville Shale Overview

1.1.1 Production Potential in North Louisiana

Natural gas is one of the primary energy sources in the US. According to the EIA energy outlook, natural gas consumption is the second largest domestic energy source consumed, as shown in **Fig. 1**. Since the 1820's, shale gas innovation has been developed in the US. Natural gas production has come into a new era with the capability of producing gas from shales. The advances in horizontal drilling and hydraulic fracturing allow natural gas extraction from shale formations at an economically viable rate even with ultra-low matrix permeability. In recent years, a large portion of the domestic total natural gas production has come from shale gas plays. In 2017, approximately 60% of natural gas produced was shale gas. The prediction of the EIA energy outlook indicates that the demand for natural gas will remain robust for the next two years, but the growth of demand and the gas price are both stagnant (EIA, 2017).

Early in 2007, Chesapeake Energy first discovered the Haynesville shale play and named it "Haynesville shale" due to the relation to Haynesville carbonates in east Texas and Louisiana (Hammes et al, 2011). The success of the horizontal Haynesville wells sparked a lot of interest in the oil industry leading to a surge in land acquisition in the basins (Durham, 2011). Since then the production in Haynesville shale has increased considerably. With commercial development, the Haynesville shale play became one of the best producing dry gas reservoirs in the US. As observed in **Fig. 2**, the natural gas production is huge while the oil production is quite limited in the Haynesville region. As of March 2018, there exist approximately 58 rigs in the area. (EIA, 2018)

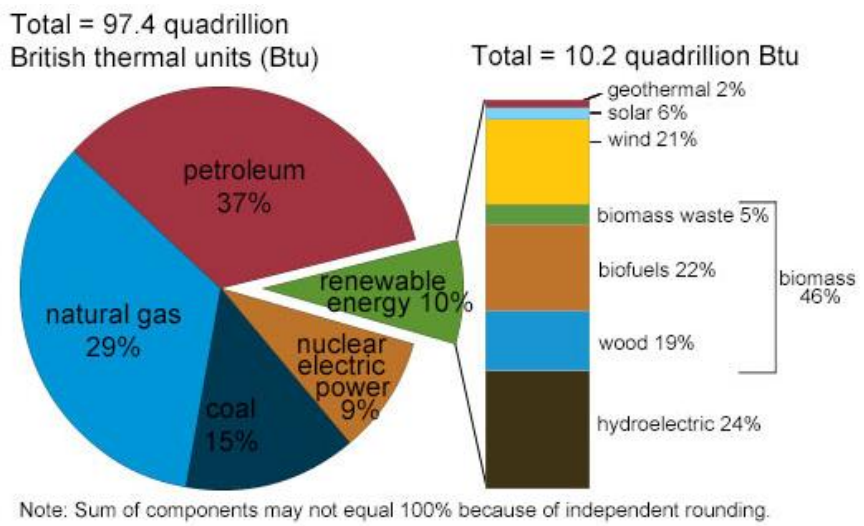

Figure 1. Source of Energy Consumption in the US in 2016 (EIA, 2017)

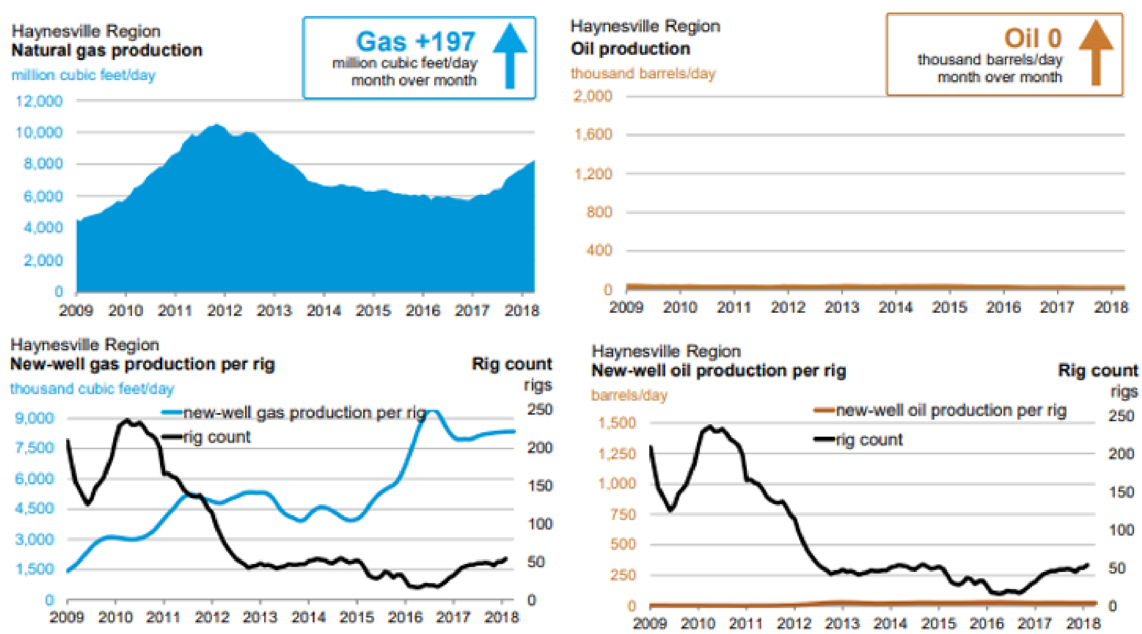

Figure 2. Oil and Gas Production from Haynesville Region (EIA, 2018)

The discovery of the Haynesville shale has had a profound impact on overall gas production in Louisiana as seen in **Fig.3**. The natural gas production in Louisiana quadrupled between 2007 and 2011, but the reduction in the well-head price of natural gas has reduced the number of new wells entering production phase, lowering the total gas production rate in the area. The price in Louisiana natural gas fell by 6% from 2015 to 2016, dropping the production from 2.9 trillion cubic feet in 2012 to 1.67 trillion cubic feet in 2016. The Haynesville/Bossier shale located between Texas and Louisiana has a proven reserve of 12.8 trillion cubic feet (Louisiana Department of Natural Resources). The Haynesville wells have had a huge yearly decline rate of between 50% and 80% (Goddard et al, 2009). Existing research places the EUR of the Haynesville Shale in North Louisiana at 34 TCF hence leading to a 13.6% recovery factor.

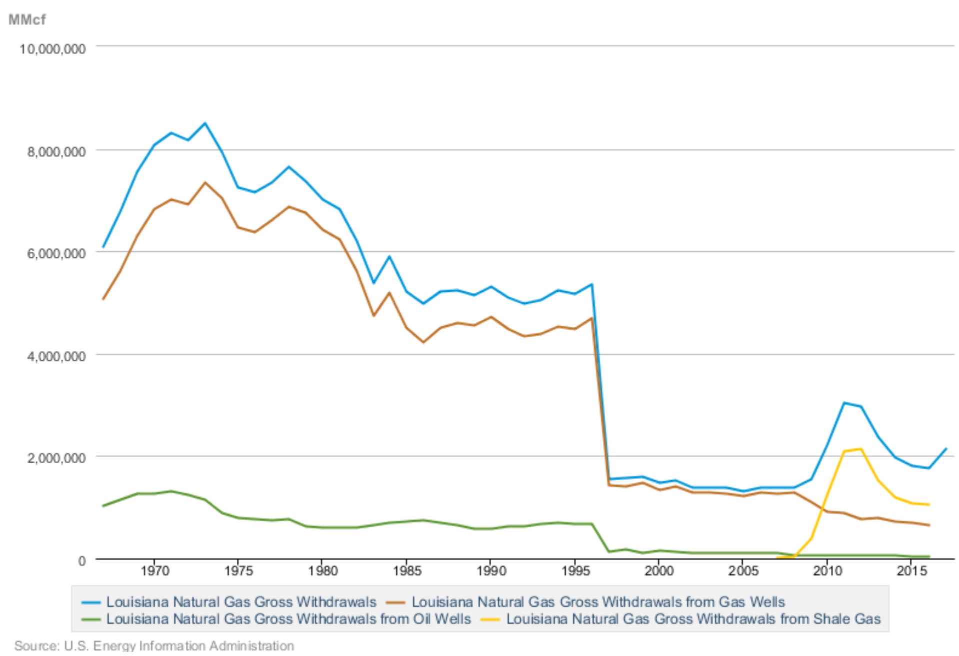

Figure 3. Natural Gas Gross Withdrawals and Production (EIA, 2017)

1.1.2 Drilling and Completion Overview

Geologists consider the Haynesville Shale an unconventional natural gas deposit since the methane gas is not located in highly porous rocks. These rock formations do not create easy-to-access pockets of the gas. To address the problem, a horizontal well is an alternative approach for the drilling of oil and natural gas in cases where the vertical wells do not yield enough hydrocarbon. The horizontal wells increase the chances of hitting the targets and stimulating the natural gas reservoirs. The horizontal well also increases the area of contact between the rocks and the fluids.

The horizontal well is then completed with multi-stage hydraulic fractures. This will multiple sinks and dramatically reduce the path length the hydrocarbon has to travel in the formation. The method is important in deposits that occur in shale gas and tight gas. The improvements in horizontal drilling and multi-stage hydraulic fracturing are vital in recovering natural gas from the Haynesville shale.

In order to drill a horizontal well, a vertical well must be drilled first. After the well has been sunk into the desired rock formation, the pipe is then removed from the vertical well and a motor connected to a drill bit is lowered into the well. The motor is driven by the flow of the drilling mud down the drilling pipe hence causing the bit to rotate without the rotation of the whole piping system. The drill will bore a route that is differential from the orientation of the drill and the piping system. The bit and the pipe will be lowered into the horizontal well and the bit utilized to create a path that will bend the vertical well to the horizontal well. When the desired curvature (desired angle) is attained, the drilling will resume in the entire in the direction of the horizontal well (Leffler and Raymond, 2015).

Horizontal drilling is three-times as expensive as vertical drilling (Kaiser and Yu, 2011). Even though horizontal drilling is costly, the method is still desirable in the recovery of shale gas because the existence of multiple fractures assures a huge increase in productivity compared to vertical wells, even if the latter are also hydraulically fractured. Some of the most viable wells in Desoto Parish are located below residential areas or parks where footprint on the surface would be unacceptable. The use of horizontal drilling will allow reaching of these areas. The horizontal well can be branched into several paths from the single main well hence reducing the surface presence of the drilling activities. The Horizontal Drilling method has advanced by using the batch drilling technique. The batch drilling technique requires drilling multiple wells simultaneously by adopting the drilling rig skidding system and having it slide over and iterating the same process instead of drilling one well at a time. The extra cost in the drilling is covered in well production as the yield of oil and gas greatly increases.

The Haynesville shale has witnessed its fair share of vertical wells, which was the first to be drilled, completed, and tested during the horizontal drilling process in the gas shales. Although most vertical wells have been sunk in the Haynesville shale, they have been used for data collection and research rather than production. Most of the production is accomplished via horizontal completions. The vertical pilots can either be used to collect cores or logs, but once they finish their functions they are plugged so as to keep off the horizontal leg. The typical Haynesville lateral wellbore measures between 4000 and 4600 feet in length and permit enough fracture in the wellbores (Chesapeake Corporation, 2009). The fracture stimulation is designed in such a way that it permits cluster perforations separated by 300 to 350 feet in a lateral. The Haynesville horizontal wells have at least 10 to 12 fracture stages per well (Browning, Ikonnikova, and Male, 2015). The wells are fracture stimulated with a cemented liner that is either 4 ½ or 5 ½ casing. The wells also permit high enough treating pressure so that fracturing can be accomplished without the need to eliminate the friction in tubulars (Lippes, 2015). Every stage in the horizontal wellbore is treated with about 8000 and 12000 bbls of slick water. Each stage also carries approximately 300000 lbs. of proppant in the play (Agrawal, 2009). The slick water used in the horizontal wellbore contains a gel that purposefully functions to increase the fluid viscosity so that the fractures can be opened and allow the propping agents to be pumped into the fracture (Louisiana Department of Natural Resources, 2017). The proppant pumped into the reservoir in the horizontal wells in Haynesville is a mixture of hydro Prop, ceramic or resin-coated sand. The API mesh size is either 20/40 or 40/70.

Hydraulic fracturing requires a large amount of water. The Carrio-Wilcox aquifer in DeSoto Parish is a low yield aquifer system with physical restrictions. With more drilling activities in this area, the stress on the Wilcox aquifer might increase. The Commissioner of the Office of Conservation recommended the operators to use the available surface water resources such as Red River, or other acceptable alternative water resources for hydraulic fracturing (Louisiana Office of Conservation, 2008).

The normal drilling time for the Haynesville Shale wells is 50 days. There is a two-week delay time that is used for stimulation once the rig has been removed from the location. The wellbore will then be stimulated for four or five days. Once the well is completed its average IP is 6000 MCF/D with a first-year decline of 81%, the decline rate will become lower for nine years until the last value of 7% is attained (Agrawal, 2009).

The Haynesville horizontal wells have an IP of between 5 and 20 MMCF/D with massive decline rates once production commences (Agrawal, 2009). The industry prediction is that these horizontal wells will recover 4.5 to 8.5 BSCF per well. The estimated cost for a single well is between $6.9 and $11 million (Chesapeake Corporation, 2009). The price of the natural gas has been essential to the success of the gas shale in the United States. However, the weakness in the natural gas price has reduced the investment in the shale drilling hence causing uncertainty in the natural gas sector. The operators are also seeking for an alternative for the completion of the wells such as the use of closer perforation clusters, but this method may cause narrower fractures. Narrower fractures are easier to close under stress and limits the amount of fluid passing by. With closer perforation clusters, some fractures might be even inhibited by other fracture and this is called the “Stress Shadowing effect”. As the number of perforation clusters increases in one fracture stages, the problem arises with achieving the same injection rates of proppants. The equal injection rate is important because it is an important indicator of place the equal amount of proppant in each section. This is true especially because we don’t know what’s really going on underground.

1.2 Motivation of Study

No two shales are alike, whether from a general view or near the wellbore region (King, 2010). Compared to other major shale gas plays (Fayetteville, Marcellus, etc.), the Haynesville shale play is deeper, hotter, and has higher pressure. The depth for the formation is around 11,000 to 14,500 ft. The Haynesville shale become deeper as the field is closer to Gulf of Mexico. The temperature for the formation exceeds 300F, and the abnormally high-pressure gradient is around 0.72 – 0.9 psi/ft. Organic materials in the shale create the high pressure as they transform into gas, but still trapped in the reservoir due to the impermeable boundaries. The high gradient pressure leads to porosity, permeability, and movable gas content increment and effective stress decrement. When high temperature and pressure is applied to the dry gas, the gas compressibility might become extreme. Because the Haynesville shale produces dry gas, it does not need preprocessing before being liquefied. In addition, Haynesville shale is softer and more ductile than other major shale gas plays. The softness of the rock is usually represented by Young's modulus. By definition, Young's modulus is the measurement of the resistance of a material to elastic deformation under load. The material with a low Young's modulus value will change its shape considerably after deformation. Haynesville has relatively low Young's modulus value compared with other major shale gas plays, which is between $1.0 * 10^6$ psi and $3.5 * 10^6$. The Haynesville shale also has low permeability, which varies from 100 nd to 500 nd (Thompson 2011). Because of these unique properties, the Haynesville shale play has a relatively higher development cost, making it sensitive to the natural gas price. In recent years, with natural gas price fluctuating and competition increasing globally, operators are constantly under pressure to reduce cost and optimize production. Thus, it is important for operators to evaluate the production and completion methods in the long term.

The sweet gas yield in the shale formation brings not only opportunities and economics benefits, but also uncertainty and challenge. The uncertainty is due to the heterogeneity of the shale formation and the challenge is choosing the most effective, and economical way to produce shale gas. A comprehensive understanding of the field will increase the chance of successfully developing the field with economic viability. It is valuable for the industry to have the study based on the real production data of the gas reservoir rather than theory, laboratory data, and speculation.

Much research has been conducted to explore the possible factors that influence ultimate recovery, but the difference in the results indicate that more analysis is needed. Most researchers use the traditional method of "well based analysis" to figure out the correlation between the completion parameters and the cumulative production. The result normally indicates no or weak correlations.

During typical well-based analysis, the geospatial information regarding the analyzed well and its neighbors is either totally neglected or extremely simplified. The basic hypothesis of this work is that the role of completion parameters can be better understood if detailed geospatial information is used in the analysis.

Our basic approach is area or section-based analysis. By dividing the study area into 1-mi by 1-mi squares (pseudo-sections), we try rigorously account for production coming from the section and completion parameters (total length drilled, proppant amount spent, fracturing fluid used) in the same section. Since the subsurface path of many wells crosses more than one section, we need to assign geo-spatial weight percentages to the well. Using the weighting factors, we then can create a production and completion database organized by sections. The section-based analysis is relatively more difficult than the well based analysis. This is because the approach requires the evaluation of the drainage area of an individual well and most importantly, its percentage distribution among the section involved.

From the other hand, we anticipate that the section-based analysis is more rewarding in the long run because it can shed light on issues such as actual effect of well spacing, total length completed per acre, proppant loading per acre, compared to the same quantities accounted for on a well-by-well basis. We postulate that a section-based analysis will lead to more statistically sound relations reducing the artifacts resulting from ever changes drilling and completion practices, subjective believes, etc.

In addition, the long-term assessment of the completion and production was restricted for past researches because of limited historical data. Recently, a number of researches focusing on effect of completion parameter on cumulative gas performance in the Haynesville shale play has increased on the basis of inferred drainage area. However, few studies examine the completion data of a large population of existing wells. As more wells are put into production and more data are available, the capability to handle the many factors influencing productivity and ultimate recovery is continuously improving.

While it seems that operators tend to use more proppant to boost the production in the Haynesville shale play, there is a void of academic literature to prove the relationship between this key completion parameter and production. There is some literature study regarding the relationship of proppant usage and the cumulative production in Haynesville shale play, but it is from the well by well analysis and the results are not from the spatial perspective.

Geospatial analysis is a significant tool in the petroleum industry. There is a need for more study on the topic. Most of the time, engineers use geospatial analysis to make stochastic reservoir models. Similar ideas could be applied to examine production and completion parameters. This analysis may reveal potentially geologic factors that greatly influence the results, or on the contrary, can prove that reservoir quality is basically uniform in the study area.

The aim of this study is to provide new information for operators to facilitate better understanding of Haynesville shale production and make wise decisions better accommodating the ever-changing gas price environment.

1.3 Objectives

The objectives of this study are to:

- Identify the production and completion method used in the DeSoto Parish
- Analyze the production and completion dataset of the DeSoto Parish on a section-by-section basis and determine the effect of completion parameter on cumulative production

- To provide tools for optimum field development parameters (such as well spacing, proppant loading, cluster spacing, etc.) corresponding to given natural gas price environment.

CHAPTER II

LITERATURE REVIEW

2.1 Life Cycles of a Gas Well

The Louisiana Oil and Gas association (LOGA) identifies five stages of a gas well: staking the well, drilling, completion, production, and reclamation, as shown in **Fig. 4**.

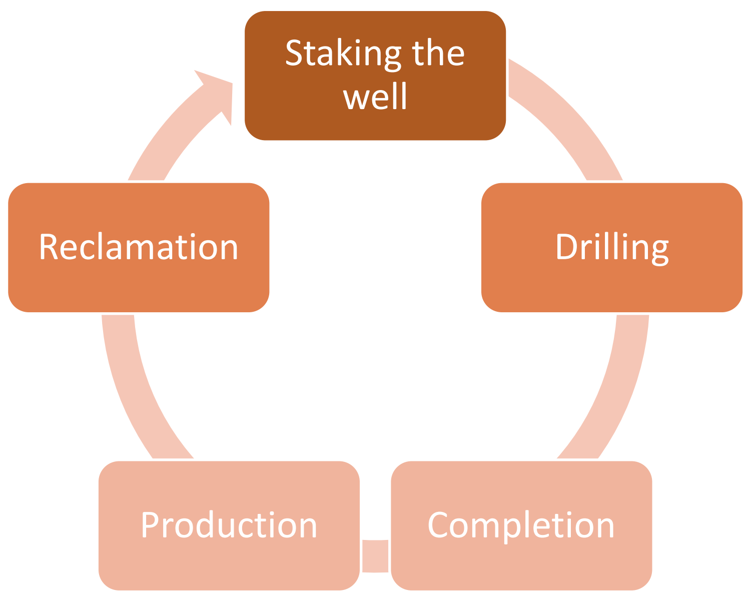

Figure 4. Life cycle of a gas well based on Louisiana oil and gas association (LOGA)

During the well-skating stage, engineers, geologists and land negotiators, landowners, and other interested parties work together to determine the optimal location for the well. Drilling under private property requires permission. A leasing order to drill the land requires surface rights, mineral rights, unitization of wells, forced pooling, property, and land rights, etc. Petroleum companies need to get all the required documents before drilling a well.

Next, the drilling process of a gas well includes preparation, surface casing and cementing, data logging, and production casing. In the preparation stage, an operator will spend approximately one week setting up a pad site with approximately 300 feet by 300 feet size for placing the drilling rigs. The operator will use a blowout preventer under the rig floor to protect the wellbore during drilling, which consists of hydraulic valves. Afterward, the surface hole was drilled with cement pumped down and circulates back to seal the space between casing string and wellbore. Then, the engineer will send logging equipment downhole to analysis the properties of the rocks and will identify the targeting formation. After that, the production casing string is placed in the hole. A further cementing job is required to ensure the proper production of gas.

Furthermore, the completion process consists of three steps: casing perforation, well fracturing, and drilling out plugs and natural flow back. A perforation tool with cylindrical shape and powerful jet charges are lowered to the target formation, penetrating and cementing the steel production casing. The perforation area allows gas to flow from the reservoir to well. Then hydraulic fracturing is used to increase the gas flow. Hydraulic fracturing involves pumping fluid and proppant at high pressure to create long and narrow fractures as a pathway for gas. Before fracturing, temporary bridge plugs are used between each stages of fractures. After fracturing, gas will flow naturally through a small rig drills through the plugs, to the perforation, in the steel casing, and up to the surface. In the beginning, the production includes some water plug material, and gas. Some water will be reprocessed while the other water will be disposed.

The production stage covers the liquid and gas separation process. Natural gas extracting from the well is composed of a mix of different components, which require multiple stages of separation. After the gas has been separated from the produced water and any hydrocarbon liquids, it will be transported through pipeline to a compressor facility, treatment plant or disposed by truck.

The final stage is the Reclamation. During the whole process of gas well development, operators are required to minimize the influence on the environment. When drilling and completion is finished, the operator will remove all fluids and either reuse or dispose the fluids. Then they will fence the drill site. The data of the developed gas well and the associated geological and petrophysical formation is collected and will be used for the future well development plan.

2.2 Previous Researches on Haynesville Shale

Since 2008, in the process of development, there has been a lot of research results and literature in unconventional resources. Literature that is related to this topic is significant for having an insight about the study area. OnePetro was very useful petroleum website to locate the related studies, although there is obvious lack of study related directly to the geospatial analysis of the Haynesville shale. The good news is that there exists some literature about using statistical analysis of Haynesville shale and oceans of literature regarding the development of the Haynesville shale from various perspectives. In addition, there exists some geospatial studies that is used in other shale play, such as Barnett shale that we could adopt as a reference for this study.

Halliburton (2010) presented the potential challenges associated with development of the Haynesville shale in regards to drilling, hydraulic fracturing, water resources, and environmental issues. As mentioned before, Haynesville shale is hot, deep, soft, and has high pressure. As the drill pipe goes deeper, the uncertainty increases and the drill bits lifetime will be shortened with increasing rock hardness. Additionally, the casing placement and cuttings removal process will be hard in the drilling process. Because of Haynesville's soft characteristic, the hydraulic fracture work could create wider aperture width with lower pump pressures, but it may be troublesome to make the fracture deeper into the formation. As a result, it requires more hydraulic horsepower and more advanced proppant fluid. The softness of the formation, along with high closure stress gradient and low permeability, requires a large amount of proppant loading. The high proppant volume compensates for fracture width loss caused by proppant embedment. It is important to identify every part of a well with special stimulation treatment. The primary environmental concern of Haynesville shale is in relation to water and the access of this commodity. Horizontal drilling has increased access to areas that were initially not tapped into thus increasing the distribution of the wells. These wells may cause disturbance to these areas during the drilling process (Lippes, 2015). The horizontal drilling increases the possibility of contaminating the existing water reservoirs. The large water requirement might cause some water conservation and disposal issue.

Pope et al. (2009) found there exists a relationship between completion practice and production performance in the early stage. Modeland et al. (2011) performed a statistical analysis of the effects of completion parameters on production of the Haynesville shale. The study analyzed production profile of 286 wells. The result of this research indicates that well location, number of fracture stages, and proppant concentration and placement has greatly influenced Haynesville production. Another key point from this study is that greater number of clusters will lead to increasing uncertainty regarding the placement of the proppant and fluid. On the other hand, if an operator chooses to have less distance between perforation clusters, the operator needs to have more fracturing stages to create the same amount of fractures in the same lateral length. To do so, the operator need to find a balance because the completion time will increase unless some area of the wellbore is intently sacrificed.

Sahai et al. (2012) conducted a well optimization study to determine the optimum number of wells for infill drilling of Haynesville shale in 2012. The study analyzed the production performance of more than 100 wells in Haynesville shale. The results determine the optimal is 5 wells per section. However, their study only focused from the drilling perspective. There is less influence of drilling techniques on production compared to that of completion techniques when a well has produced for years.

2.3 Study Area

The heart of the play, the sweet spot, is located in Desoto Parish in North Louisiana stretching approximately 900 square Miles. DeSoto Parish has quite a bit of activities, around 22 rigs were put up and 10 of them are associated with the Haynesville shale wells. The production level is high in the area. This study focuses on the core region in Haynesville shale because it best represents the behavior of the Haynesville shale. By definition, the core region is the developed area that is continuously expanding. Desoto Parish is a good representative.

Desoto Parish is positioned in the submarine region. The porosity of the Haynesville shale is about 6-15% with an average of 12 % in the producing regions. The porosity is relatively higher than other shales, which means that it will contain relatively more gas than other shales. While the gas porosity in the 12% region is between 5 to 11 %. Shale Gas contains both free gas and adsorbed gas. The gas porosity is considered for the free gas in the pores and the natural fractures in the rocks. The adsorbed gas accounts for a considerable amount of the total gas. The high pressure and the depth of the Haynesville shale reduce the possibility of the adsorbed gas being tapped anytime soon. (Magner and Wren, 2008). The depth of the Haynesville shale will only allow the extraction of the free gas using the current production technology. Therefore, the volume of the free gas rather than the adsorbed gas determines the recovery of the natural gas. The gas porosity, in this case, is oblivious of the adsorbed gas.

Browning et al (2015) analysis the production data from all Haynesville wells drilled from 2008 to 2012 and create porosity-thickness map. Younes et al (2011) further plot the TOC distribution for the entire Haynesville field in **Fig.6**. As seen in **Fig. 5**, the porosity thickness is around 10 to 16 ft and the most prolific area is the DeSoto Parish. The TOC (Total Organic Content) ranges between 3.1 and 3.4 in DeSoto Parish. High TOC allows kerogen to have a strong adsorption and high gas in the formation. Less clay content in this area makes the hydraulic fracturing easier than the area in the north because there is relatively less chance for proppant embedment and fracture conductivity loss. The research has estimated the presence of the lower end of the spectrum in the shale. The organic materials in the Haynesville are terrestrial plant debris of Type III kerogen (Magner and Wren). Between 2 to 10% of the rock volume is occupied by the large fossils, such as the textularid-type foraminifera, that tends to collect together. The filaments of organic materials have also been found in the samples contained in the basin.

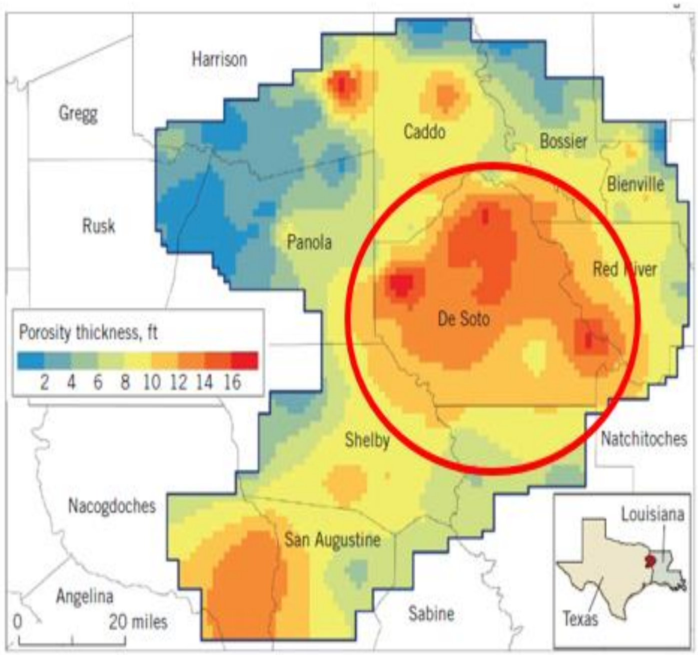

Figure 5. Haynesville shale Porosity-Thickness Map (Browning et al, 2015)

The targeting study well type will be horizontal wells and directional wells. By considering all the gas wells in Desoto Parish Haynesville formation, we find that horizontal and directional wells accounted for 98% of the wells in DeSoto Parish as observed in **Fig. 7**. It is clear that horizontal and directional wells are the primary choices of the operators in dealing with the shale gas. On the other hand, the horizontal and directional wells perform better in this area. In the future, we expected that more horizontal wells and possibly the multilateral wells.

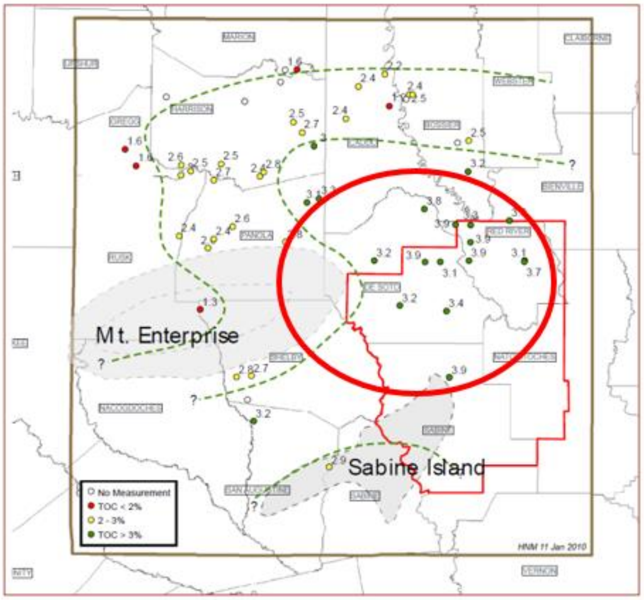

Figure 6. TOC distribution plot of Haynesville gas shale (Younes, et al., 2011)

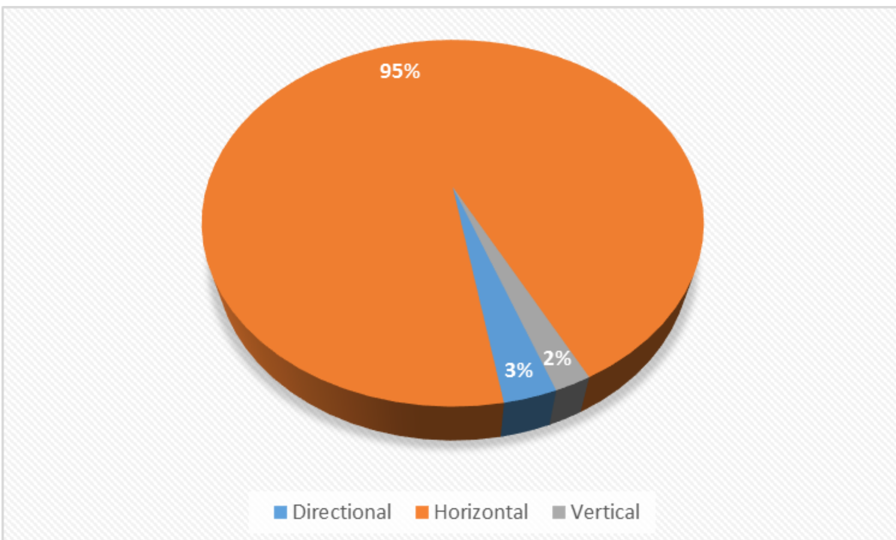

Figure 7. Well Type Distribution in DeSoto Parish

2.4 Geologic Setting

The Haynesville shale is a heterogeneous formation composed of organic and carbonate rich mudstone. The Haynesville shale was deposited during the upper Jurassic period, which is about 150 million years ago, in a deep-water marine environment. The deposition of the Haynesville Shale occurred when sediments that formed the shale flowed in from the North and Northeast rivers (Magner and Wren). Geological evidence put a lagoon and the time of the deposition process in the region where the Haynesville shale is present. The Haynesville deposition and carbonate shoals surrounded the deposits of the organic matter that was contained in the basin. The deposition of the fine grain sand and the silt took place sequentially across the marine slope into the basin environment over a long period leading to the formation of a thick Haynesville Shale, which has blanketed a large area. The Bossier shale sits on the Haynesville shale, hence the debate to consider the Bossier shale part of the Haynesville shale has been around for a while (Magner and Wren, 2008). The Haynesville shale overlies the Smackover Limestone and underlies the sandy shales of Bossier formation. Because of the close proximity and the same origin of deposition of Bossier shale and Haynesville shale, some people called the area the Bossier-Haynesville shale. To be clear, this study only focuses on the Haynesville shale part in North Louisiana, not the Bossier part.

The Haynesville shale gas play covers close to 9,000 square miles from the East Texas Salt Basin to the North Louisiana Salt Basin, as shown in **Fig. 8**. The Haynesville shale formation greatly exemplified the marine transgression systems tract, which causes the deposition of marine shales in sequence. The bumpy depositional surface engendered various thickness of salt deposition. The geological strata, Sabine Uplift, influence the Haynesville formation regional depth by 10,000 ft in the northeast and 15,000 ft in the west and south. A few streams run over the Haynesville shale basin containing sand and mud. (Hammes et al, 2011). The high mineralogy content in the fluid flow caused the cementation of the most natural fractures, so the natural fracture cannot contribute to the productivity of the well without reactivation (Buller and Dix, 2009). In addition, the mineralogy for this area is also different from north to south. The north or northwest part of the play contains more clay and siliciclastic, while the south or southwest of the play contains more carbonate content and higher TOC (Spain and Anderson, 2010). Agrawal reports that the mineralogy of the Haynesville shale is made of quartz and mudstones, i.e., mostly made of clay. The quartz is in a considerable amount of between 28 and 33%. This percentage of quartz is not definite but varies leading to the formation of the sweet spots on the Haynesville. Clay is the second most abundant materials in the Haynesville shale making 25 to 33% (Agrawal, 2009). Other minerals that occur in a significant amount are dolomite, calcite, pyrite, feldspar, and siderite (Goddard et al, 2009).

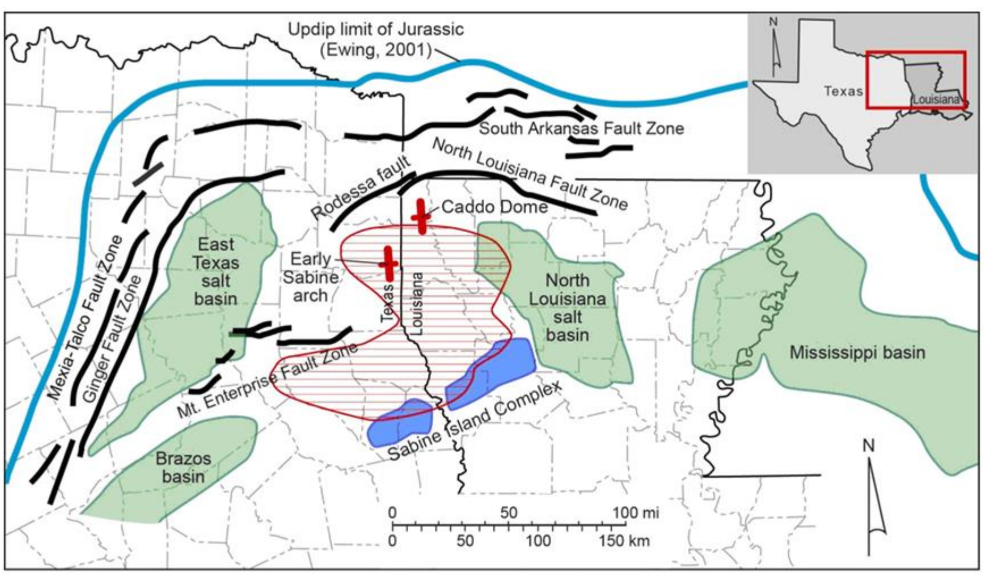

Figure 8. A structure map of the Upper Jurassic northeastern Gulf of Mexico basin, with shaded area represent the productive Haynesville gas shale (Hammes et al, 2011)

2.5 PLSS (Public Land Survey System)

The biggest problem to analyze the shale is the heterogeneity of the reservoir. The most effective way to solve this problem is by dividing the accessed area into small cells and assume that the geology is locally homogenous. In this spatial study, the public land survey system (PLSS) is a good tool to evaluate drainage area for horizontal wells.

The PLSS has a long history of use. After the American Revolution, the federal government amassed an enormous war debt. To pay for the debt, the government came up with the idea to transfer proprietorship from public domain to private domain. There was a need to survey the land (White, 1926). The previous commonly used measuring method is Metes and Bounds. This method uses obvious landmarks like rivers, lakes, roads, and constructions to identify the land boundary. This method has an obvious defect. The destruction of some obvious landmarks with time will cause difficulty in identify the land boundary. The Land Ordinance of 1785 proposed the Rectangular Survey System as the juridical, economical and easy method to divide the statehood into small rectangles. The law stated that land would be divided into 6-mile by 6-mile rectangles, which is identified by townships. The townships are composed of range number and township number. Township number is just how many cells north or south to the reference point and the range number is how many cells west or east to the reference point. The rectangle identified by township is further subdivided into 36 sections, with 640 acres (1-mile square) for each section (Avery & Burkhart, 1994).

The Google Earth software indicates that the township of Desoto area varies from 10 to 16 north and the range is around 10 to 16 west. As noted, some areas do not fit into the PLSS system. This is because those undefined zones are located in the colonial grant land, which occurred in several place in LA. The PLSS coordinates are incompatible with most petroleum software. Past research requires the USGS geographic coordinates data and loading in the software like ArcGIS.

PLSS has been used in several shale studies and prove to work well in the major shale plays (Barnett, Fayetteville, and Marcellus, etc.). This study follows some similar workflow to that in Browning et al (2013) and Browning et al (2014), which create tier map for Barnett shale and Fayetteville shale correspondingly. They used the production histories to forecast production and use tier well acreage to build well inventories. Andrew Avalos (2016) used the PLSS to investigate the Haynesville shale. However, he assigned wells to a given section based on the location of the wellhead. His study did not consider that horizonal well may partly drain other sections as well, not only the one where the well-head is located.

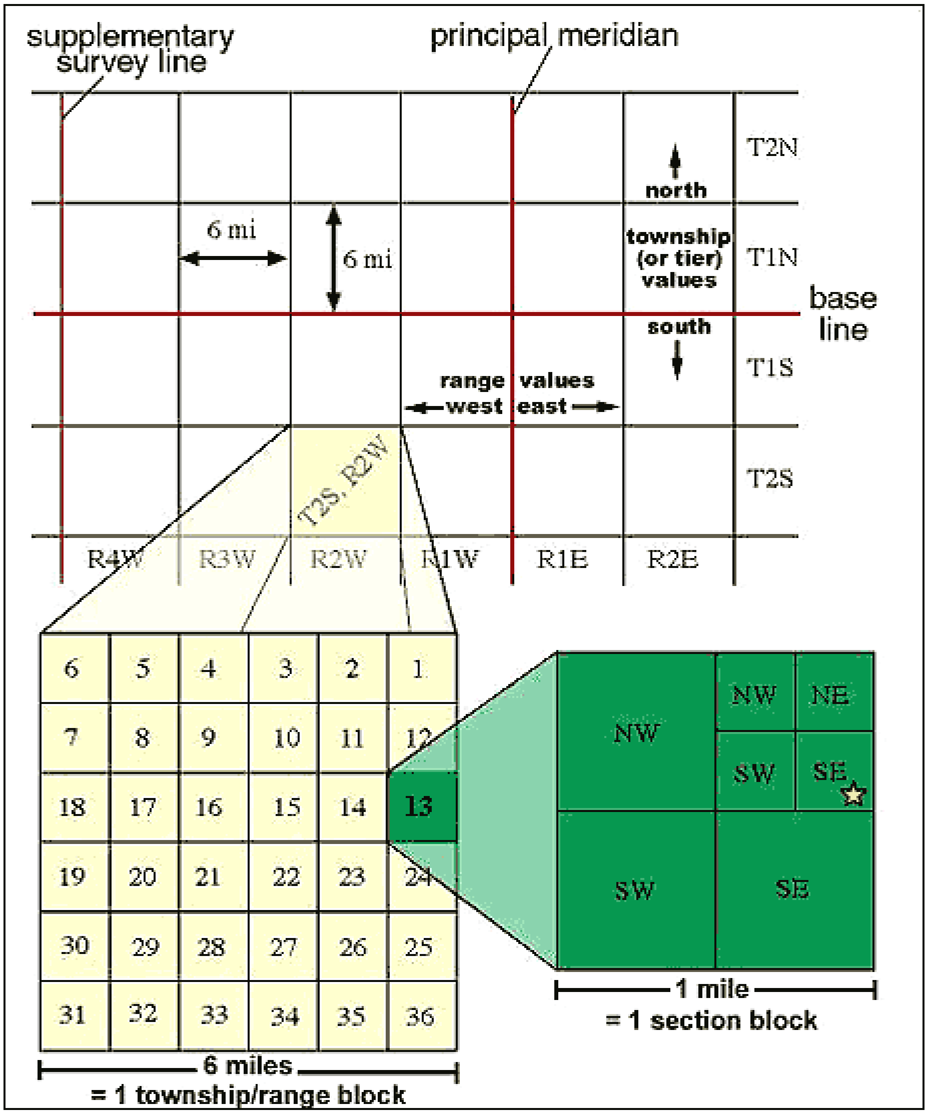

Figure 9. Demonstration of the Basic PLSS Coordinates (Jim Riesterer et al, 2008)

CHAPTER III

DATA AND METHODS

3.1 Data Availability and Pre-Processing

Available data to the author includes the production data and well information from Drillinginfo, a commercial platform that provided the petroleum-related database. This data is very important in this assessment, otherwise the analysis is not possible. The study queries were performed to remove any vertical wells, the wells outside the Desoto Parish, and the wells target on other formations because this study is confined to horizontal or directional wells only in Desoto Parish Haynesville shale. The database compiles 1560 drilled Haynesville shale gas wells in DeSoto Parish with different well statuses, such as active, inactive, shut-in, expired permit, and P&A (Plugging and abandon). Dry holes, on the other hand, are not included in the well totals since the drilled wells are dry and have no production.

The completion related data of 272 wells in 70 sections was collected by previous graduate student Andrew Avalos. However, not all wells out of 272 wells located in the DeSoto Parish and most of them were filtered out. One important completion factor is the fluid usage, which influences the ability to deliver sand to fractures and the pressure applied to source rock. Another important completion factor to use is the proppant usage. Those two factors might have great impact on well productivity. We collected more completion data from the FracFocus database, a hydraulic fracturing chemical registry website used by industry for reference materials used to fracture wells. Every well drilled in the United States is assigned with a unique and permanent API number. The API number consists of 10 digits. The first two digits are the state code. The following three digits are the county code. The last five digits are unique numbers to identify the well. The API number is the intermediate that connected the data from all the sources that we have. There are some duplicated well in the FracFocus database and the proppant amounts are almost the same, so we delete the repeated data.

Many data were missing even after updating for various reason. Although it’s impossible to figure out if the existing number is accurate, this is the only completion data that is publicly available and some of the data could be verified using information from various sources.

The average development time of the field is 1 to 2 years. The first finding of Haynesville shale is at the end of 2007. It is reasonable to set the 2010 – 2018 timeframe as the study period. The data acquisition has a financial cost; thus, we only collected the data provide particular benefits for our research. Moreover, among the collected data, not all the information is relevant to the current studies. Of all the available variables, **Table 1** indicates all the selected variables to achieve the final research goal.

The data were imported into Wolfram Mathematica, a commercial software use the interactive notebook to combing text, code, and figures together. Mathematica has the geological feature that allows users to visualize data in the map easily by inputting a county name. We used this application to import the city name, longitude and latitude so that we could match the coordinates of the wells. This software avoids loading and processing large number of coordinates data in the shape file. As a widely used software in most universities, Mathematica might save lot of time for researchers when dealing with geo-spatial studies like this.

Table 1. Useful Data Variables

API10STR	TotalProppant(First)	TotalFluid(First)	TotalWater(First)
TotalAdditive(First)	StartDate(First)	EndDate(First)	Qualifier(First)
TreatmentJobCount	StageCount(First)	MaxInjectionPressure(First)	PerforatedIntervalLength
MaxInjectionRate(First)	WellName	WellNumber	LeaseName
OperatorAlias	ReportedOperator	Field	County/Parish
KBElevation	GroundElevation	MeasuredDepth(TD)	TrueVerticalDepth
ProductionType	WellStatus	SpudDate	CompletionDate
DrillType	UpperPerforation	LowerPerforation	HorizontalLength
WellboreCount	CompletionCount	FirstProdDate	FirstTestGasVolume
FirstTestOilVolume	FirstTestWaterVolume	FirstTestHoursTested	FirstTestProductionMethod
FirstWellTestDate	FirstTestType	LastWellTestDate	LastTestType
FirstTestGasGravity	FirstTestOilGravity	FirstTestGOR	FirstTestCasingPressure
FirstTestChokeSize	FirstTestFlowingTubingPressure	PeakBOE	PeakGas
PeakOil	CumBOE	CumGas	CumOil
CumWater	Section	Township	Range
SurfaceHoleLatitude	SurfaceHoleLongitude	BottomHoleLatitude	BottomHoleLongitude

3.2 Well Selection Criteria

Like any other database, the data in the DrillingInfo is report monthly by different operators, which is subject to error. Some wells have obvious questionable data. For example, the smaller value of cumulative gas than the value of peak gas. In that case, we perform the data quality control and set up the criteria to select the effective data. The obvious erroneous data and outliers are deleted. The well selection criteria is as following:

(1) Drill Type is either horizontal or directional. Because we also filtered the download data, this is just used as an additional check. All the data satisfy with this criterion. In the dataset, 1515 wells are horizontal wells and 45 wells are directional wells.

(2) Cumulative gas is greater than the peak gas. By this criteria, 46 data were not satisfied.

(3) Gross perforated interval is greater than 1000 ft. The perforated interval is the part of net pay that allows the fluid to flow into the wellbore.

(4) Gross perforated interval is less than horizontal length. This is to ensure that wells have effective perforations.

(5) The well has monthly production history. Some of the wells have well information, but they either not document with the production history or too young to even have established a production history.

(6) The absolute difference between surface and bottom latitude and longitude are greater than 0.001 respectively. This criterion is intended to have the horizontal well with larger lateral length. Otherwise, it is very difficult to calculate the geo-distance. This criterion is very rigorous and most of the data were filtered out by this criterion. If we change the decimal point of the threshold number, the dataset will be different and the final results might change.

The criteria are very strict in the study. As a result, out of 1560 wells, only 433 wells are considered as high-quality data set. More than 50% of the data is filtered out and will not be take into the later analysis. Another point we noticed that some horizontal well length reported for the high-quality data set is different from the calculated horizontal well length by using the geo-coordinates data. The geo-coordinates data are assumed more reliable than the well length data. Thus, we use the calculated well length in the later analysis.

3.3 Data Analysis by Location

The method applied in this project is statistical in nature. The main part associates with examining the correlation of proppant loading and fracture fluid with cumulative gas. This research requires aided with maps that show the location of wells used for the correlation. In most cases, the well locations refer to wellhead location. The wellhead location is accurate to depict the center of the well path of vertical wells. However, using the wellhead head location is not suitable to portray the center of well path of horizontal wells because horizontal well will extend to thousand miles away. Thus, we believe the better criteria to use is the middle section of the horizontal well. In this case, with the given surface longitude and latitude of the beginning and end of each horizontal well lateral segment, the author was able to calculate the middle point latitude and longitude. Then, the coordinates are translated into the PLSS section. Later, we will integrate the production data for each section and create a tier map.

As stated earlier, the colonial grant land leads to many undefined areas with no TRS value in LA. Thus, we proposed to use the "Pseudo-TRS" system because what matter to us the most is not how much gas coming from each section rather than the actual definition of the area. The "Pseudo-TRS" system was calculated by using the geological feature of Mathematica. By calculation, when any random location moved 1 mile to the North in Desoto Parish, the latitude will change about 0.014532. When the location moved 1 mile to the West in Desoto Parish, the longitude will change 0.017033. In that way, the base section "09N10W01" is identified. Then other section boundary was identified follow the rules of the PLSS system for 6 miles by 6 miles to get the township and range and 1 miles by 1 miles to get the section number. Most of the time, the "Pseudo-TRS" will be the same as the standard PLSS system with minor inaccuracy exists near the boundary. The sections with 1 * 1 mile (640 acre) are referred to as *Pseudo-sections*. For each Pseudo section, there are two types: drilled or partially drilled section with at least one well exists, and undrilled section. The undrilled section is the ideal acreage that can be drilled in the future in our study not only because we use high quality dataset after filtering, but also because the development difficulty. The development difficulty includes but not limited to the colonial reserve area, the surface hindrance, and the faulting. In reality, only part of the ideal acreage can be developed.

3.4 Estimated Ultimate Recovery (EUR)

After that, we tried to determine the estimated ultimate recovery (EUR) for individual horizontal well and grouped the data by Pseudo-sections. The ultimate recovery is how much a well could produce before it reaches the economic limit or the average expected lifetime of a well. Petroleum engineers use several techniques to forecast future production and calculate the ultimate recovery. The widely known method in the industry is the decline curve analysis (DCA). Decline curve analysis founded on past experience and observations. The basic idea of the decline curve analysis is to represent the past performance with mathematical curve and equation. Then the known trend is used to make the future prediction. The input parameters for decline curves include the initial production rate, initial decline rate, and the degree of curvature (b-factor). The initial production rate and initial decline rate is covered in the high-quality dataset. The b-factor could be evaluated by fitting the predicted curves to historical data.

In this study, we choose two types of decline curves that works well in shale gas to calculate EUR: the rate-time curve and the rate-cumulative production curve. The rate-time curve is plotted on a semi-logarithmic plot of the monthly production rate and time in month. The rate time curve is further categorized in exponential decline curve, hyperbolic decline curve, and harmonic decline curve. The rate-cumulative production curve is by plotting the production rate verses the cumulative production. The curve will be declined until it reaches the zero flowrate, which means the well doesn’t produce anymore.

Both analysis requires wells to have sufficient past production data to make the reasonable match because the longer past performance could greatly increase the accuracy to predict the future production. The data we collected includes monthly production data for most well has more than 24 months. However, there exists some young well with production data of 4 month only, so the production history is not sufficiently long enough. In this case, we will present one selected relatively old well and one relatively young well with at least 24 month data. In addition, we assume that operational of the field is the same as the past in the future. We decline the entire wells in the high-quality dataset with the production to determine the calculated EUR and the corresponding well recovery of each well. The well recovery will be calculated by use the current cumulative production divided by the calculated EUR. We then compare the results of the EUR calculate by the different methods and the actual production.

The problem of well-based EUR calculation is that the effect of opening or closing other wells in the same section will very much distort the analysis. This bias (un-consistency) remains even if the method of weighted EUR is used to obtain the EUR for the whole section. Since EUR is just a measure of the value of the well-completion entity associated with the section, we have other options to characterize this value as well. For instance, if we can conclude that the given section has already produced an overwhelming fraction of its EUR, corresponding to the current configuration of well-completions, we can just use the current cumulative production from the section as the measure of the value. Such a characterization is quite reliable and can help to avoid conclusions introduced by artifacts of the applied method of calculating EURs.

3.5 Assigning wells to Pseudo-sections

In this section, the wells were assigned to Pseudo-sections based on three approaches: (1) Using well head location, (2) Using middle point of the well location, (3) Calculating weighting factors based on complete subsurface well path. Assigning horizontal wells to Pseudo section later will allow us to calculate the proportional production and fracturing fluid data to create a tier map.

I first continue Andrew Avalos's study by assigning wells to Pseudo-sections based on wellhead location. Each well has the associated proppant and fracturing fluid with the PLSS section, provided in the Drillinginfo database. I translated the PLSS sections into the Pseudo-sections. For each section, the well path is ignored and the well contributed full to the section. Then I did the similar process by using the middle section of the well location.

The weighted map is what distinguish this study from previous studies. Based on the lateral length of individual horizontal well, we tried to determine if the horizontal well belongs to one or several Pseudo sections. Past research indicated that rectangular drainage area of fractured horizontal wells is the correct choice in tight gas reservoir. Thus, it is reasonable to assume the rectangular pattern in shale gas reservoir. In this study, each Pseudo-section represents the drainage area of a well. For the reservoir with multi-fractured horizontal well, there are usually two parts: the stimulated reservoir volume (SRV) and the drainage beyond SRV. By definition, the SRV is the part of the reservoir that is effectively stimulated by the hydraulic fractures. Several literatures have indicated that the part of reservoir beyond SRV region does not have obvious impact on the production of a well for extremely low permeability shale (Bello and Wattenbarger 2008; Carlson and Mercer 1989; Fisher et al. 2004; Mayerhofer et al, 2005, 2006; Maxwell et al. 2009; Medeiros et al. 2008; Ozkan et al. 2011). It is therefore reasonable to focus only on the SRV region. There is no way to have a precise well drainage area because what happens underground is uncertain. For the SRV region, people usually assume the length of the horizontal section as the lateral boundary. However, just to be safe, we add additional 100 ft to each side of the horizontal well length to cover the possible minor effect. For the purpose of determining weighting factors, we also assume that the well path half width is 400 feet. This number is referred to the common fracture width based on experience.

Then, we assigned wells to the Pseudo-section. The horizontal wells are likely to be assigned to several Pseudo-sections depending on the overall lateral extent. We first identified neighborhood Pseudo-sections around each center of the wells. We then calculate the percentage of a well that belongs to one or more Pseudo-sections through dividing the well area in the Pseudo-section by the Pseudo-section area. After that, we combined the production data, well count data, proppant and fracturing fluid data to create several tier maps. Later, we will integrate the estimated ultimate recovery (EUR) to create a EUR tier map. Visualizing the data on a map gives the analysis a clear view in spatial dimension.

The map cannot use the cumulative gas and proppant value directly because the lateral length and the location of the well greatly influences the factor distribution. Therefore, we multiply the cumulative gas and proppant by the percentage of a well in the corresponding Pseudo-sections as we calculated previously. We named the new section-based data as weighted proppant or weight cumulative gas. With the aid of the visual map, we have capability of finding if there exists some correlation between two variables.

In this analysis, linear regression model was adopted to model gas production rate, proppant loading, and fluid loading. As seen from the study area introduction in the previous section, the study area in our cases was less heterogeneous because of the proximation in space. The reservoirs properties didn't vary too much across the reservoir space. The linear correlations should work fairly well. The correlation coefficient has the range of -1 to 1 with -1 being a perfect negative correlation, 0 being no linear correlation, and 1 being a perfect positive correlation. The positive number indicates positive correlation and vice versa. The number with absolute value close to 0.3 means a weak downhill or uphill linear relationship. The number with absolute value close to 0.5 means a moderate downhill or uphill linear relationship. The number with absolute value close to 0.7 means a strong downhill or uphill linear relationship (Cline 2009 (a)). Unfortunately, outliers due to data errors can substantially decrease the absolute value of the correlation coefficient and hence quality control is a key to obtain meaningful information.

CHAPTER IV

RESULTS

In this section, we will present several results by investigating different comparison groups in the map form. We will first investigate how many new wells are drilled and characterize the overall production profile in DeSoto Parish wells. After that, we will investigate the EUR of new and old wells in DeSoto Parish. We will present section analysis data first based on well assignment corresponding to the location of the wellhead and mid-point of wells. Then, we will construct weighted maps based on geo-spatial weighting factors. Comparing maps and correlations relying only on wellhead locations with weighted maps allows us to draw conclusions regarding the additional information revealed by the more rigorous accounting for the actual well path. Lastly, we will show the results of handling the missing data by statistical analysis.

The high-quality data was first grouped by first production date, as shown in **Fig. 10**. For this dry gas reservoir, few oil liquids, but large water is produced. By observing the monthly production data from 2012 to 2014, although gas prices in Louisiana increases, the shale gas production and water production experience a 50% decrease. In the later year, the gas production remains a steady production while the water and oil production increase noticeably. We also noticed that the number of new wells that were put into production were decreasing as time passed by except a small increase last year. This trend can be attributed to the negative influence of the prices of natural gas in the period of investigation. But, from an analysis point of view, the same trend has positive effect: it allows us to use cumulative production from a section as quite reliable indicator of the value of the total completion system belonging to the given section, because it means that the overwhelming part of the production is already behind us.

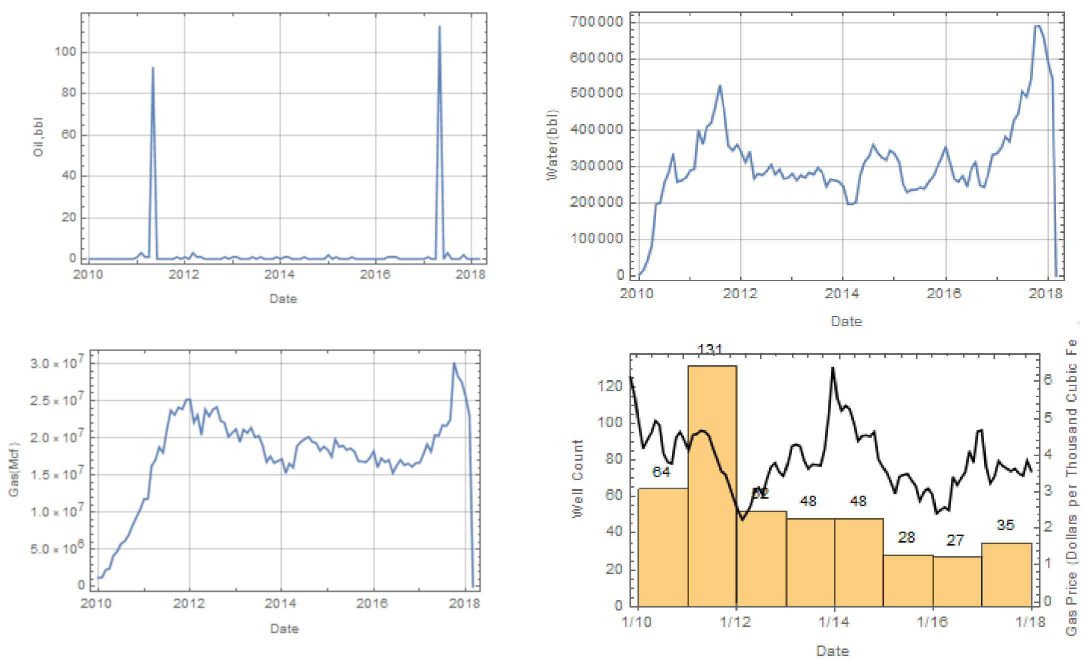

Figure 10. Field Production and Well Count vs. First Production Date

We notice that around 62 wells started to produce within the last two years and they will lead to problems in EUR estimation because the short production profiles available are insufficient for decline curve analysis. The natural gas price data comes from the EIA's document of Louisiana natural gas price. Note that even with the recent natural gas prices increase, the number of new Haynesville shale wells in DeSoto Parish is still very low compared to the peak in 2011. This shows that the industry was under a great recession in 2016 and was still in the process of recovery starting in 2017. This obviously impacts the operators' strategy of spending their resources. In recent years, DeSoto Parish might not be the primary area of development for the operator involved, since other more beneficial shale gas plays have been explored in the last couple of years.

We created the dynamic cumulative production tier map, as shown in **Fig. 11**. The "ToolTip", a dynamic Mathematica function that displays the related information when the mouse points at specific location, could view the detailed TRS information and production information. The color bubble is related to the cumulative gas production value, except the black bubble. The bubble with same color will have the similar amount of gas produced. The black bubble represents the edge of the Pseudo PLSS Township and Range and each small box is the Pseudo PLSS Section, as discussed in the previous section. The arrow in the graph shows the lateral length of the horizontal well. Through the map, user can easily identify the area with high or low production, the well path of the horizontal or directional, the drilled and undrilled block, and the well density. The clusters of wells are found in the north of Desoto Parish. The distribution of the cluster has similar variation tendency as the porosity thickness map. This plot is made as the base graph to check if we make the correct calculation by comparing the trend.

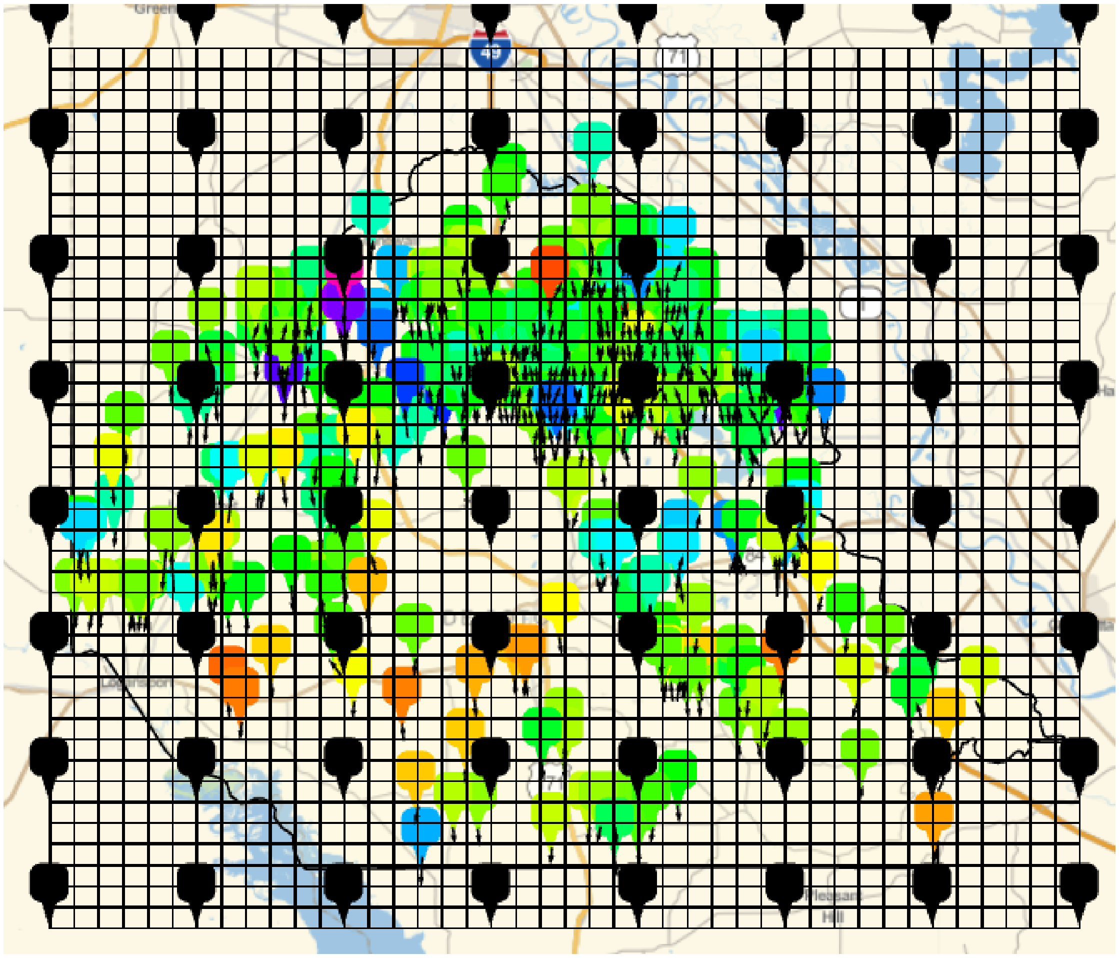

Figure 11. Section Distribution of cumulative production in Desoto Parish: The colors correspond to amount of gas produced based on location

We then did the decline curve analysis of wells. In this paper, we presents a relatively old well and a relatively young well. The representative old well we selected has production data from February 1st, 2010 to February 1st, 2018, exactly 8 years production. The history matches for the selected old well is shown in **Fig. 12 – 14**. The calculated EUR using the exponential method is about 6.61 BSCF. The calculated EUR is estimated conservatively and is at the point where the flow rate reach to zero. In addition, the calculated EUR is not estimated by the full production history because we note that the prediction deviated in the late time. From the gas rate plot, we note that there exists a jump in production rate around 28 months. We use the 28 months as a new start to make the exponential decline curves. There also exists a jump in gas flow rate at the beginning, however, this point has little effect on the estimation because the history is long enough. Including whole well history will lead to underestimate of the well EUR. The new analysis fit cumulative production very well.

The rate-cumulative method produced a EUR of 6.64 BSCF by quadratic analysis. EUR calculated would be the predicted minimum in the future. Normally, for exponential decline, the rate-cumulative data forms a straight line if rate time plot show a straight line on semi-logarithmic graphic pater. In our case, a curvature exists and it fits better by using quadratic fit. The two methods generate very close EUR. The rate-cumulative method has an advantage over rate-time method because the interruptions won’t affect the coordinates. In our case, the two jumps don’t seem to have severe impact. Almost 98% of the well’s EUR has been already recovered. In such a case, the current cumulative gas production is a very good representative for the total value of the completion system.

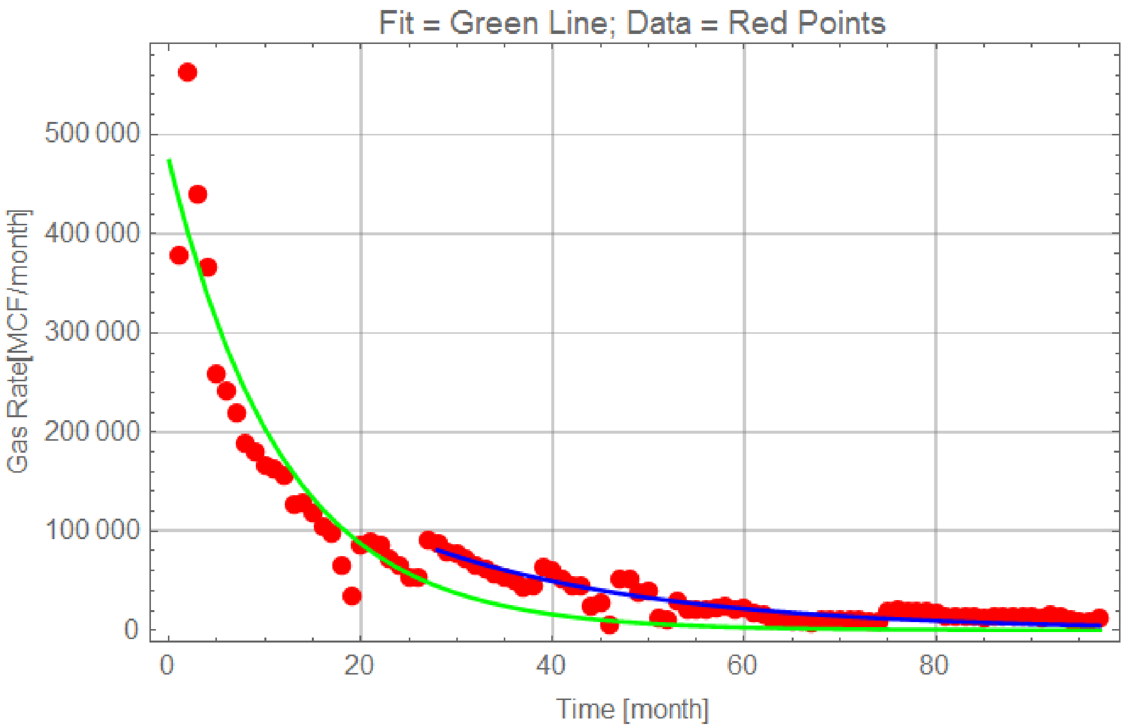

Figure 12. Selected Old Well Exponential Decline Curve Analysis History Match

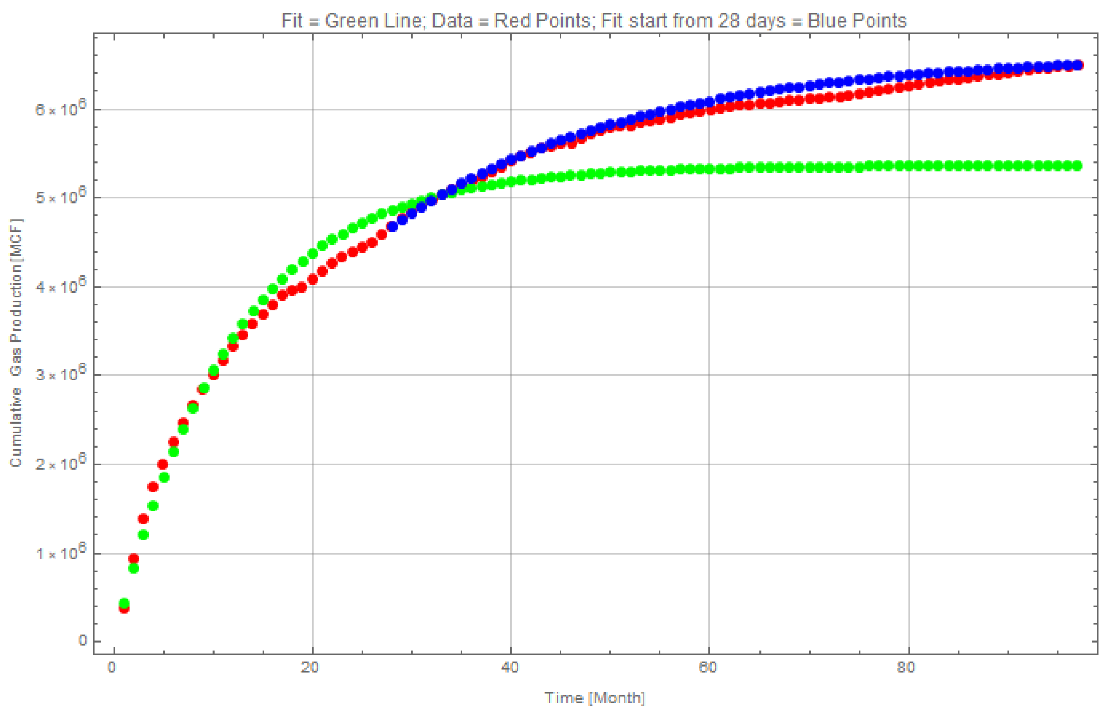

Figure 13. Selected Old Well Decline Curve Analysis Cumulative Gas History Match

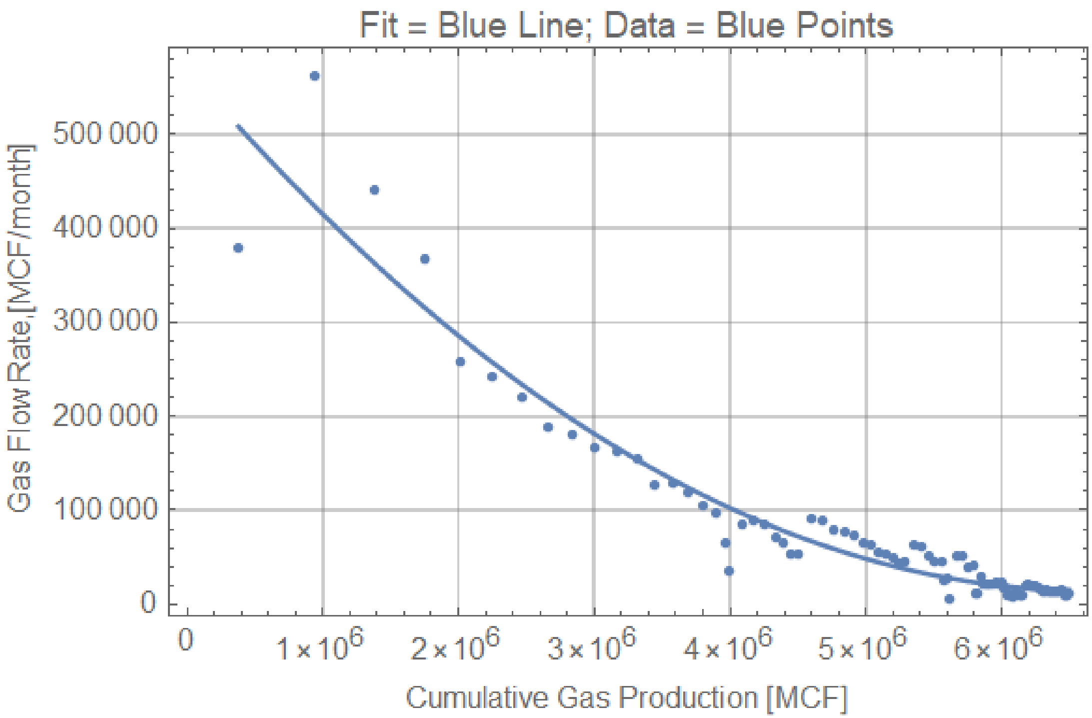

Figure 14. Selected Old Well Rate-Cumulative Analysis History Match

Table 2. EUR calculated for representative old well

Methods	Calculated EUR	Recovery
Exponential	6.61 BSCF	98.2%
Rate-Cumulative	6.64 BSCF	97.8%

The relatively young well that we selected started to produce at January 1st, 2016. The date is chosen so that we could have the data for at least 24 months cumulative production history. The history matches for the selected young well is shown in **Fig. 15 – 17**. The exponential decline curve analysis gives 3.84 BSCF EUR and 91% recovery. However, the rate-cumulative method results in 3.62 BSCF EUR and about 96% recovery. The difference between these two factors is greater than that of the old well. If we treat the two results as lower and upper bounds on well lifetime, the conservative estimation of the well production will be the average, which is 3.73 BSCF. The corresponding recovery factor will be 93.7%. Learned from the trend of both well EUR estimation, we found out that use first 24 month to do the analysis in this area will lead to underestimate of the EUR.

Because most of the wells from 2010 to 2016 has already produced an overwhelming fraction of its EUR, corresponding to the current configuration of well-completions, we can just use the current cumulative production from the section as the measure of the value. Such a characterization is quite reliable and can help to avoid conclusions introduced by artifacts of the applied method of calculating EURs. For the 64 wells after 2016, the decline curve analysis will cause more errors because the basic assumption for this type of method requires at least 24 months production history.

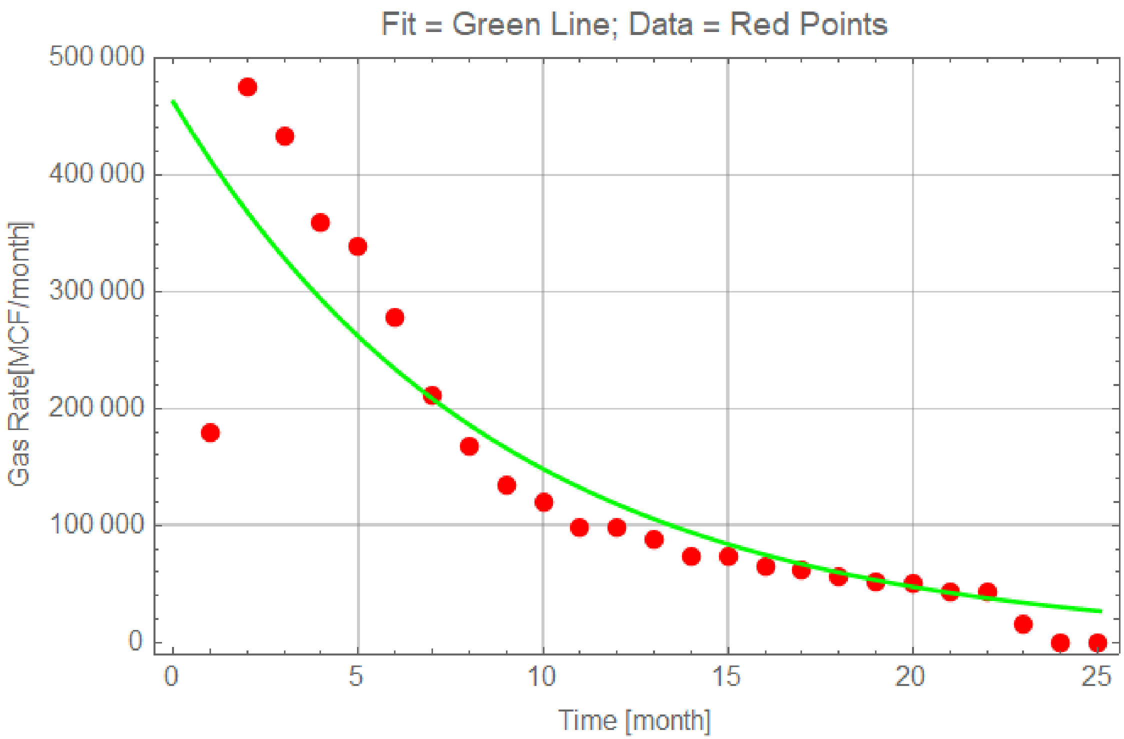

Figure 15. Selected Young Well Exponential Decline Curve Analysis History Match

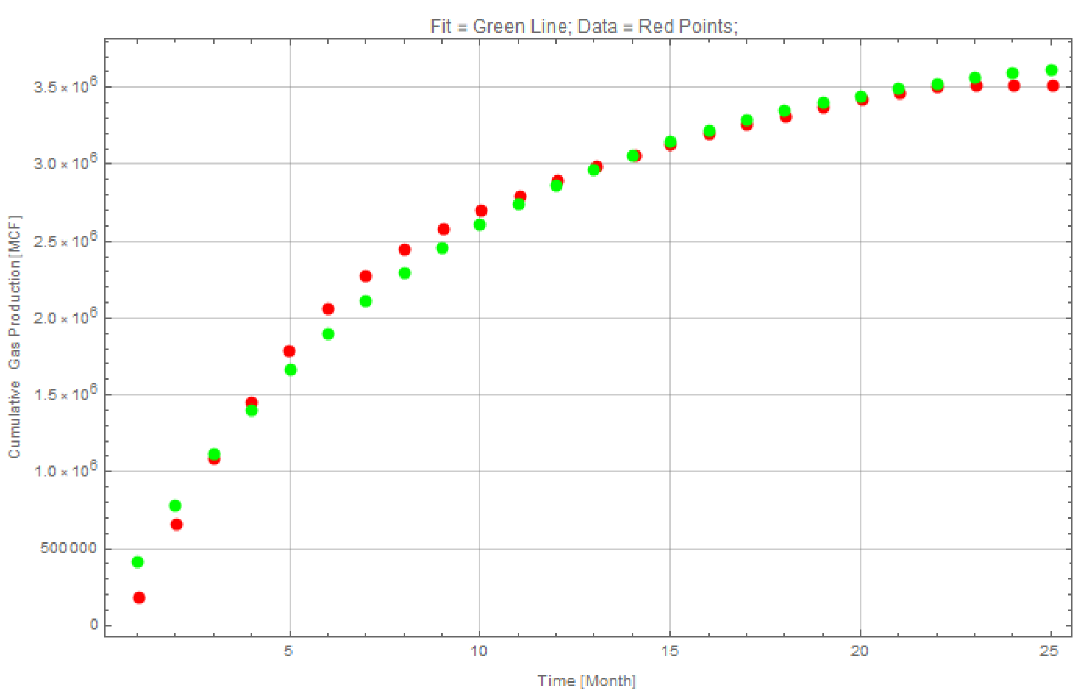

Figure 16. Selected Young Well Decline Curve Analysis Cumulative Gas History Match

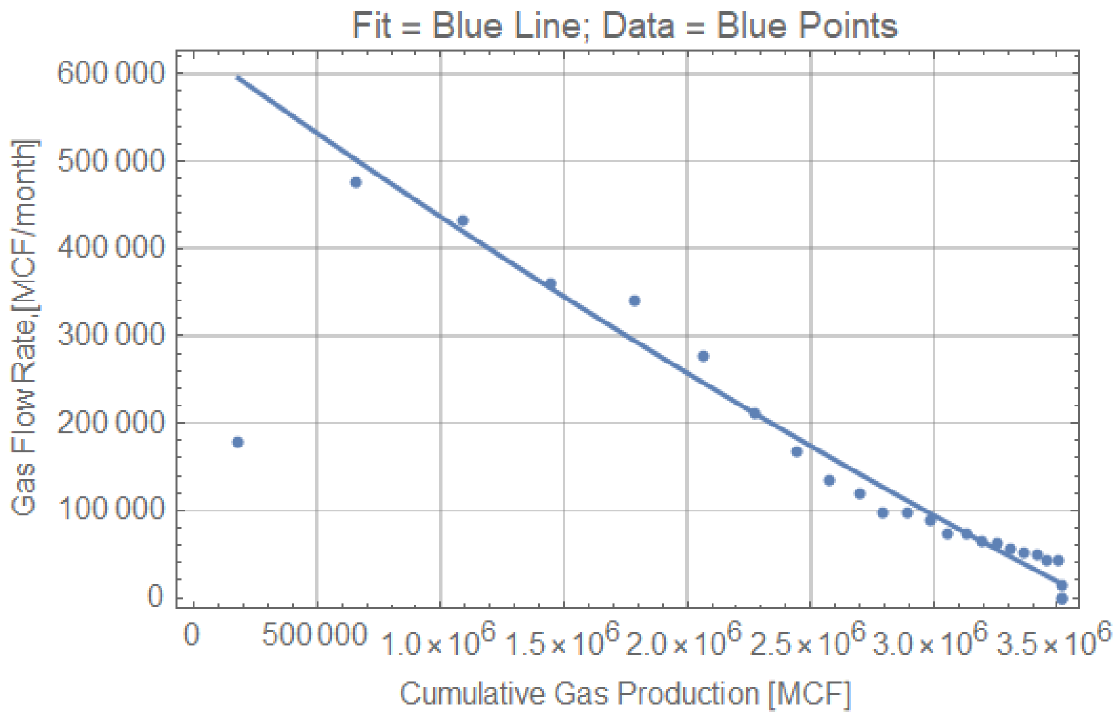

Figure 17. Selected Young Well Rate-Cumulative Analysis History Match

Table 3. EUR calculated for representative young well

Methods	Calculated EUR	Recovery
Exponential	3.84 BSCF	91%
Rate-Cumulative	3.62 BSCF	96%

We first repeated the previous study by using the present section analysis data based on well assignment corresponding to the location of the wellhead. We added up all the data based on wellhead location and without any well fraction assigned in each section. That means the well path is ignored and the well contributed fully to the section. In this way, we could see how big the difference is if we choose middle point as the reference point and assigned well fraction. The results based on wellhead location are shown in **Fig. 18 – 20**. **Fig. 18** is the cumulative gas plot per section. **Fig.19** and **Fig. 20** are the corresponding well count and proppant usages. As observed, most wells has cumulative gas production less than 10 BSCF. The main production comes from the north of Desoto parish, which we called the dense area. For the dense area, the well count is much more than other sections. If we normalized the cumulative gas based on the well count, we could observe that most sections will produce between 3 BSCF to 7 BSCF. The variety in the cumulative production distribution brings up the issue whether the production variables follow any trend when investigating an individual section's proppant data. From the tier maps based on the wellhead location, the proppant distribution seems to have had some connection with the cumulative gas production.

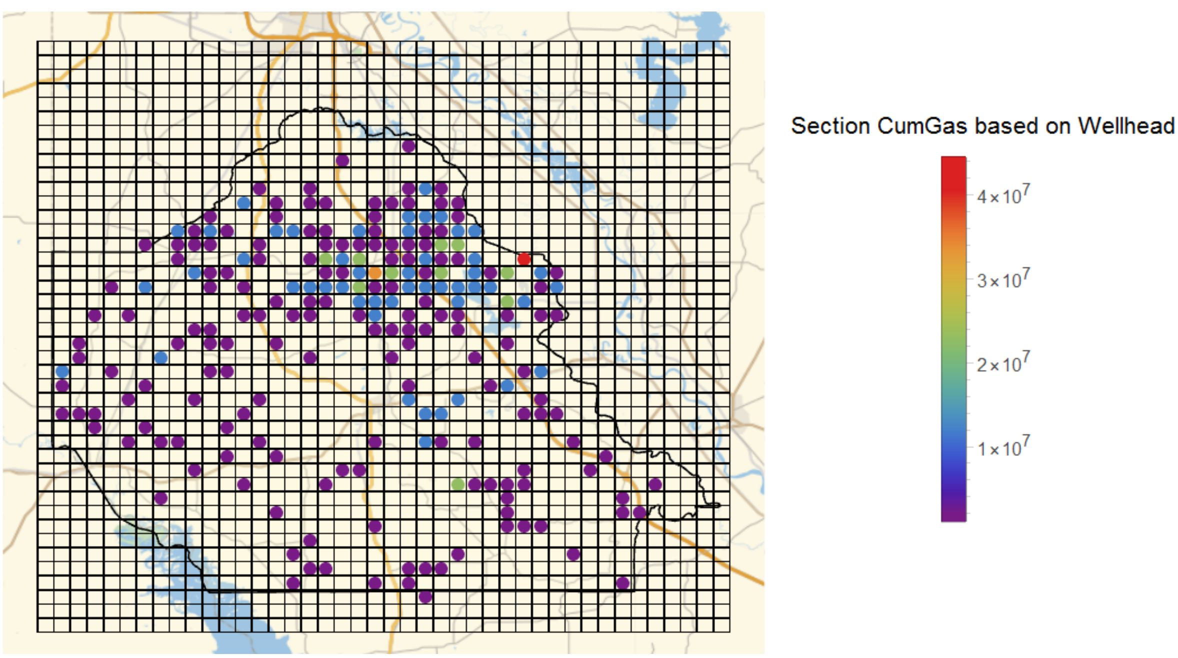

Figure 18. Section-based Cumulative Gas based on Wellhead Location

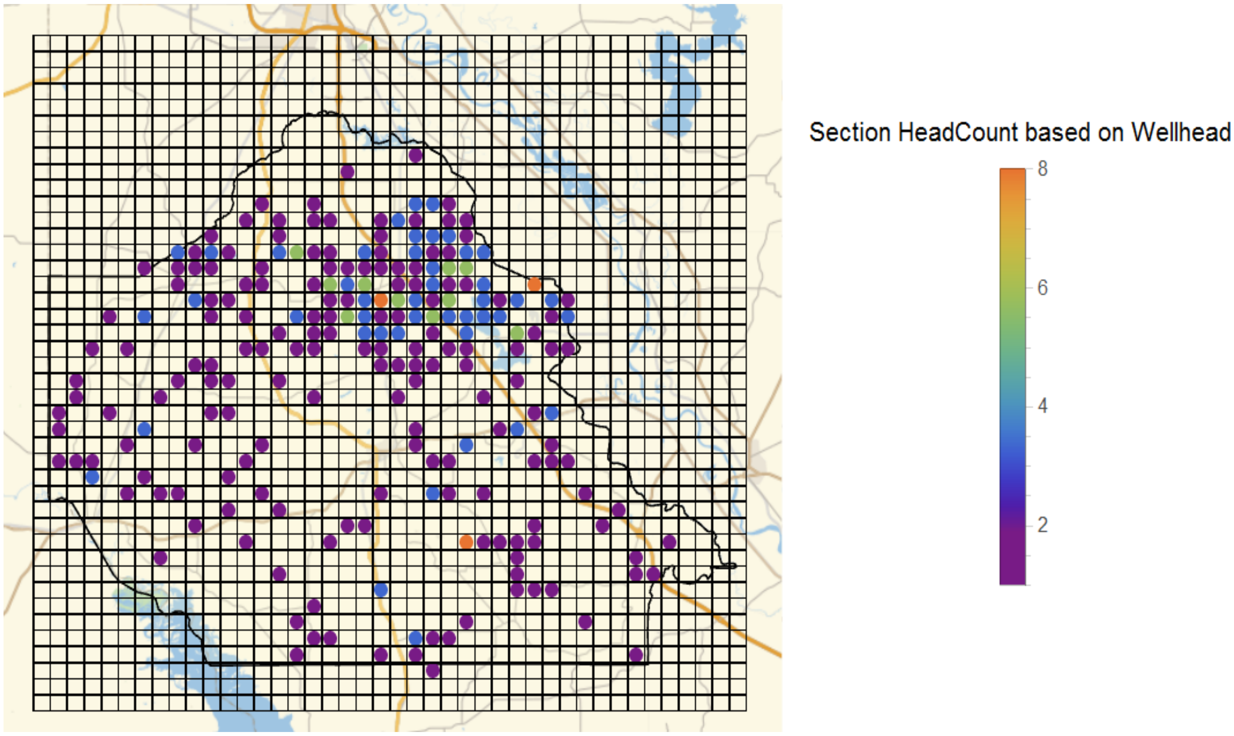

Figure 19. Section-based Head Count based on Wellhead Location

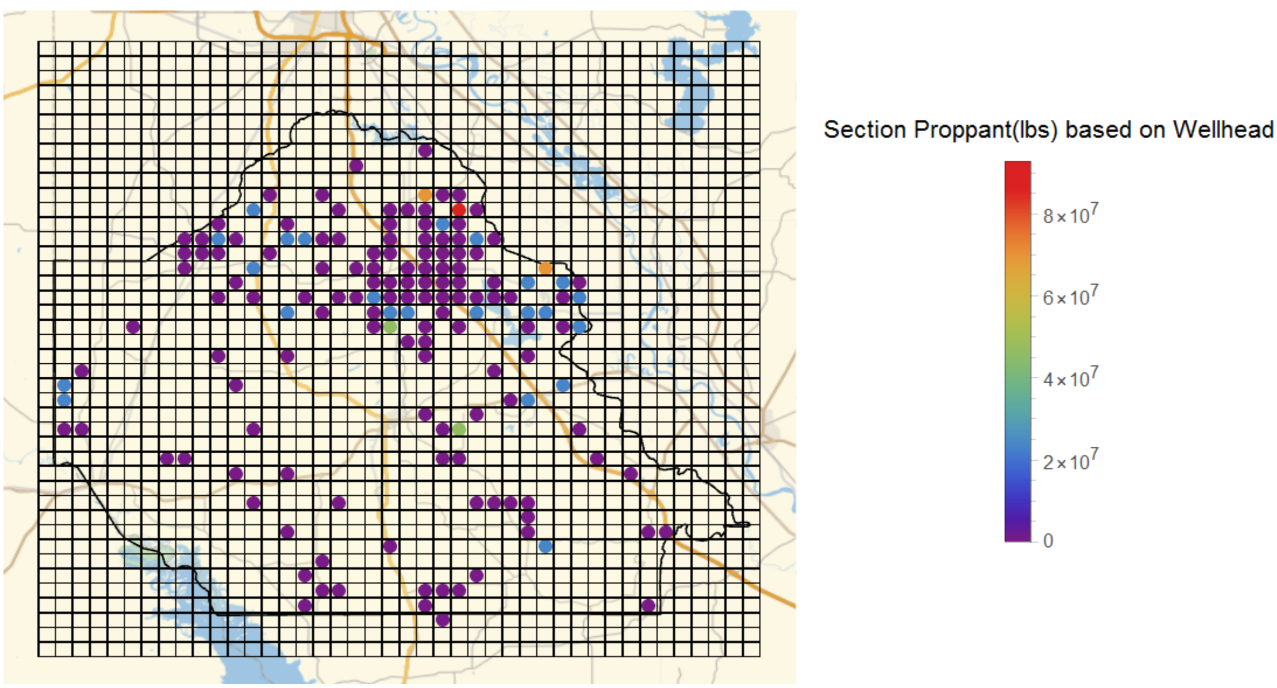

Figure 20. Section-based Proppant based on Wellhead Location

The variety in the cumulative production distribution brings up the issue whether the production variables follow any trend when investigating an individual section's production data. By looking at some relationship between factors, we observed a weak uphill relationship between cumulative gas per section and proppant per section as shown in **Fig. 21**. The data on the left most of the plot shows similar proppant usage but more cumulative gas. We note the data dots on the rightmost has extremely high proppant usage with a small production with only one well. There is a high probability that the proppant with greater than 80 million data is reported incorrectly. If we delete the one data greater than 80 million, the correlation is much better, as shown in **Fig. 22**. The R-square boosts from 0.31 to 0.44, which is closer to the moderate uphill linear relationship. Most data fall below 50 million. Relatively better correlation is expected if the analysis is made below 50 million proppants because the proppants cannot boost the production unlimitedly.

As noted, the dataset of total water is extremely small. Almost 70% of actual total fluid data were missing. Several reasons accounted for the missing data. By checking on the data sets provided by Drillinginfo, we noticed that many operators report the total proppant use instead of total water. FracFocus also doesn't have record for lots of wells. Moreover, the data that satisfy the strict criteria of selection barely has total fluid data. The remaining high-quality data indicates a strong correlation between cumulative gas per section and total water per section, as shown in **Fig. 23**. This relationship is questionable and requires more analysis in the future with more water usage data published. The observed linear regression model might be enhanced by attempting to make some correlations.

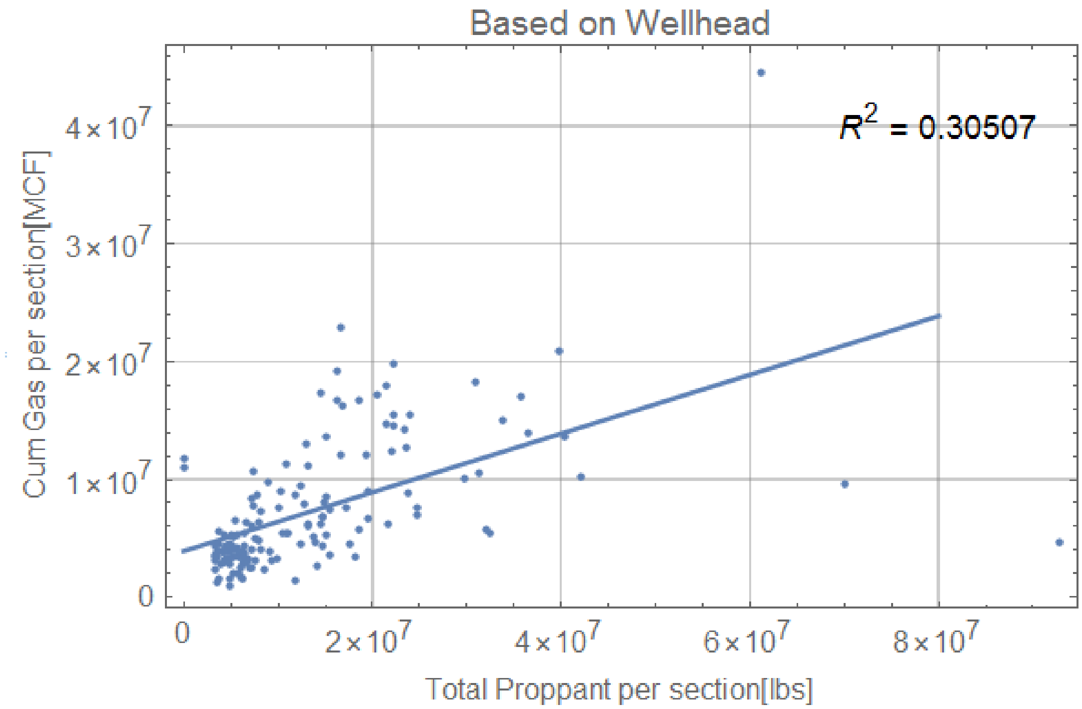

Figure 21. Cumulative Gas vs. Total Proppant per section based on Wellhead Location

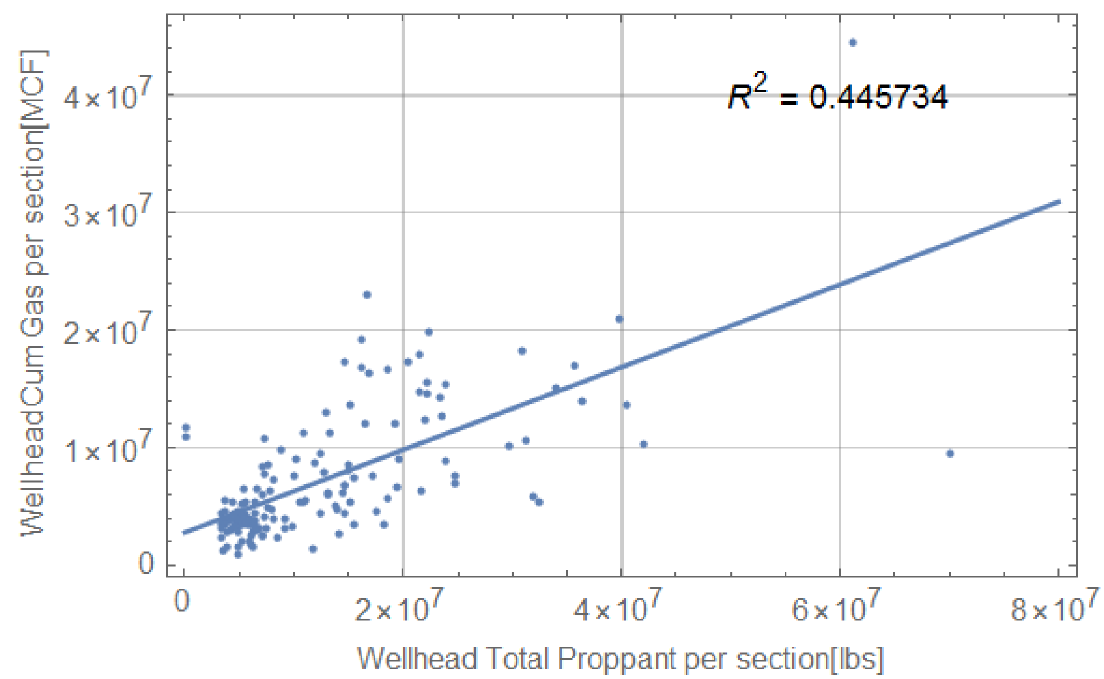

Figure 22. Cumulative Gas vs. Total Proppant per section based on Wellhead Location with one outlier omitted

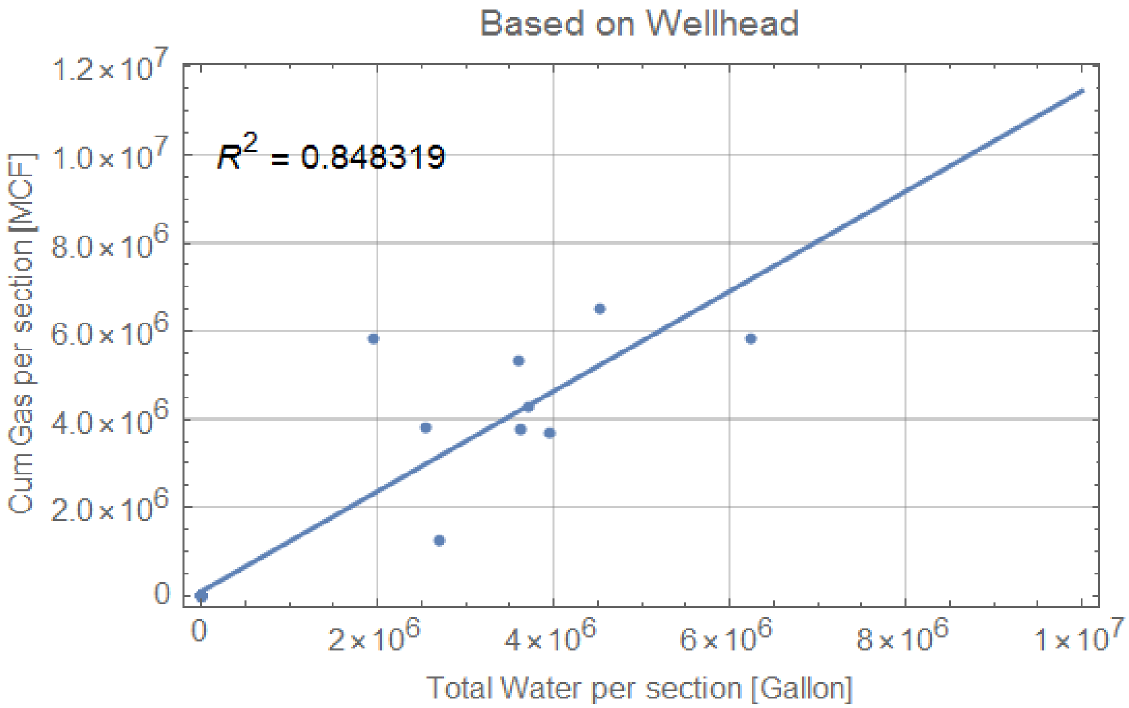

Figure 23. Cumulative Gas vs. Total Water per section based on Wellhead Location

Based on our assumption, the wellhead location might not be the best representative for horizontal wells. The section analysis based on the middle point of the well might provide better correlation. We repeated the same steps of creating tier maps based on wellhead location, but we used midpoint of well location instead as a criterion to make section contribution. The wells will also contribute fully to the Pseudo-sections. The results are shown in **Fig. 24 – 26**. We find out more Pseudo-sections are filled with data and the scales of data has changed. The maximum cumulative gas range has reduced to 25 MSCF, compared to the 40 MSCF maximum cumulative production in the section analysis based on wellhead location. The maximum well count changed from 8 to 7. The section proppant scale hasn't changed a lot, but there are some sections with highest proppant number based on wellhead location spread out in more sections.

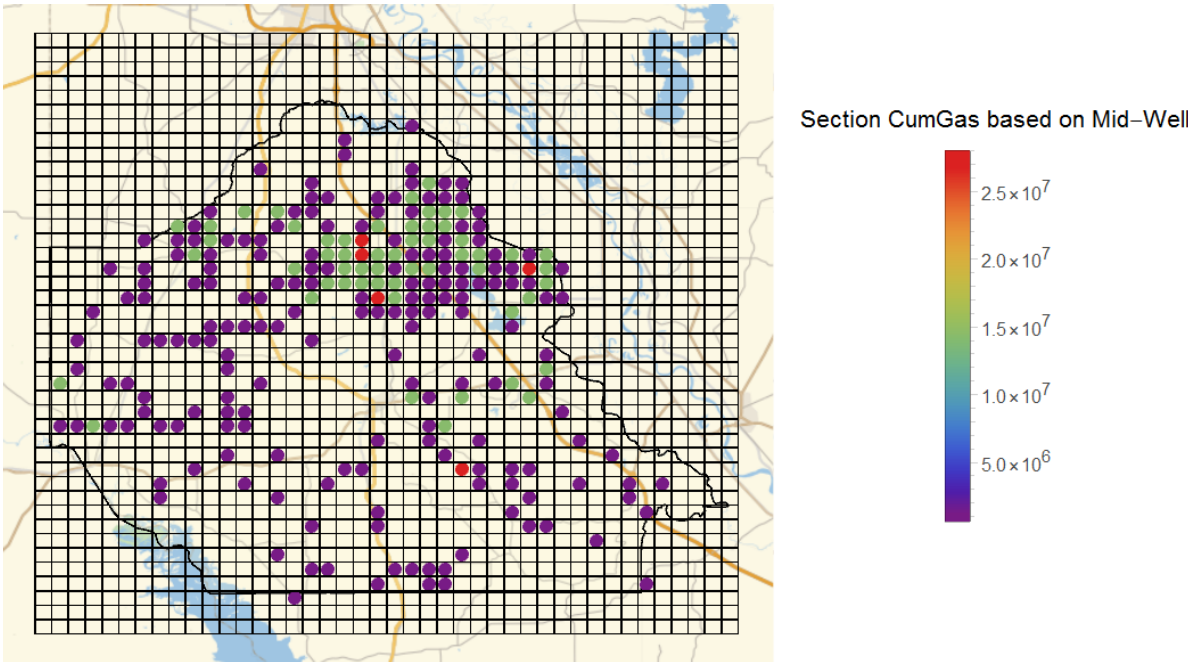

Figure 24. Section-based Cumulative Gas based on Mid-well

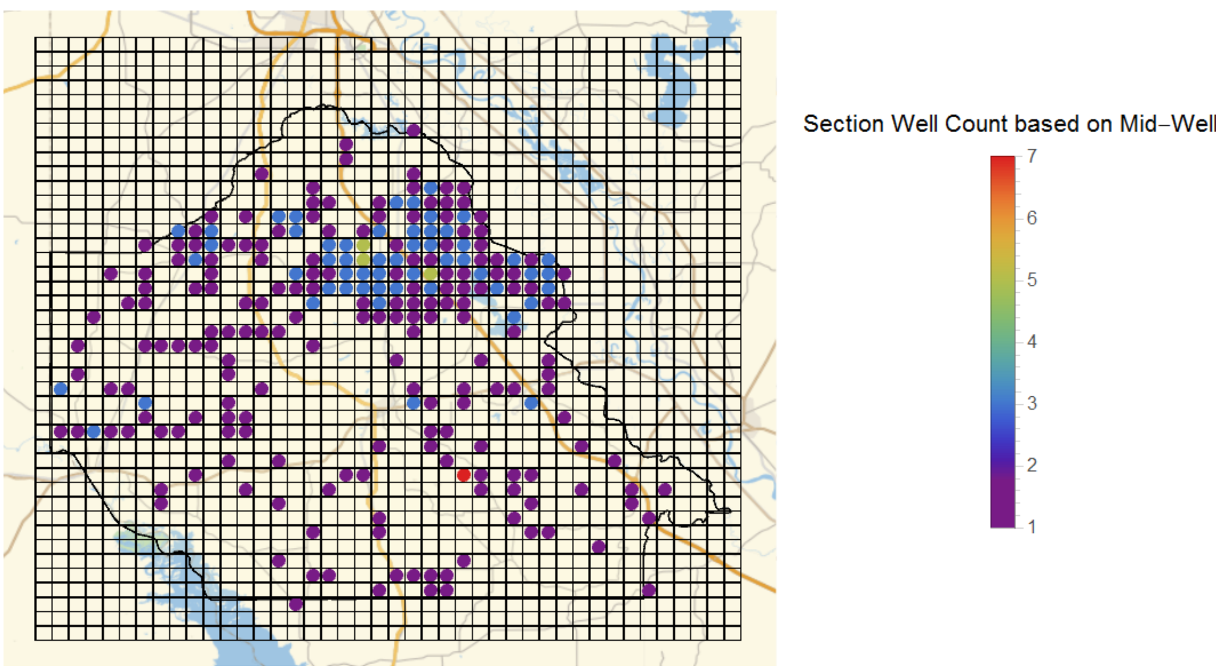

Figure 25. Section-based Well Count based on Mid-well

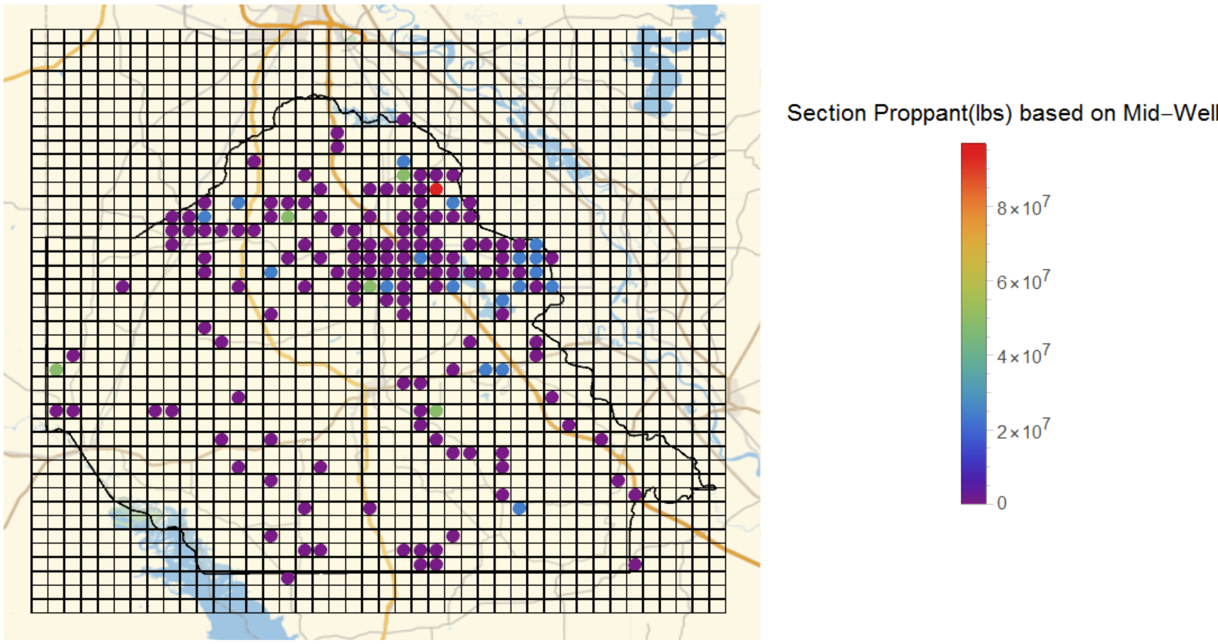

Figure 26. Section-based Proppant based on Mid-well

We note that the full contribution to the Pseudo-sections based on mid-well location doesn't help use to improve the total proppant and total water versus cumulative gas correlation, as shown in **Fig. 27 - 29**.

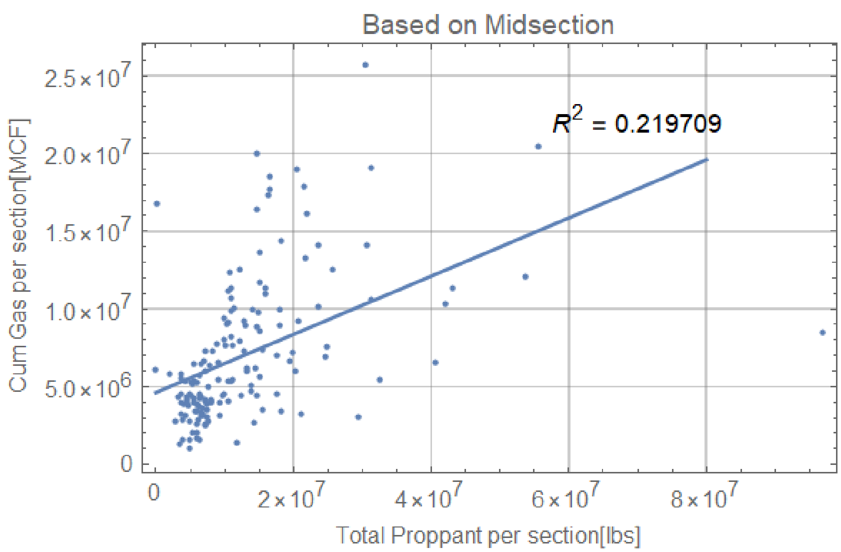

Figure 27. Cumulative Gas vs. Total Proppant per section based on Mid-well Location

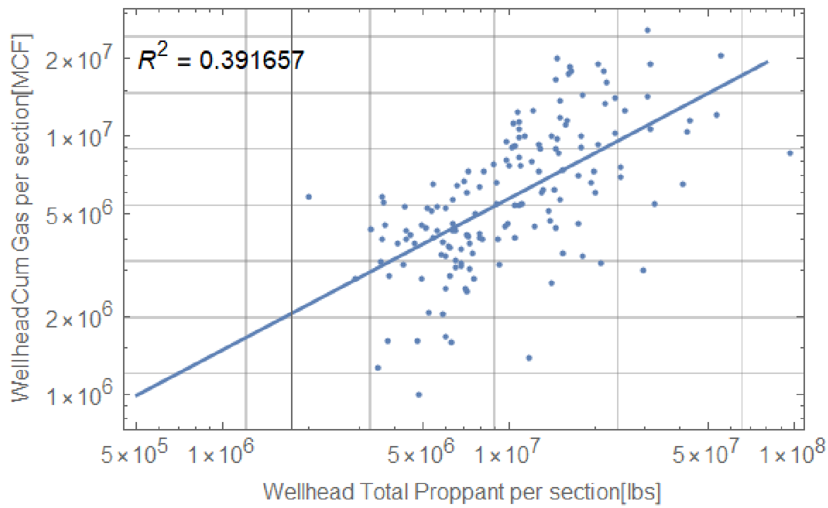

Figure 28. Cumulative Gas vs. Total Proppant per section based on Mid-well Location with one outlier omitted

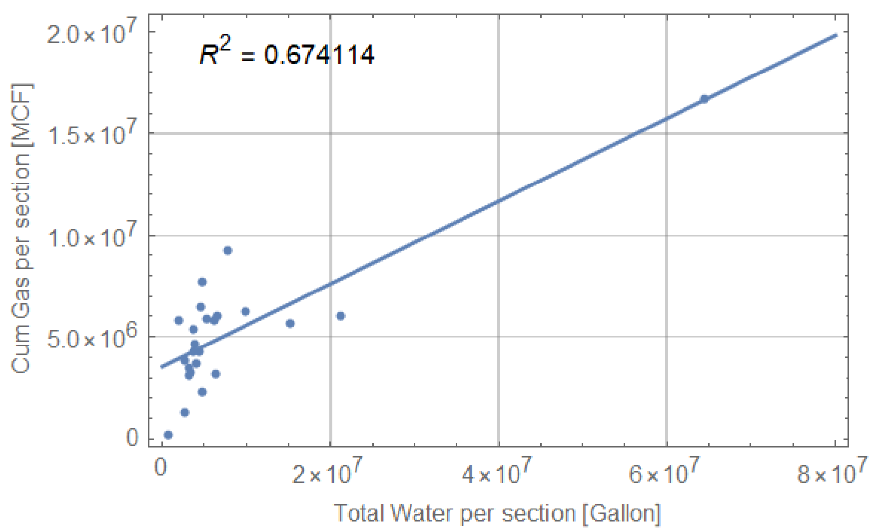

Figure 29. Cumulative Gas vs. Total Water per section based on Mid-well Location

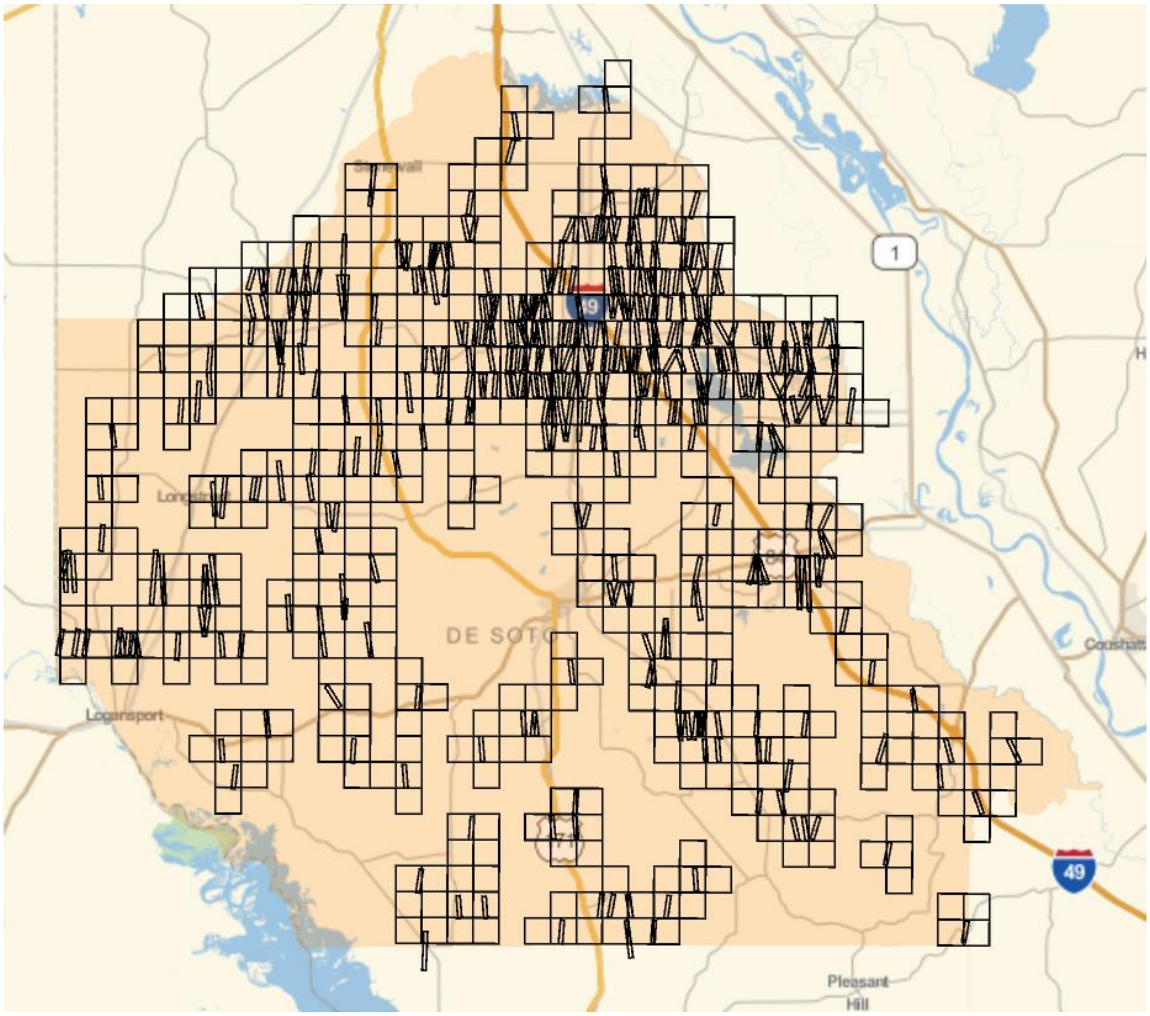

Figure 30. Drainage Area for Wells in Desoto Parish

One reason account for the failure of the middle point method is that the well wasn't analyzed proportionally. Since the subsurface path of many wells crosses more than one section, we need to assign geo-spatial weight percentages to the well. Using the weighting factors, we then can create new weighted maps of production and completion database organized by Pseudo-sections. In order to calculate the weight factor, we identified the well distribution as shown in **Fig. 30**. The rectangles are the drainage area of individual well and the squares are the corresponding Pseudo-sections. We note that after the fitting, two wells go out of DeSoto Parish area. The outside part will not be taken into calculation. We tested new method of assigning wells to Pseudo-sections and adjusted to make it align with the previous method. By doing so, we found out that the accuracy of the Pseudo-section coordinate systems influences the results a lot. Small changes in the Pseudo-section will greatly influence the weighted percentages to the well. There exists an artifacts error. However, because we compare our Pseudo-section with the Google Earth coordinates, the error should not be huge. It seems that most drilled wells are fitted within a Pseudo-section. Very few wells have small portion outside the Pseudo-section. We are likely to think that operators in the field tend to adopt the horizontal drilling strategy that fits our Pseudo-sections, whether intentionally or unintentionally. The assumption of individual well drainage area will have some effect on the well-distributed portion of drainage area.

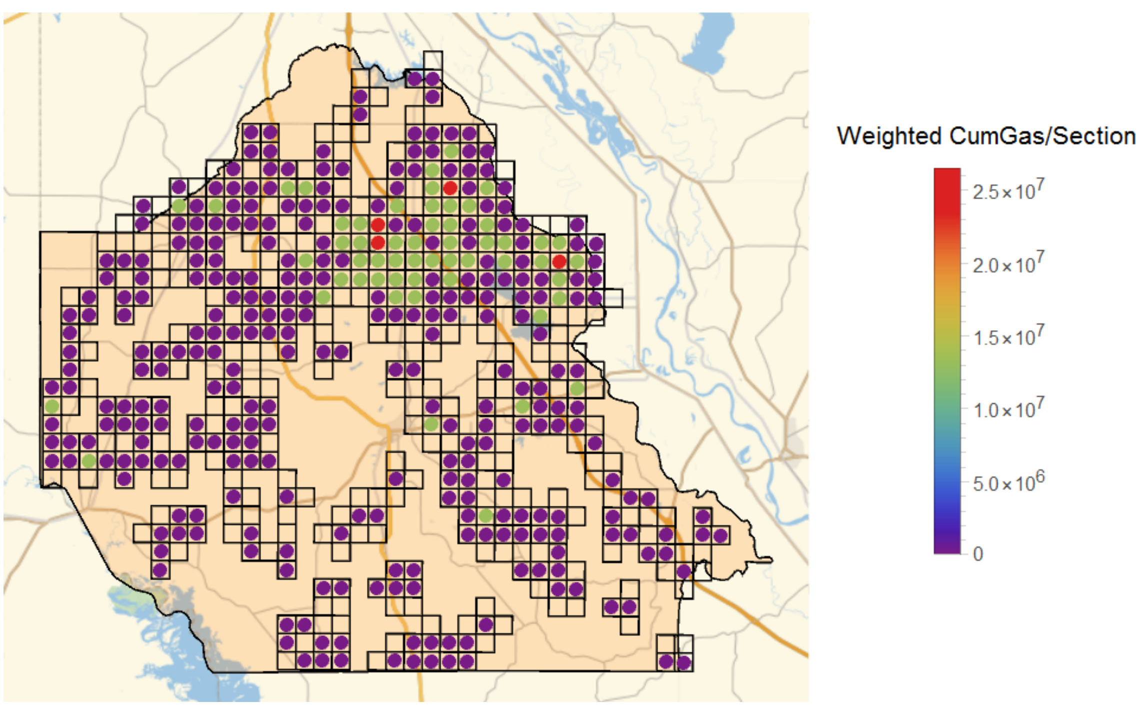

Figure 31. Weighted Cumulative Gas Distribution Map

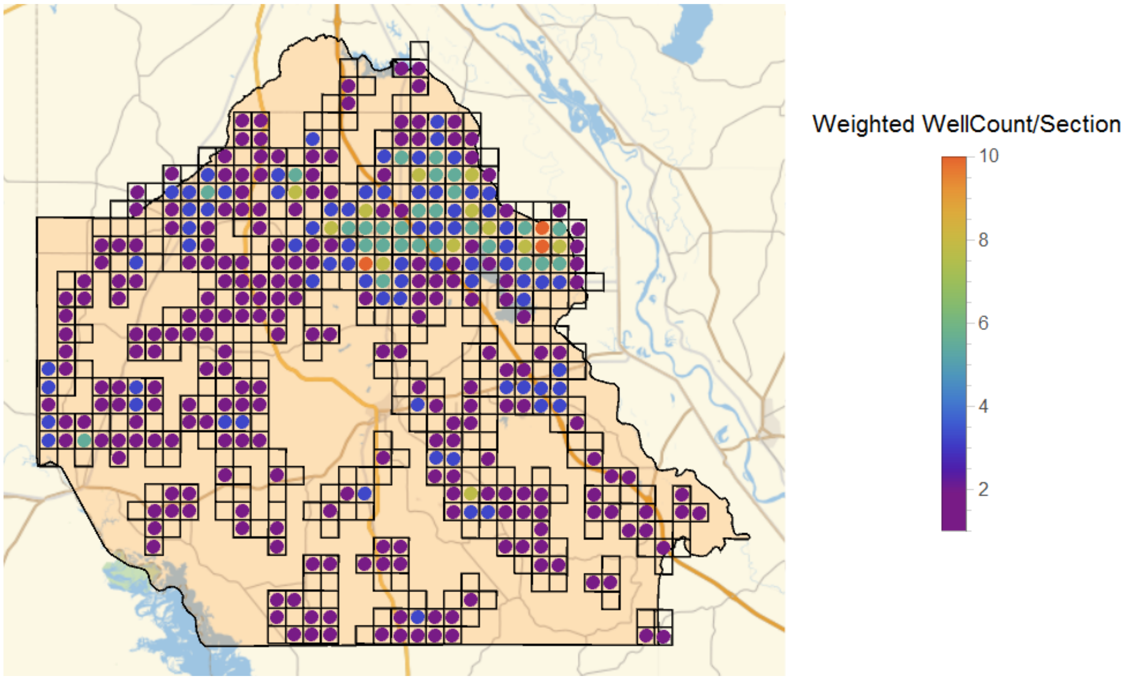

Figure 32. Weighted Well Count Distribution Map

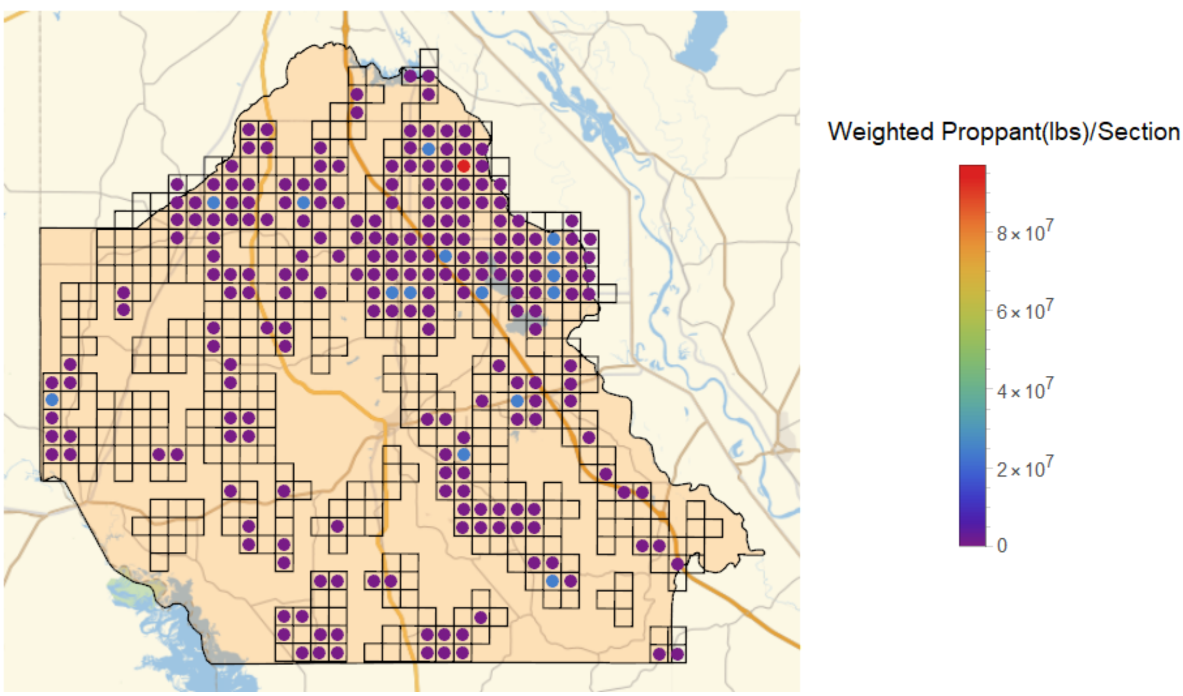

Figure 33. Weighted Proppant Distribution Map

The results of the weighted map were shown in **Fig. 30 - 34**. The data variation of weighted proppant is hard to observe with less data change cause by the one outlier. From previous observation, we note that the proppant with data greater than 80 million has high risk of being reported erroneously. Thus, we delete the data and reconstruct the weighted proppant map. After the changes, we could observe a color change of weighted proppant map has better aligned with the weighted cumulative gas map.

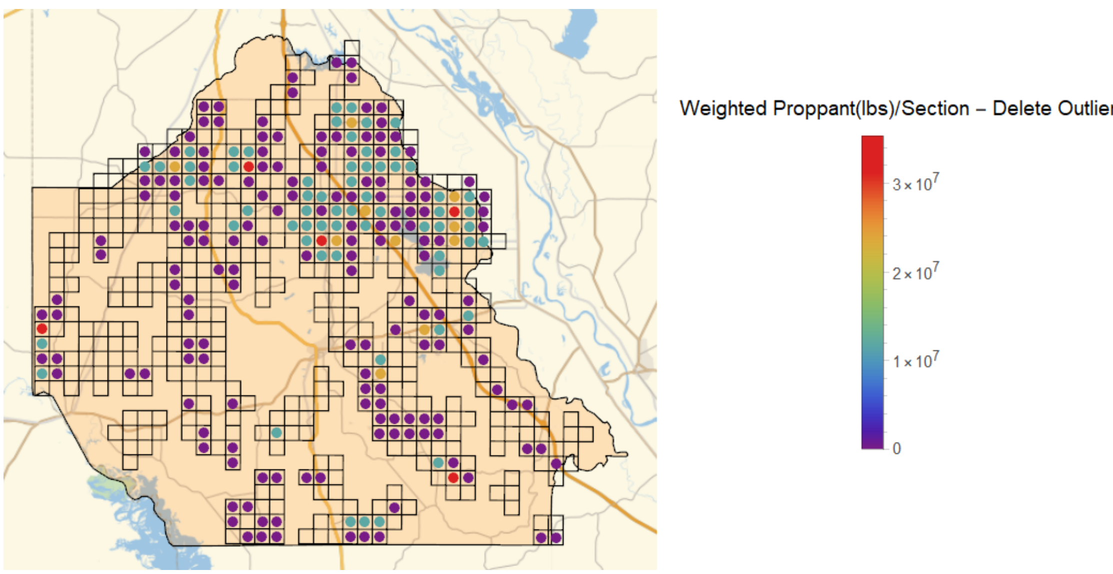

Figure 34. Weighted Proppant Distribution Map with outlier emitted

Based on the weighted map, we generated some interesting ideas although it is hard to prove some of the ideas. The well quality is one factor we should considered. Some wells produce very well, but they do not produce long enough to show their relative contribution to the value of the Pseudo-section. If in the ideal condition with enough money, good gas price, and enough resource provided, operators tend to drill additional wells and the section performance might ultimately be similar to each other and follow the stochastic nature of reservoir quality. If this is true, the results might indicate that there is little basis to look for “sweet spots”. In a statistical sense, the study area has a rather uniform “reservoir quality”.

After creating the weighted section variables, we observed a moderate positive relationship between the amount of total proppant used and the current cumulative gas production. The data range for proppant usage become smaller, but the data become denser. This is because the wells are now distributed in more sections. The correlation excludes proppant with missing data or reported zero. We could observe that some sections have low cumulative gas and proppant values. Those values might come from sections which had only one well that has been declared “unsuccessful”. The weighted cumulative gas shows the strong uphill relationship with the weighted total fluid.

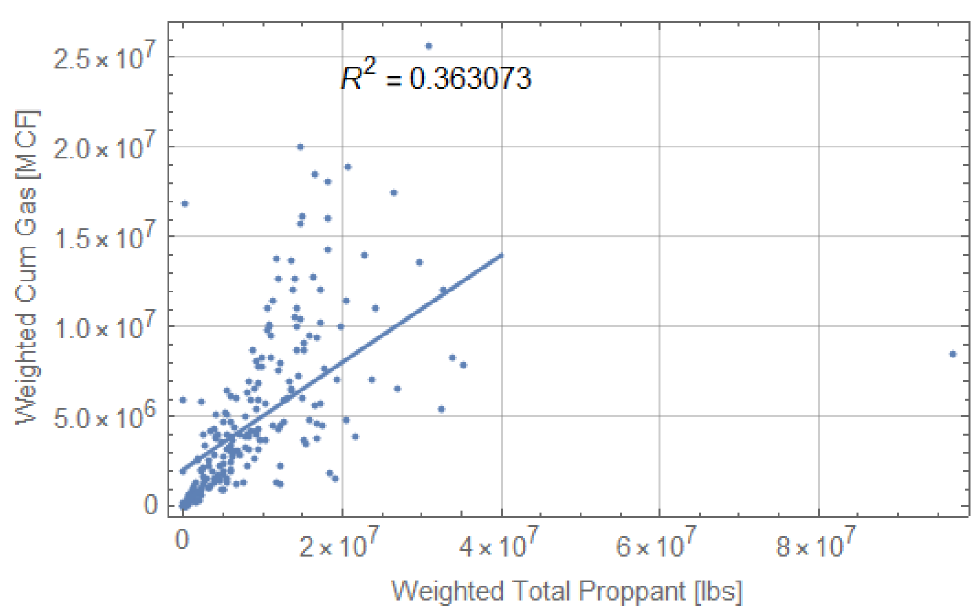

Figure 35. Weighted Cumulative Gas vs. Proppant per section

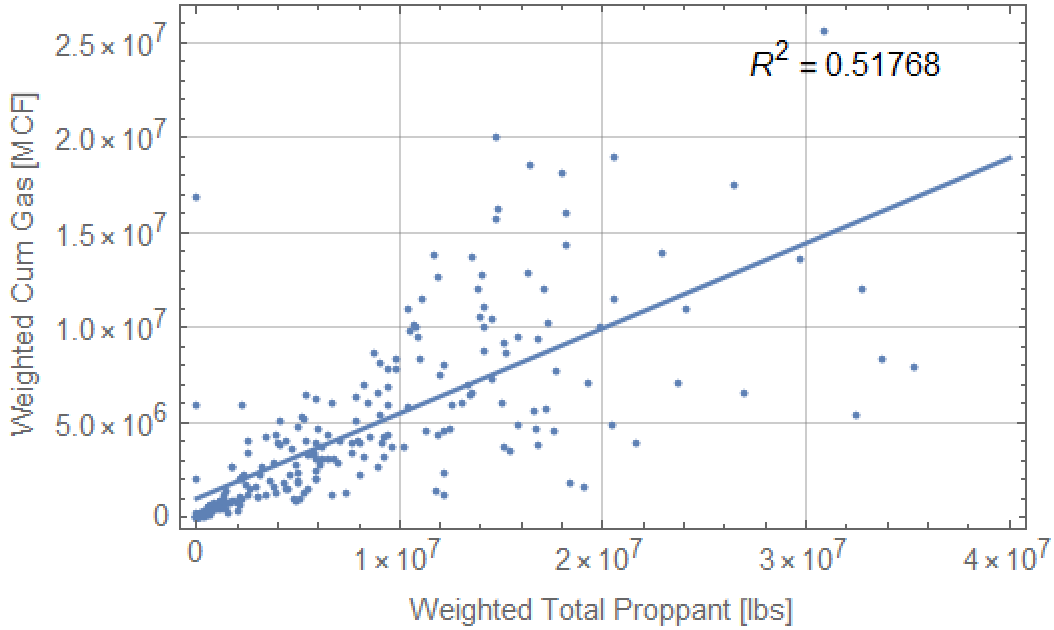

Figure 36. Weighted Cumulative Gas vs. Proppant per section with outlier omitted

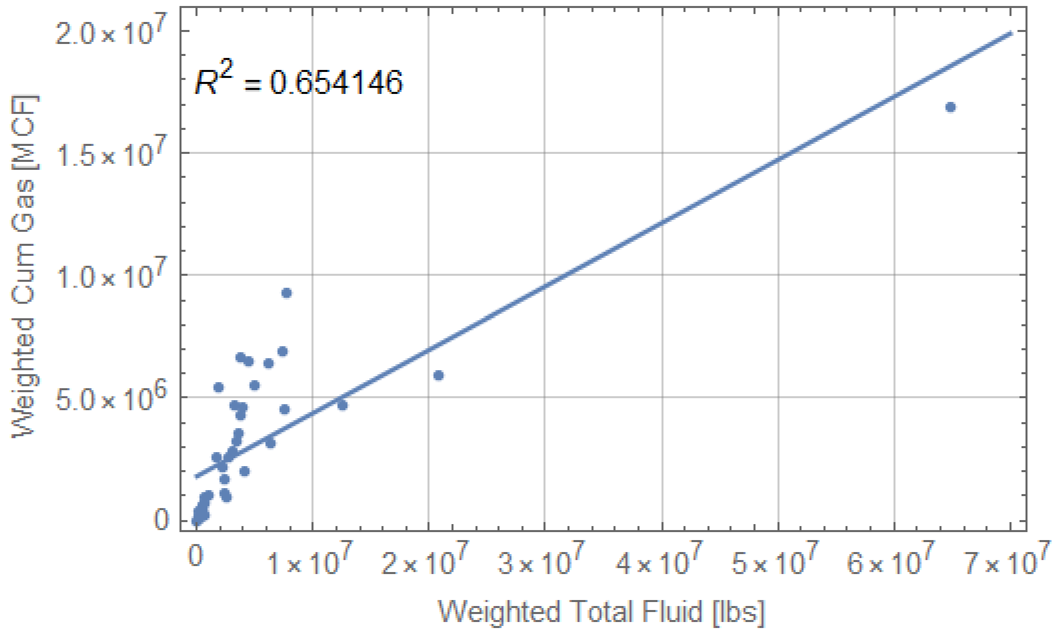

Figure 37. Weighted Cumulative Gas vs. Total Fluid per section

By looking into the graph, we note that more sections are generated compared to the wellhead-based analysis. However, there exist some sections that have only one well contributing with a small percentage. We think those sections would cause noise in the correlation plot. To test the idea, we try to filter out those sections by the criteria: for a pseudo-section with one well contribution and the well contribution less than 10%, the contribution will opt out. After filtering, 48 sections disappeared on the map. The part on the left of the Fig. is less dense than before. It still indicates an uphill relationship with slightly improved R-square.

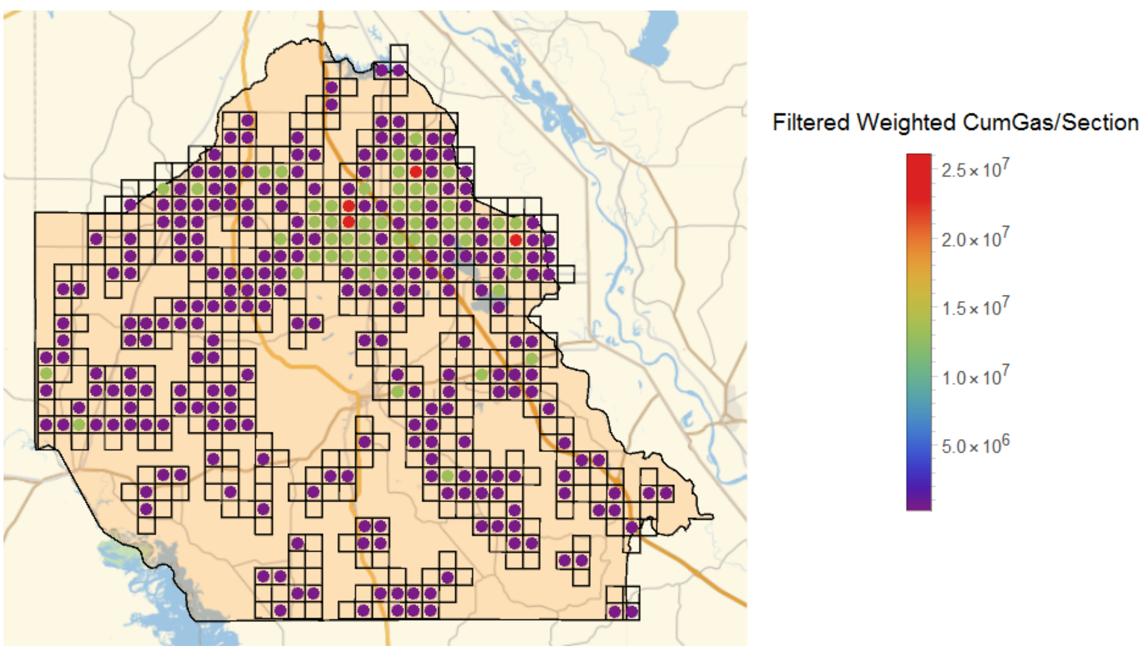

Figure 38. Filtered Weighted Cumulative Gas Distribution Map

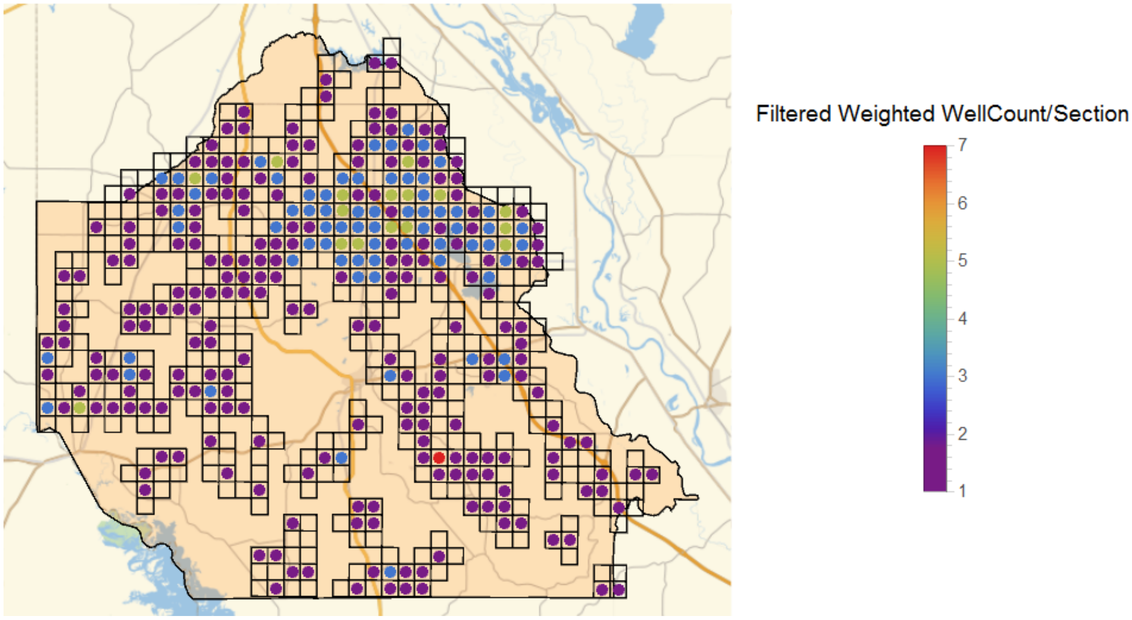

Figure 39. Filtered Well Count Distribution Map

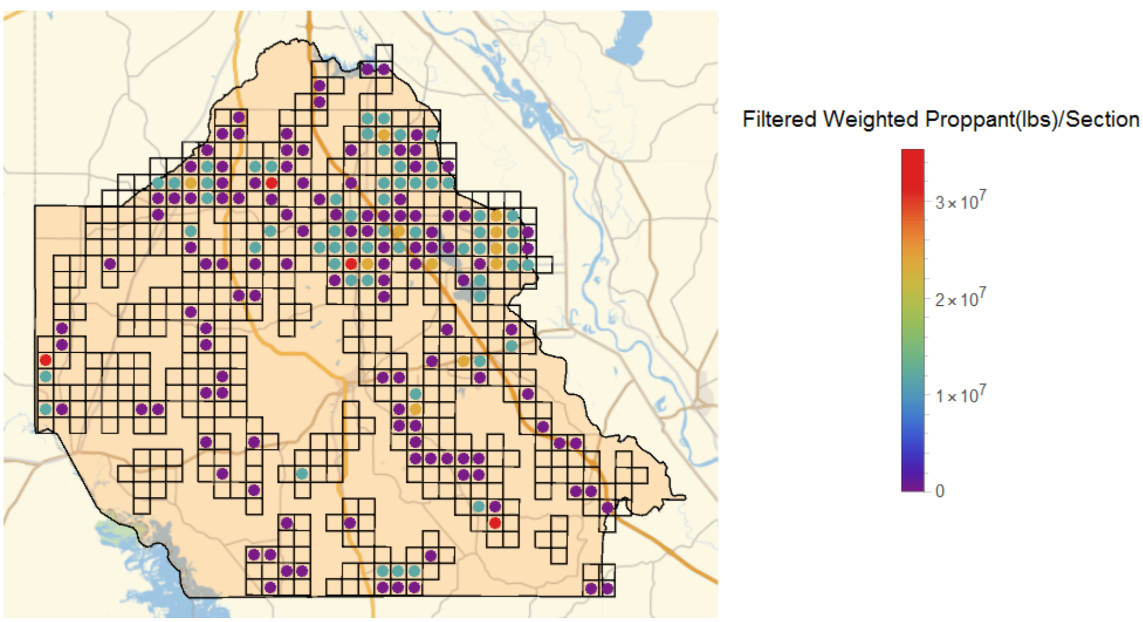

Figure 40. Filtered Proppant Distribution Map

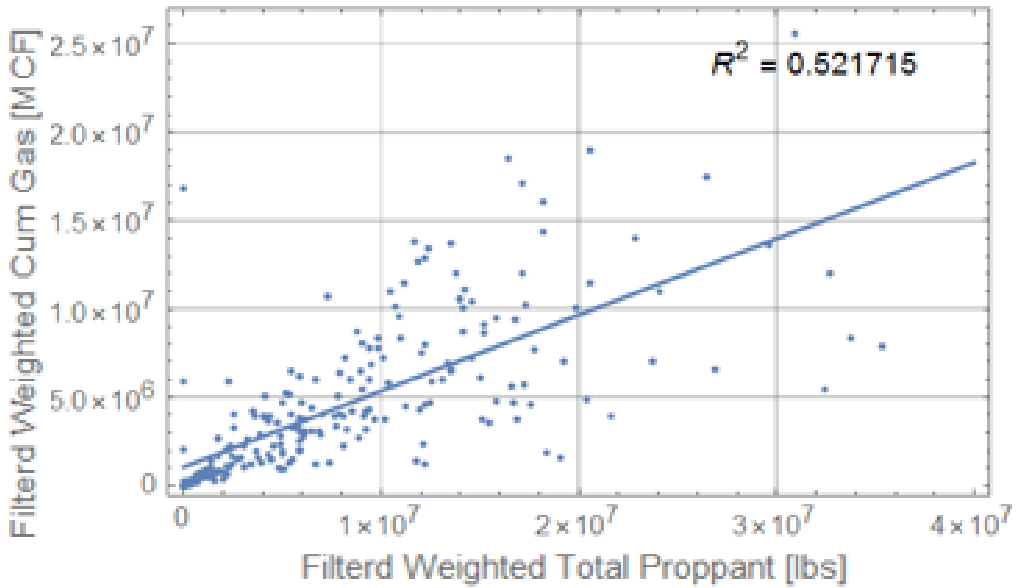

Figure 41. Filtered Weighted Cumulative Gas vs. Proppant per section

Data missing is a huge problem in this study even with the high-quality dataset. One correlation we could do is to investigate fluid loading and proppant loading simultaneously. We do statistical analysis to figure out how much sand and how much fracturing fluid used for 1ft of the well and assign the value to the data that have missing value or erroneous number. However, there is a danger that too much data assumption might lead to what we assumed. We plot the histogram of proppant per foot and try to fit the data with multiple distribution type: Normal Distribution, Lognormal Distribution, Half Normal Distribution, and Gamma Distribution. This plot shows the PP-Plot, which is known as the probability-probability plot. In a PP Plot, we compare the cumulative probability of our empirical data with an ideal "test" distribution. PP plot is a good tool to analysis how closely two data sets agree and it is commonly used to evaluate the skewness of a distribution. In our case, we are testing our data of proppant per feet against the gamma distribution in the terms of cumulative probabilities. The data dots do not fit a perfect straight line, but it is the best fit so far. The histogram might be misleading because it is largely dependent on the “bin” size. The mean value of proppant per feet is 1402.6 and we will use this number. We did probability calculation and find out there is a 4% chance that the proppant per foot will be between 1400 and 1500 lbs/ft. and a 6% chance between 900 and 1000 lbs/ft. There is a danger that too much data assumption might lead to what we assumed. With too much data loss in the fluid, it is not a good idea to make so many assumptions.

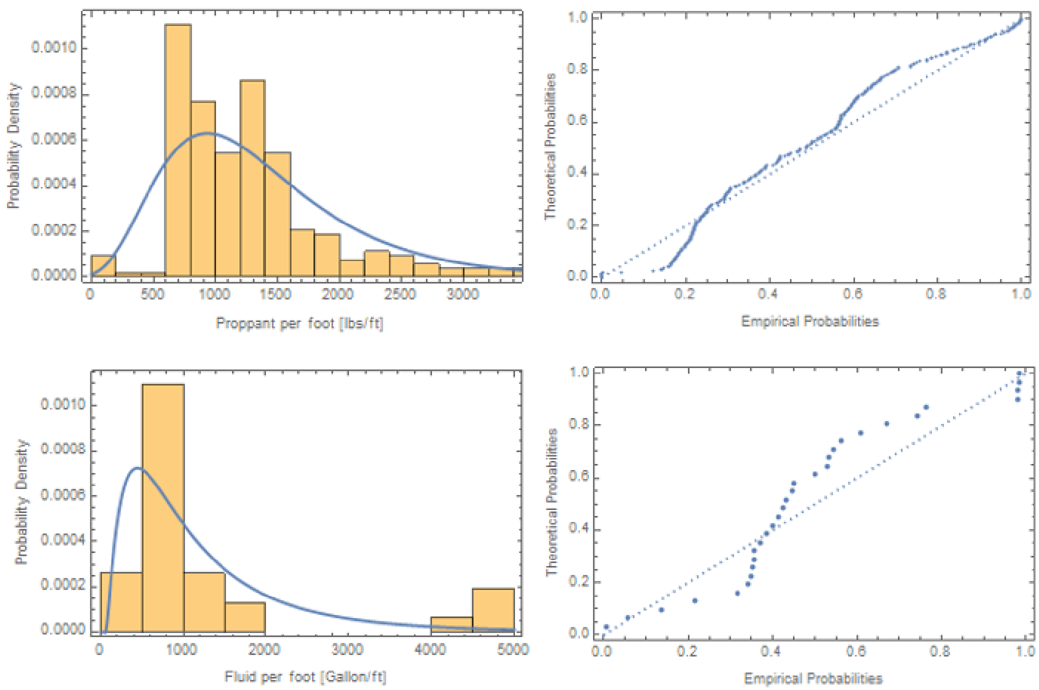

Figure 42. Statistical Distribution analysis of proppant and fluid per foot

The more convenient way is to use the proppant and lateral length correlation than the proppant per foot length directly. If the proppant data is missing or obviously erroneous, the data is replaced by the correlated proppant number. A new section with large proppant is appear due to long well length. This will lead to a closer to moderate uphill linear relationship.

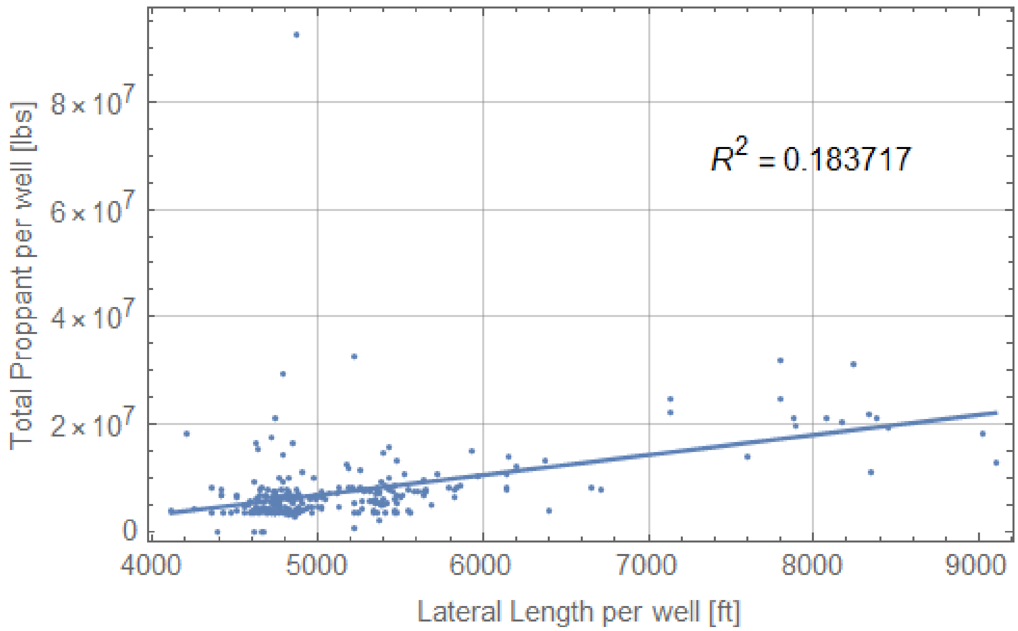

Figure 43. Total Proppant versus Lateral Length per well

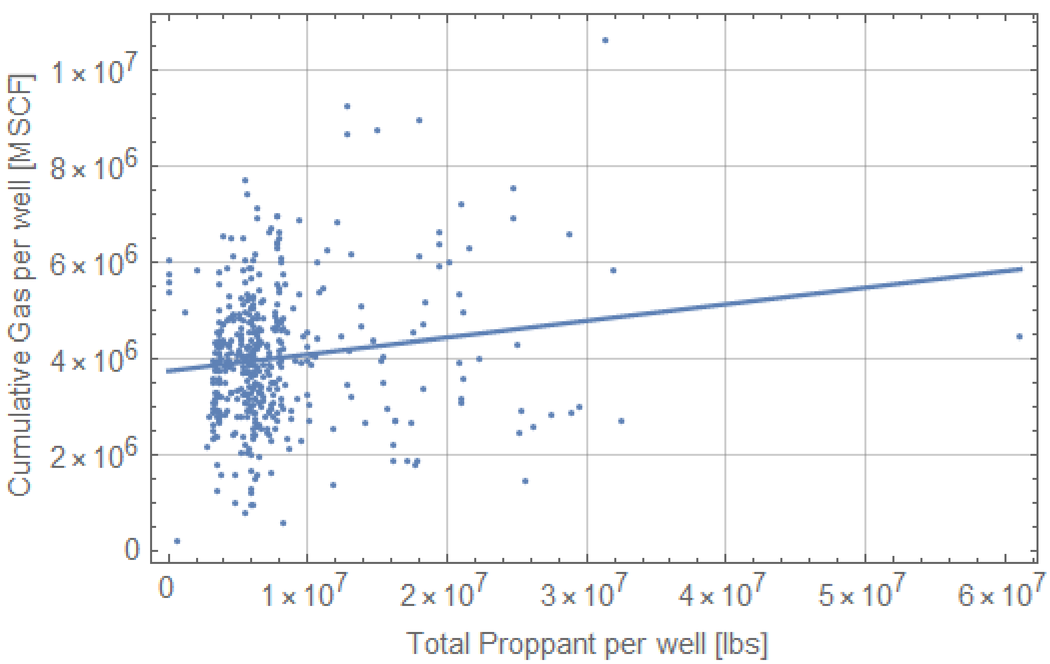

Figure 44. Cumulative Gas vs. Correlated Proppant per well

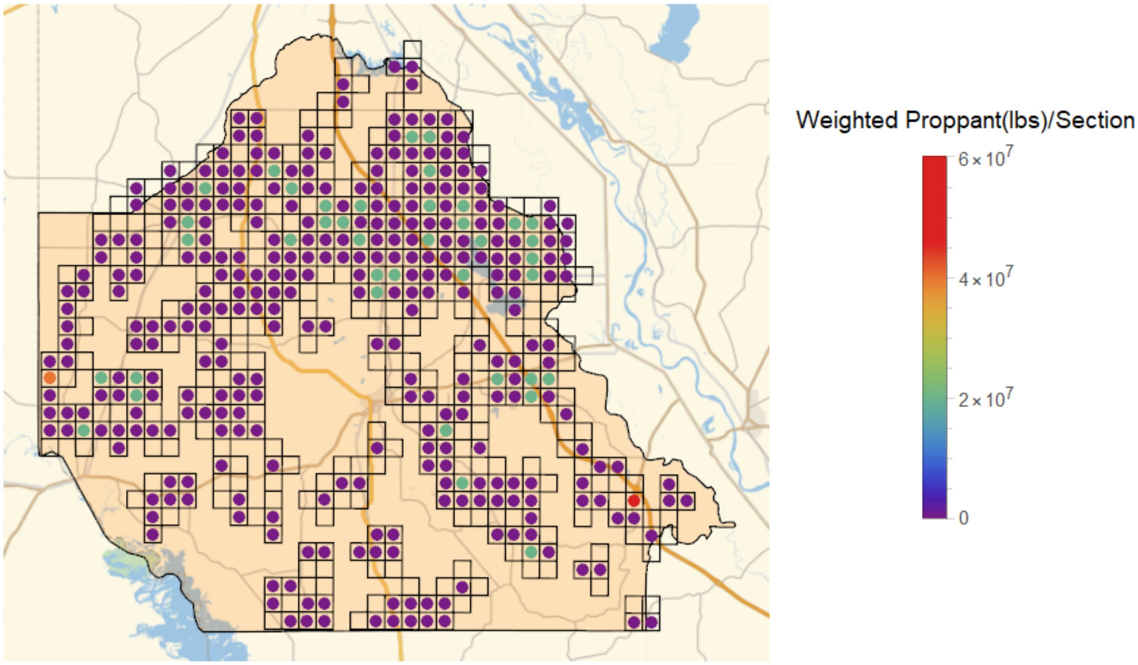

Figure 45. New Weighted Proppant per Section Map with correlated Proppant

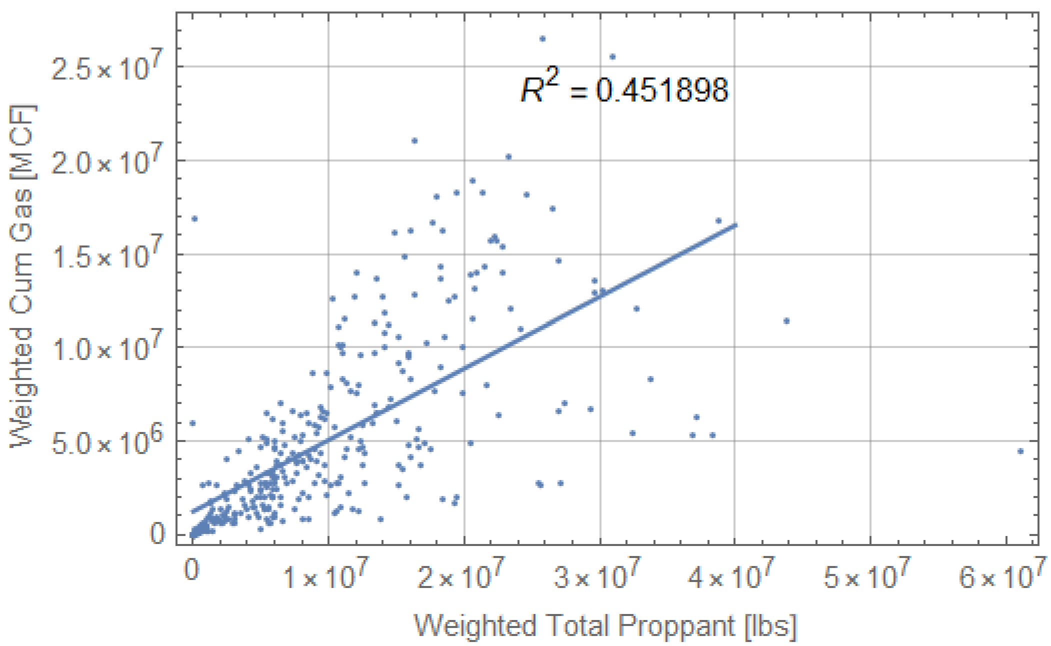

Figure 46. New Weighted Proppant per Section versus correlated Proppant Loading

CHAPTER V

SUMMARY AND CONCLUSIONS

In this work, I developed a geo-statistical study for Haynesville shale gas reservoir. This study was designed to find the impact of completion parameters on the cumulative. The study is distinguished from previous literatures of single well model for same area by integrating multiple wells in a Pseudo-section. We did this by using geo-statistical pattern to embody the distribution of completion and production properties in the form of aerial maps. In all the geo-statistical maps, wells in high quality data set after filtering is declined individually by two different methods to compare them against each other. Then, the parameters of all wells within each are added up together by assigning each well the proportion of well location distribution. The utilization of geo-statistical maps to display the multi-fractured horizontal wells gives a more practical demonstration model in the long run because it will illuminate issues such as actual effect of well spacing, proppant loading per acre compared to proppant loading per well, and so on.

The results reveal that sections with high proppant usage are most likely to produce better than other sections. Consequently, those sections produce relatively higher cumulative gas. Reducing the little contribution wells to the section will reduce the section number and reduce some noises. Thus, the R-squared value slightly improves. Generally speaking, the proppant loading has a moderate uphill linear relationship with the cumulative gas. The new shale gas wells in this area is declining except for last year. However, if the gas prices increase in the future, operator might consider drilling new wells and recomplete old wells to produce more gas. Proppant can be considered as a good indicator of drilling cost because it’s relatively controllable than other factors. Operators in this area could see the approximate proppant usage distribution and has a general estimation of the better location to spend more on drilling. Based on our calculation, recover 1 MSCF cumulative gas requires 2 lbs. proppant loading. The recent gas price now is around 3 dollars per MSCF. The normal proppant cost around 0.05 to 0.1 dollars per pound, and the synthetic proppant cost around 0.4 to 0.5 dollars per pound. (Timothy Fitzgerald, 2013). There is room for benefits.

Not deniably, this study has some limitations that cannot be ignored. First, it is impossible to have accurate data for all the wells. The analysis is subject to various errors. The financial cost for this research is super low. To compromise for the low cost, the research will suffer from missing data. We have done data quality check to minimize the errors, but obviously, we cannot erase all the errors without drastically decrease the information available for the analysis.

Indeed, after the data quality check, most data were doomed due to flawed data and missing values. Some data was excluded based on experience, but it might not always be the case. Second, different companies have different proppant selections criteria. The ability for the proppant agent to keep fractures open is different, thus, the total amount of proppant use is different. This will cause fracture conductivity to vary a lot and finally affect the ultimate recovery. Third, analysis of the “sweet spots” of the Haynesville shale represent the highest level of the Haynesville shale production. The small sample size can’t effectively represent the whole horizontal well completion parameters in Haynesville shale. The result might be too optimistic. Lastly, some wells have different well quality because of the length of well. They are not “bad wells”, but they might need more time to produce a substantial amount of gas.

There is plenty of room for improvement in such study. The study is developed specifically for the Haynesville formation in Desoto Parish, North Louisiana. It would be of great interest to expand the study to cover the entire play of the Haynesville shale or in other unconventional gas assets to see if there exists some correlation. With more area considered, variations in geological features can be taken into consideration. More study is also necessary to make a more practical model by including the economics factor and uncertainties in the economics factors. Lastly, the data analysis method used is the univariate method. Multivariate analysis could be applied to make this study better. The reason we didn't do multivariate analysis in this study is due to the small sample size of the fluid data. It seems meaningless to have a relationship now with such a small group of data.

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